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RECEIVED
JUN 23 2006
PUBLIC SERVICE COMMISSION

Ms. Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602-0615

Louisville Gas and Electric Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.eon-us.com

Kent W. Blake
Director
T 502-627-2573
F 502-217-2442
kent.blake@eon-us.com

June 23, 2006

RE: *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**

Dear Ms. O'Donnell:

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.

The filing includes:

- KU's Application,
- Kent W. Blake's Testimony and Exhibits,
- Sharon L. Dodson's Testimony and Exhibits,
- John P. Malloy's Testimony and Exhibits,
- Shannon L Charnas' Testimony, and
- Robert M. Conroy's Testimony and Exhibits.

The original version of LG&E's application and testimony contains a complete paper copy of each exhibit. Each copy of LG&E's application and supporting testimony contains a CD holding an electronic copy of Exhibit JPM-3 for the testimony of Mr. Malloy and a CD holding electronic copies of two exhibits for the testimony of Ms. Dodson (Exhibit SLD-1 and Exhibit SLD-2) along with paper copies of the remaining exhibits to the testimony.

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,

Kent W. Blake

Kent W. Blake

cc: Hon. Elizabeth E. Blackford
Hon. Michael L. Kurtz

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
JUN 23 2006
PUBLIC SERVICE COMMISSION

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

APPLICATION

Louisville Gas and Electric Company ("LG&E"), pursuant to KRS 278.183 and 807 KAR 5:001, Section 8, hereby petitions the Kentucky Public Service Commission ("Commission") by application 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 Surcharge tariff ("2006 Environmental Compliance Plan"). These compliance costs are incurred in meeting the nitrogen oxide ("NO_x") and sulfur dioxide ("SO_2") emissions limits mandated by the Environmental Protection Agency ("EPA") and the Clean Air Act as amended, ("CAAA") and also in complying with the Clean Air Interstate Rule ("CAIR"), the Clean Air Mercury Rule ("CAMR"), the Clean Air Visibility Rule ("CAVR"), and other federal, state or local environmental requirements which apply to LG&E's facilities used for the generation 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. 2005-00471, *In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Authority to Transfer*

Functional Control of their Transmission System, filed on November 18, 2005, 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.

4. 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 change to its environmental surcharge tariff by newspaper publication and through a bill insert in monthly billings to its customers. 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.

5. Pursuant to KRS 278.183, LG&E is entitled to recovery of its costs of complying with environmental requirements which apply to coal combustion wastes and by-products from facilities used to generate electricity from coal.

6. LG&E is adding four new pollution control projects to its Environmental Compliance Plan to reflect its plans for complying with environmental requirements to reduce SO_2 emissions, NO_x emissions, fine particulates, fly ash and also to monitor mercury emissions. The environmental regulations creating the need for these new and additional projects are shown in the 2006 Environmental Compliance Plan which is attached to this application and to the

testimony of Mr. Malloy as Exhibit JPM-1. Ms. Dodson's testimony presents LG&E's evidence concerning the applicable regulatory requirements and how the pollution control facilities satisfy those regulatory requirements. The 2006 Environmental Compliance Plan identifies the appropriate regulatory approvals or permits which demonstrate that such projects fulfill the obligations under the applicable environmental regulations. The pollution control projects included in the 2006 Environmental Compliance Plan are:

a. Project No. 18: Installation of Air Quality Control System ("AQCS") equipment at Trimble County Unit 2;

b. Project No. 19: Installation of Sorbent Injection equipment at Mill Creek Units 3 and 4 and Trimble County Unit 1;

c. Project No. 20: Installation of Mercury Monitors at all plants;

d. Project No. 21: Installation of Particulate Monitors on all Mill Creek Generating Units.

The total capital cost of these new and additional projects to the Environmental Compliance Plan is estimated to be $66 million.

7. 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 Kent W. Blake, Director, State Regulation and Rates, E.ON U.S. Services Inc., presents an overview of LG&E's environmental surcharge plan and requests the recovery of an overall rate of return that includes an 10.50% return on common equity.
- The testimony of Ms. Sharon L. Dodson, Director, Environmental Affairs, E.ON U.S. Services Inc., describes the environmental regulatory requirements imposed

on LG&E, including the CAIR, CAMR, CAVR and other federal, state or local environmental laws and regulations.

- The testimony of Mr. John P. Malloy, Director, Generation Services, E.ON U.S. Services Inc., describes the projects in LG&E's 2006 Environmental Compliance Plan and presents evidence as to the cost effectiveness of those projects.
- The testimony of Ms. Shannon L. Charnas, Director, Utility Accounting and Reporting, E.ON U.S. Services Inc., explains LG&E's reporting and accounting for the operation and maintenance expenses associated with the proposed facilities in the 2006 Environmental Compliance Plan and affirms that the environmental compliance costs LG&E proposes to recover through its surcharge are not already included in existing rates.
- The testimony of Mr. Robert M. Conroy, Manager, Rates, E.ON U.S. Services, Inc., explains how the surcharge for the 2006 Environmental Compliance Plan will be calculated and billed under LG&E's proposed revised ECR Tariff. Mr. Conroy's testimony explains the reasons for the proposed changes in the terms of the Electric Rate Schedule ("ECR") and affirms that the calculations will be consistent with the methods and methodologies previously approved by the Commission.

WHEREFORE, Louisville Gas and Electric Company hereby requests the Commission: (1) approve the new and additional projects to the Company's Compliance Plan for purposes of recovering the costs of the projects through the environmental surcharge; (2) approve the revised Rate Schedule ECR to become effective for bills rendered on and after February 1, 2007; and (3) approve the recovery of the overall rate of return requested herein.

Dated: June 23, 2006

Respectfully submitted,

Kendrick R. Riggs
Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202
Telephone: (502) 560-4222

Elizabeth L. Cocanougher
Senior Corporate Attorney
E.ON U.S. Services Inc. for
Louisville Gas and Electric Company
220 West Main Street
Post Office Box 32010
Louisville, Kentucky 40232
Telephone: (502) 627-4850

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 23rd day of June 2006, via overnight delivery, postage prepaid:

Elizabeth E. Blackford
Assistant Attorney General
Office of the Attorney General
Utility & Rate Intervention Office
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601-8204

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

Counsel for Louisville Gas and
Electric Company

Compliance Plan

LOUISVILLE GAS AND ELECTRIC COMPANY

2006 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) Project Cost
18	Fly Ash, NO_x, SO_2, SO_3, Hg and Particulate	Selective Catalytic Reduction, Dry Electrostatic Precipitator, Pulverized Activated Carbon Injection, Hydrated Lime Injection, Fabric Filter Bag House, Wet Flue Gas Desulfurization, Wet Electrostatic Precipitator	Trimble Co. Unit 2	Clean Air Act Amendments (1990), Clean Air Interstate Rule (2005), Clean Air Mercury Rule (2005), Clean Air Visibility Rule (2005)	Title V Permit V-02-043 rev. 2	2010	$43.46 M (E)
19	NO_x/SO_3	Sorbent Injection	Mill Creek Unit 3, Mill Creek Unit 4, Trimble Co. Unit 1	KRS Chapter 224, General Duty Provisions, Clean Air Interstate Rule (2005)	Title V Permit 145-97-TV, Title V Permit V-02-043, rev. 2	2007	$18.66 M (E)
20	Mercury	Mercury Monitors	All Plants	Clean Air Mercury Rule (2005)	to be incorporated into Title V Operating Permits before 2009	2007	$2.84 M (E)
21	Fly Ash and Particulate	Particulate Monitors	Mill Creek Plant	40CFR Part 60, LMAPCD Regulations 6.02, 6.07, 7.01, and 7.06	Title V Permit 145-97-TV	2006	$.84 M (E)
							$65.79

**Sponsored by witness Dodson*

Statutory Notice

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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**

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 gas and electric service in Jefferson County, Kentucky and portions of other counties in the surrounding area within Kentucky.

Pursuant to KRS 278.183, LG&E hereby gives notice to the Commission that, on this 23rd day of June 2006, it files herewith its application for approval of an amended compliance plan for purposes of recovering the costs of new and additional pollution control facilities and to amend its Electric Rate Schedule ECR.

Notice is further given that the proposed effective date for Electric Rate Schedule ECR is February 1, 2007 as applied to bills rendered on and after that same date.

Submitted to the Commission this 23rd day of June 2006.

Respectfully submitted,

Kendrick R. Riggs
Stoll Keenon Ogden PLLC
1700 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202
Telephone: (502) 560-4222

Elizabeth L. Cocanougher
Senior Corporate Attorney
E.ON U.S. Services Inc. for
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4850

Counsel for Louisville Gas and
Electric Company

CERTIFICATE OF SERVICE

The undersigned hereby certifies the original and ten copies of this statutory notice was hand delivered to Elizabeth O'Donnell, Executive Director, Kentucky Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601, and a copy of this statutory notice was delivered via overnight delivery to Elizabeth E. Blackford, Assistant Attorney General, Office of Rate Intervention, 1024 Capital Center Drive, Suite 200, Frankfort, Kentucky 40601; Michael L. Kurtz, Boehm, Kurtz & Lowry, 36 East Seventh Street, Suite 1510, Cincinnati, Ohio 45202 this 23rd day of June 2006.

Counsel for Louisville Gas and
Electric Company

Tariff Sheet with Revision Marks

ECR

Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

To all electric rate schedules

RATE

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

$$CESF = E(m) / R(m) \qquad\qquad MESF = CESF - BESF$$

MESF = Monthly Environmental Surcharge Factor
CESF = Current Environmental Surcharge Factor
BESF = Base Environmental Surcharge Factor

Where 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 as set forth below.

DEFINITIONS

1) For all Plans, $E(m) = [(RB/12)\ (ROR + (ROR - DR)\ (TR / (1 - TR))] + OE - BAS$ T
   Where: T
   a) RB is the Total Environmental Compliance Rate Base. T
   b) ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the T
      overall all 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]. T
   d) TR is the Composite Federal and State Income Tax Rate. T
   e) OE is the Operating Expenses [Depreciation and Amortization Expense, Property Taxes, T
      Insurance 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 Case Nos. 2000-386, 2002-147, 2004-00421 and 2006-00208. T
   f) BAS is the total proceeds from by-product and allowance sales T

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor 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 T
   ending with the current expense month. Base revenue includes the customer, energy and T
   demand charge for each schedule to which this mechanism is applicable and automatic T
   adjustment clause revenues for the Fuel Adjustment Clause, the Demand-Side Management T
   Cost Recovery Mechanism and STOD Program Cost Recovery Factor as applicable for each T
   rate schedule. T

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

Date of Issue: June 23, 2006
Canceling First Revision to Original Sheet No. 72
Issued June 28, 2005

Issued By

John R. McCall, Executive Vice President
General Counsel and Secretary
Louisville, Kentucky

Effective: With Bills Rendered On and After February 1, 2007

Certificate of Notice

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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**

CERTIFICATE OF NOTICE

Pursuant to the Kentucky Public Service Commission's Rules Governing Tariffs effective August 4, 1984, I hereby certify that I am John R. McCall, Executive Vice President, General Counsel and Corporate Secretary, E.ON U.S. Services Inc. for Louisville Gas and Electric Company ("LG&E" or "Company"), a utility furnishing retail electric and gas service within the Commonwealth of Kentucky, which, on the 23rd day of June 2006, filed an application for approval of an amended compliance plan for purposes of recovering the costs of new and additional pollution control facilities and to amend its Electric Rate Schedule ECR as required by KRS 278.183, as follows:

On the 23rd day of June 2006, the same was delivered for exhibition and public inspection at 820 West Broadway Street, Louisville, KY 40202.

That more than twenty (20) customers will be affected by said change by way of an increase in their bills, and that on the 8th day of June 2006, there was delivered to *The Courier-Journal*, a newspaper of general circulation throughout the areas in the Commonwealth of Kentucky in which customers affected reside, for publication therein once a week for three consecutive weeks beginning the week of June 19, 2006, a notice of the filing of LG&E's application, a copy of said notice being attached hereto. 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, Section 8(2)(c).

In addition, Louisville Gas and Electric Company will include a general statement explaining the application in this case with the bills for all Kentucky retail customers during the course of their regular monthly billing cycle beginning on or about June 19, 2006.

Given under my hand this 23rd day of June 2006.

John R. McCall
Executive Vice President, General Counsel
and Corporate Secretary
E.ON U.S. Services Inc. for
LOUISVILLE GAS AND ELECTRIC
COMPANY
220 West Main Street
Louisville, Kentucky 40202

NOTICE TO CUSTOMERS OF LOUISVILLE GAS AND ELECTRIC COMPANY

RECOVERY BY ENVIRONMENTAL SURCHARGE OF LG&E'S 2006 ENVIRONMENTAL COMPLIANCE PLAN

PLEASE TAKE NOTICE that on June 23, 2006, Louisville Gas and Electric Company ("LG&E") will file with the Kentucky Public Service Commission ("Commission") in Case No. 2006-00208, an Application pursuant to Kentucky Revised Statute 278.183 for approval of an amended compliance plan ("LG&E's 2006 Environmental Compliance Plan") for the purpose of recovering the capital costs and operation and maintenance costs associated with new pollution control facilities through an environmental surcharge on customers' bills beginning February 2007, under LG&E's existing rate mechanism known as the environmental cost recovery surcharge or "Electric Rate Schedule ECR."

Federal, state and local environmental regulations require LG&E to continually build and upgrade equipment and/or facilities in order to operate in an environmentally sound manner. Specifically, LG&E is seeking recovery of costs associated with environmental projects necessary for compliance with the Federal Clean Air Act, Clean Air Interstate Rule, Clean Air Mercury Rule, and the Clean Air Visibility Rule. These additional projects primarily relate to particulate matter emissions monitoring, mercury emissions monitoring, Air Quality Control System equipment necessary to operate Trimble County Unit 2 within the approved environmental limitations and sulfur trioxide mitigation on electric generating units which burn high sulfur coal. The total capital cost of these new pollution control facilities is estimated to be $66 million.

The estimated impact on a residential electric customer using 1,000 kilowatt hours per month is expected to be an initial monthly increase of $0.41 for LG&E customers during 2007, with the maximum monthly increase expected to be $0.81 during 2010.

The Environmental Surcharge Application described in this Notice is proposed by LG&E. However, the Public Service Commission may make 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. 2006-00208. 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: Kent W. Blake, Director, State Regulation and Rates. A copy of the Application and testimony will be available for public inspection at LG&E's offices where bills are paid after June 23, 2006.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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**

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Given under my hand this 23rd day of June 2006.

John R. McCall
Executive Vice President, General Counsel
and Corporate Secretary
E.ON U.S. Services Inc. for
LOUISVILLE GAS AND ELECTRIC
COMPANY
220 West Main Street
Louisville, Kentucky 40202

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The estimated impact on a residential electric customer using 1,000 kilowatt hours per month is expected to be an initial monthly increase of $0.41 for LG&E customers during 2007, with the maximum monthly increase expected to be $0.81 during 2010.

The Environmental Surcharge Application described in this Notice is proposed by LG&E. However, the Public Service Commission may make 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.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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**

DIRECT TESTIMONY OF
KENT W. BLAKE
DIRECTOR, STATE REGULATION AND RATES
E.ON U.S. SERVICES INC.

Filed: June 23, 2006

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

A. My name is Kent W. Blake. I am the Director of State Regulation and Rates for E.ON U.S. Services Inc., 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 testified several times including Case Nos. 2004-00426[1] and 2004-00421[2], the Companies' most recent Environmental Cost Recovery applications.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following three exhibits:

(1) Exhibit KWB-1 is the Regulatory Research Associates publication *Regulatory Focus* of April 5, 2006 containing the compilation of allowed returns;

(2) Exhibit KWB-2 contains interest rates showing an upward trend from the timeframe of the last ECR proceeding to the present; and

(3) Exhibit KWB-3 is the Value Line *Quarterly Economic Review* from May 2006 showing interest rate projections.

Q. What is the purpose of your testimony?

A. My testimony provides an overview of the testimony of our other witnesses, presents an overview of LG&E's 2006 Environmental Compliance Plan ("2006 Plan") and

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

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

explains why LG&E is seeking environmental surcharge recovery of its 2006 Plan through its Environmental Cost Recovery ("ECR") Surcharge tariff, beginning in February 2007, including LG&E's request and support for continuing the current 10.50 percent return on common equity. LG&E's 2006 Plan includes LG&E's allocated share of the costs of environmental equipment to be installed on Trimble County Unit 2 ("TC2") and other environmental projects LG&E must construct to continue to remain in compliance with various environmental laws and regulations.

Overview of Application

Q. Would you please provide an overview of the testimony of the witnesses supporting LG&E's application in this proceeding?

A. Yes. In addition to my testimony, LG&E is presenting the testimony of four other witnesses in this case. These witnesses and the subject of their testimony are:

- Sharon L. Dodson, Director of Environmental Affairs, E.ON U.S. Services Inc., presents testimony concerning the environmental regulatory requirements faced by the Companies, including a description of the background surrounding the Clean Air Implementation Rule ("CAIR"), the Clean Air Mercury Rule ("CAMR"), Clean Air Visibility Rule ("CAVR"), and fine particulate emission rules.
- John P. Malloy, Director of Generation Services, E.ON U.S. Services Inc., presents testimony that describes the projects and presents evidence as to the cost effectiveness of the projects in LG&E's 2006 Plan.
- Shannon L. Charnas, Director of Utility Accounting and Reporting, E.ON U.S. Services Inc., presents testimony affirming that none of the costs for

which LG&E is seeking recovery through its Environmental Surcharge tariff are included in base rates and describes the accounting associated with the projects in LG&E's 2006 Plan.

- Robert M. Conroy, Manager of Rates, E.ON U.S. Services Inc., 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.

Q. Did the Commission issue a certificate of public convenience and necessity which includes the pollution control facilities to be built as part of the Trimble County Unit No. 2?

A. Yes. The environmental equipment to be built in connection with the construction of Trimble County Unit 2 is included in the authority of the CCN issued by the Commission in its Order dated November 1, 2005 in Case No. 2004-00507[3].

2006 Environmental Surcharge Plan and Recovery

Q. Is environmental compliance important to LG&E?

A. Yes. Protection of the environment is a major priority for LG&E. LG&E has a long-standing commitment to compliance with all environmental regulations and statutes. Most recently, Vic Staffieri, president, chairman and chief executive of E.ON U.S., the parent company of LG&E, recognized global warming as a real concern and

[3] In the Matter of: *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity, and a Site Compatibility Certificate, for the Expansion of the Trimble County Generating Station.*

committed funds to research at the University of Kentucky addressing affordable ways to capture emissions from power plants.

Q. Is LG&E proposing a 2006 Environmental Surcharge Plan in this proceeding?

A. Yes. The projects in LG&E's 2006 Plan serve LG&E's Cane Run, Mill Creek and Trimble County generating stations, as well as, LG&E's ownership of TC2 which is now under construction. LG&E's 2006 Plan contains four new projects that enable LG&E to comply with the requirements of the CAAA, CAIR, CAMR, CAVR and other environmental regulations that apply to LG&E facilities used for the production of energy from coal. The testimony of Ms. Dodson presents LG&E's evidence concerning the applicable environmental regulatory requirements and shows how the pollution control facilities in the 2006 Plan satisfy LG&E's environmental obligations. LG&E's 2006 Plan is attached as Exhibit JPM-1 to Mr. Malloy's testimony. The testimony of Mr. Malloy presents LG&E's 2006 Plan, describes the need for the new projects in that plan, provides the timeframe for construction, provides evidence as to the cost-effectiveness of the projects and details the estimated capital cost of $66 million for the projects.

Q. What evidence does LG&E present on the accounting for the cost for the 2006 Plan?

A. Ms. Charnas presents testimony to explain LG&E's reporting and accounting for the capital costs and operation and maintenance expenses associated with the pollution control facilities described in Mr. Malloy's testimony and affirms that the environmental compliance costs LG&E proposes to recover through its surcharge are not already in existing rates.

Q. What return on common equity is LG&E currently allowed in its ECR tariff?

A. LG&E is currently allowed a return on equity ("ROE") of 10.50 percent per the Commission's June 20, 2005 Order in Case No. 2004-00421[4].

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

A. The Company is requesting a continuation of the 10.50 percent ROE allowed in Case No. 2004-00421[5]. This level of ROE is still reasonable and is, in fact, conservative under the economic conditions prevailing currently.

Q. On what basis do you say that a 10.50 percent ROE would be reasonable, and even conservative?

A. An examination of (1) allowed returns on common equity for utilities, in general, (2) the recent level and trend in interest rates and (3) the projected course of interest rates shows this to be the case.

According to Regulatory Research Associates *Regulatory Focus* of April 5, 2006, allowed returns for electric utilities and gas utilities in the first quarter of 2006 averaged 10.4 percent and 10.6 percent, respectively. Exhibit KWB-1 contains a complete copy of this publication. For calendar year 2005, electric utilities and gas utilities were both allowed an average return on equity of 10.50 percent. Thus, an allowed return of 10.50 percent for LG&E for ECR purposes is within the mainstream of allowed return for utilities in general. While such awards do not necessarily determine what ROE should be awarded in a case, the Commission has found such awards do "indicate a reasonableness measure for a company's allowed ROE."[6]

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

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

[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*, Case No. 2004-00421, Order, p. 21 (June 20, 2005).

Exhibit KWB-1 shows LG&E's request for continuing the current 10.50% ROE is reasonable when measured by the current authorized ROEs by other commissions.

In addition, these allowed ROEs are consistent with those recently authorized by this Commission in cases involving other investor-owned utilities serving the State of Kentucky. Most recently, on March 14, 2006, the Commission approved a settlement agreement in, *In the Matter of: General Adjustments of Electric Rates of Kentucky Power Company,* Case No. 2005-00341, Appendix A, Settlement Agreement, Paragraph 7, which, among other things, authorized the use of a 10.5% rate of return on equity for environmental surcharge purposes and for accounting for allowance for funds used during construction.

Exhibit KWB-2 shows the level of interest rates for 10- and 20-year Treasury bonds, A-rated utility bonds and Aaa-rated Corporate bonds for the period January 2005-May 2006. As can be seen from Exhibit KWB-2, there has generally been an upward trend in the level of interest rates over this period, with an acceleration in the increase noticeable over the past several months. On a spot basis—comparing May 2006 with June 2005 (when the Commission rendered its Order in the last ECR proceeding)—interest rates are up about one full percentage point. As shown on the bottom of Exhibit KWB-2, on a six-month average basis, interest rates are up roughly 30-40 basis points.

Projections of interest rates show that the upward trend in interest rates is forecast to continue. For example, *The Value Line Quarterly Economic Review* of May 26, 2006 shows that 10-year and long-term Treasury securities are projected to rise to the level of 5.3 percent and 5.5 percent, respectively, by 2008. AAA-rated Corporate Bonds are projected to increase to 6.4 percent by that time period. A complete copy of this Value Line publication is attached as Exhibit KWB-3 to my testimony.

Based on the above data and comparisons, a continuation of the 10.50 percent allowed ROE for ECR purposes is reasonable, and even conservative.

Q. How does LG&E propose to recover the cost of the pollution control projects in its 2006 Plan?

A. LG&E proposes to recover the cost of the pollution control projects in its 2006 Plan through LG&E's Electric Rate Schedule ECR filed with this application and proposed to be effective for bills rendered on and after February 1, 2007. The testimony of Mr. Conroy explains how the surcharge for the 2006 Plan will be calculated and billed under LG&E's proposed revised ECR Tariff. Mr. Conroy's testimony explains the reasons for the 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.

Q. What action should the Commission take regarding this application?

A. The Commission should approve LG&E's 2006 Plan and application for cost recovery of its compliance costs through its Electric Rate Schedule ECR tariff beginning with bills rendered on and after February 1, 2007.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

The undersigned, **Kent W. Blake**, being duly sworn, deposes and says he is Director, State Regulation and Rates for E.ON U.S. Services Inc., 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.

Kent W Blake

KENT W. BLAKE

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of June 2006.

Tammy J. Elzy (SEAL)

Notary Public

My Commission Expires:

TAMMY J. ELZY
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
My Commission Expires Nov. 9, 2006

APPENDIX A

Kent W. Blake

Director, State Regulation and Rates
E.ON U.S. Services Inc.
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40202
(502) 627-2573

Education

University of Kentucky, B.S. in Accounting, 1988
Certified Public Accountant, Kentucky, 1991
Multiple industry and executive development programs

Previous Positions

LG&E Energy LLC, Louisville, Kentucky
- 2003 (Sept) – 2004 (Oct) – Director, Regulatory Initiatives
- 2003 (Feb) – 2003 (Sept) – Director, Business Development
- 2002 (Aug) – 2003 (Feb) – Director, Finance and Business Analysis

Mirant Corporation (f.k.a. Southern Company Energy Marketing)
- 2002 (Feb-Aug) – Senior Director, Applications Development
- 2000-2002 – Director, Systems Integration
- 1998-2000 – Trading Controller

LG&E Energy Corp.
- 1997-1998 – Director, Corporate Accounting and Trading Controls

Arthur Andersen LLP
- 1992-1997 – Manager, Audit and Business Advisory Services
- 1990-1992 – Senior Auditor
- 1988-1990 – Audit Staff

Exhibit KWB-1 – Regulatory Research Associates publication *Regulatory Focus*

Regulatory Study
April 5, 2006

MAJOR RATE CASE DECISIONS--JANUARY-MARCH 2006

For the first three months of 2006, the average electric equity return authorization by state commissions was 10.38% (three determinations), compared to the 10.54% average in calendar-2005. The average gas equity return authorization for the first quarter of 2006 was 10.63% (six determinations), compared to the 10.46% average in calendar-2005. During the first quarter of 2006, there were no telecommunications equity return authorizations.

After reaching a low in the late-1990's and early-2000's, the number of equity return determinations for energy companies increased somewhat beginning in 2002 and reached a ten-year high in 2005. Relatively low inflation and interest rates, competitive pressures, technological improvements, the use of settlements that do not specify return parameters, and a reduced number of companies due to mergers may prevent the number of yearly determinations from substantially increasing further. However, increased costs and the need for generation and delivery system infrastructure upgrades and expansion at many companies argue for at least a modest increase in the number of cases to be filed and decided over the next several years. We also note that electric industry restructuring in many states has led to the unbundling of rates, with state commissions authorizing revenue requirement and return parameters for transmission and/or distribution operations only (which we footnote in our chronology table), complicating data comparability. The tables included in this study are extensions of those contained in the January 12, 2006 Regulatory Study entitled *Major Rate Case Decisions--January 2004-December 2005--Supplemental Study*. Refer to that report for information concerning individual rate case decisions that were rendered in 2004 and 2005.

The table on page 2 shows annual average equity returns authorized since 1996, and by quarter since 2000, in major electric, gas, and telecommunications rate decisions, followed by the number of determinations during each period. The tables on page 3 present the composite industry data for items in the chronology of this and earlier reports, summarized annually since 1996, and quarterly for the most recent nine quarters. The individual electric, gas, and telecommunications cases decided in the first three months of 2006 are listed on pages 4 and 5, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return (ROR), return on equity (ROE), and percentage of common equity in the adopted capital structure. Next we show the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base, and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Summary data for 2005 is also included for comparative purposes. A case is generally considered "major" if the rate change initially requested was $5 million or greater, or the authorized rate change was at least $3 million. Gas rate requests that are considered in conjunction with major electric requests are recorded and reported as individual cases, regardless of size. Fuel adjustment clause rate changes are not reflected in this study.

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Average Equity Returns Authorized January 1988 - March 1998

(Return Percent - No. of Observations)

	Period	Electric Utilities	Gas Utilities	Telephone Utilities
1988	Full Year	12.79 (33)	12.85 (31)	13.13 (13)
1989	Full Year	12.97 (27)	12.88 (31)	12.97 (15)
1990	Full Year	12.70 (44)	12.67 (31)	12.91 (9)
1991	Full Year	12.55 (45)	12.46 (35)	12.89 (16)
1992	1st Quarter	12.37 (12)	12.42 (5)	12.25 (2)
	2nd Quarter	11.83 (12)	11.98 (3)	--- (0)
	3rd Quarter	12.03 (8)	11.87 (5)	12.35 (2)
	4th Quarter	12.12 (16)	11.94 (16)	12.23 (3)
1992	Full Year	12.09 (48)	12.01 (29)	12.27 (7)
1993	1st Quarter	11.84 (7)	11.75 (4)	12.20 (1)
	2nd Quarter	11.64 (9)	11.71 (6)	12.36 (4)
	3rd Quarter	11.15 (6)	11.39 (13)	11.65 (1)
	4th Quarter	11.07 (10)	11.15 (22)	11.45 (6)
1993	Full Year	11.41 (32)	11.35 (45)	11.83 (12)
1994	1st Quarter	11.20 (10)	11.12 (5)	11.05 (3)
	2nd Quarter	11.13 (5)	10.81 (5)	12.46 (3)
	3rd Quarter	12.75 (1)	10.95 (2)	---- (0)
	4th Quarter	11.41 (15)	11.64 (16)	11.88 (5)
1994	Full Year	11.34 (31)	11.35 (28)	11.81 (11)
1995	1st Quarter	11.96 (8)	--- (0)	--- (0)
	2nd Quarter	11.36 (9)	11.00 (1)	11.84 (4)
	3rd Quarter	11.33 (6)	11.07 (3)	12.50 (1)
	4th Quarter	11.53 (10)	11.56 (12)	12.25 (3)
1995	Full Year	11.55 (33)	11.43 (16)	12.08 (8)
1996	1st Quarter	11.28 (2)	11.45 (2)	11.70 (2)
	2nd Quarter	11.46 (9)	10.88 (6)	11.30 (1)
	3rd Quarter	10.76 (3)	11.25 (2)	12.25 (1)
	4th Quarter	11.58 (8)	11.32 (10)	--- (0)
1996	Full Year	11.39 (22)	11.19 (20)	11.74 (4)
1997	1st Quarter	11.30 (4)	11.31 (7)	11.80 (1)
	2nd Quarter	11.62 (3)	11.70 (1)	11.60 (1)
	3rd Quarter	12.00 (1)	12.00 (1)	11.70 (1)
	4th Quarter	11.08 (4)	11.01 (5)	11.35 (2)
1997	Full Year	11.36 (12)	11.28 (14)	11.56 (5)
1998	1st Quarter	11.49 (5)	12.20 (1)	11.30 (1)

Electric Utilities--Summary Table*

	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1996	Full Year	9.21 (20)	11.39 (22)	44.34 (20)	-5.6 (38)
1997	Full Year	9.16 (12)	11.40 (11)	48.79 (11)	-553.3 (33)
1998	Full Year	9.44 (9)	11.66 (10)	46.14 (8)	-429.3 (31)
1999	Full Year	8.81 (18)	10.77 (20)	45.08 (17)	-1,683.8 (30)
2000	Full Year	9.20 (12)	11.43 (12)	48.85 (12)	-291.4 (34)
2001	Full Year	8.93 (15)	11.09 (18)	47.20 (13)	14.2 (21)
2002	Full Year	8.72 (20)	11.16 (22)	46.27 (19)	-475.4 (24)
2003	Full Year	8.86 (20)	10.97 (22)	49.41 (19)	313.8 (22)
2004	1st Quarter	8.94 (3)	11.00 (3)	44.94 (3)	-716.4 (4)
	2nd Quarter	7.88 (6)	10.54 (6)	45.59 (6)	641.8 (11)
	3rd Quarter	9.01 (2)	10.33 (2)	45.05 (2)	119.4 (4)
	4th Quarter	8.55 (7)	10.91 (8)	49.64 (6)	1,047.8 (11)
2004	Full Year	8.44 (18)	10.75 (19)	46.84 (17)	1,092.6 (30)
2005	1st Quarter	8.57 (6)	10.51 (7)	44.55 (7)	482.1 (8)
	2nd Quarter	8.27 (5)	10.05 (7)	48.30 (5)	180.2 (9)
	3rd Quarter	7.78 (4)	10.84 (4)	43.58 (4)	40.2 (5)
	4th Quarter	8.37 (11)	10.75 (11)	48.55 (11)	671.2 (14)
2005	Full Year	8.31 (26)	10.54 (29)	46.73 (27)	1,373.7 (36)
2006	1st Quarter	8.13 (3)	10.38 (3)	50.25 (3)	439.0 (9)

Gas Utilities--Summary Table*

1996	Full Year	9.25 (23)	11.19 (20)	47.69 (19)	193.4 (34)
1997	Full Year	9.13 (13)	11.29 (13)	47.78 (11)	-82.5 (21)
1998	Full Year	9.46 (10)	11.51 (10)	49.50 (10)	93.9 (20)
1999	Full Year	8.86 (9)	10.66 (9)	49.06 (9)	51.0 (14)
2000	Full Year	9.33 (13)	11.39 (12)	48.59 (12)	135.9 (20)
2001	Full Year	8.51 (6)	10.95 (7)	43.96 (5)	114.0 (11)
2002	Full Year	8.80 (20)	11.03 (21)	48.29 (18)	303.6 (26)
2003	Full Year	8.75 (22)	10.99 (25)	49.93 (22)	260.1 (30)
2004	1st Quarter	8.52 (4)	11.10 (4)	45.61 (4)	56.3 (6)
	2nd Quarter	8.21 (3)	10.25 (2)	46.90 (2)	121.7 (9)
	3rd Quarter	8.27 (8)	10.37 (8)	42.92 (8)	113.4 (8)
	4th Quarter	8.40 (6)	10.66 (6)	49.72 (6)	12.1 (8)
2004	Full Year	8.34 (21)	10.59 (20)	45.90 (20)	303.5 (31)
2005	1st Quarter	8.19 (3)	10.65 (2)	43.00 (1)	50.8 (4)
	2nd Quarter	8.17 (5)	10.54 (5)	47.69 (4)	99.5 (6)
	3rd Quarter	8.15 (6)	10.47 (5)	49.54 (5)	75.3 (7)
	4th Quarter	8.33 (15)	10.40 (14)	49.03 (14)	232.8 (17)
2005	Full Year	8.25 (29)	10.46 (26)	48.66 (24)	458.4 (34)
2006	1st Quarter	8.62 (6)	10.63 (6)	51.18 (6)	138.7 (6)

Telephone Utilities--Summary Table*

1996	Full Year	9.65 (2)	11.74 (4)	56.00 (2)	-348.2 (11)
1997	Full Year	9.57 (5)	11.56 (5)	55.84 (5)	-154.4 (7)
1998	Full Year	9.37 (1)	11.30 (1)	52.00 (1)	-323.3 (13)
1999	Full Year	11.34 (1)	13.00 (1)	66.90 (1)	-570.1 (19)
2000	Full Year	9.52 (2)	11.38 (2)	56.59 (2)	-390.4 (14)
2001	Full Year	9.61 (1)	--- (0)	--- (0)	-130.0 (8)
2002	Full Year	--- (0)	--- (0)	--- (0)	7.7 (4)
2003	Full Year	--- (0)	--- (0)	--- (0)	-62.6 (2)
2004	1st Quarter	8.02 (1)	10.00 (1)	44.18 (1)	3.1 (1)
	2nd Quarter	--- (0)	--- (0)	--- (0)	--- (0)
	3rd Quarter	--- (0)	--- (0)	--- (0)	--- (0)
	4th Quarter	--- (0)	--- (0)	--- (0)	--- (0)
2004	Full Year	8.02 (1)	10.00 (1)	44.18 (1)	3.1 (1)
2005	1st Quarter	--- (0)	--- (0)	--- (0)	--- (0)
	2nd Quarter	--- (0)	--- (0)	--- (0)	71.9 (2)
	3rd Quarter	8.72 (1)	10.50 (1)	54.00 (1)	-8.2 (1)
	4th Quarter	--- (0)	--- (0)	--- (0)	--- (0)
2005	Full Year	8.72 (1)	10.50 (1)	54.00 (1)	63.7 (3)
2006	1st Quarter	--- (0)	--- (0)	--- (0)	--- (0)

* Number of observations in each period indicated in parentheses.

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
	ELECTRIC UTILITY DECISIONS					
2005	***FULL-YEAR: AVERAGES/TOTAL***	**8.31**	**10.54**	**46.73**		**1373.7**
	MEDIAN	**8.08**	**10.25**	**44.59**		**---**
	OBSERVATIONS	**26**	**29**	**27**		**36**
1/5/06	Northern States Power (WI)	8.94 (G)	11.00	53.66	12/06-A	43.4
1/25/06	Wisconsin Electric Power (WI)	---	---	---	---	229.7 (1)
1/27/06	United Illuminating (CT)	6.88 (2)	9.75	48.00	12/04-A	35.6 (Di,Z,2)
2/22/06	PacifiCorp (WY)	---	---	---	---	25.0 (B,Z)
2/23/06	Aquila Networks-MPS (MO)	---	---	---	---	22.4 (B)
2/23/06	Aquila Networks-L&P (MO)	---	---	---	---	3.9 (B)
3/3/06	Interstate Power and Light (MN)	8.58	10.39	49.10	12/04-A	1.2 (I,B)
3/14/06	Kentucky Power (KY)	---	---	---	---	41.0 (B)
3/29/06	Entergy Gulf States (LA)	---	---	---	---	36.8 (I,B)
2006	***1ST QUARTER: AVERAGES/TOTAL***	**8.13**	**10.38**	**50.25**		**439.0**
	MEDIAN	**8.58**	**10.39**	**49.10**		**---**
	OBSERVATIONS	**3**	**3**	**3**		**9**
	GAS UTILITY DECISIONS					
2005	***FULL-YEAR: AVERAGES/TOTAL***	**8.25**	**10.46**	**48.66**		**458.4**
	MEDIAN	**8.42**	**10.23**	**47.14**		**---**
	OBSERVATIONS	**29**	**26**	**24**		**34**
1/5/06	Northern States Power (WI)	8.94 (G)	11.00	53.66	12/06-A	3.9
1/25/06	Wisconsin Electric Power (WI)	8.52 (G)	11.20	56.34	12/06-A	21.4
1/25/06	Wisconsin Gas (WI)	8.29 (G)	11.20	50.20	12/06-A	38.7
2/3/06	Public Service of Colorado (CO)	8.70	10.50	55.49	12/04-A	22.5 (B)
2/23/06	Southwest Gas (AZ)	8.40	9.50	40.00 (Hy)	8/04-YE	49.3
3/1/06	Aquila (IA)	8.88	10.40 (E)	51.39	12/04-A	2.9 (I,B)
2006	***1ST QUARTER: AVERAGES/TOTAL***	**8.62**	**10.63**	**51.18**		**138.7**
	MEDIAN	**8.61**	**10.75**	**52.53**		**---**
	OBSERVATIONS	**6**	**6**	**6**		**6**
	TELEPHONE UTILITY DECISIONS					
2005	***FULL-YEAR: AVERAGES/TOTAL***	**8.72**	**10.50**	**54.00**		**63.7**
	MEDIAN	**8.72**	**10.50**	**54.00**		**---**
	OBSERVATIONS	**1**	**1**	**1**		**3**
2006	***1ST QUARTER: AVERAGES/TOTAL***	**---**	**---**	**---**		**---**
	MEDIAN	**---**	**---**	**---**		**---**
	OBSERVATIONS	**0**	**0**	**0**		**0**

FOOTNOTES

A- Average
B- Order followed stipulation or settlement by the parties. Decision particulars not necssarily precedent-setting or specifically adopted by the regulatory body.
Di- Rate change applicable to electric distribution rates only.
E- Estimated
G- Return on capital
Hy- Hypothetical capital structure utilized
I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.
YE- Year-end
Z- Rate change implemented in multiple steps.
* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) The electric rate increase was not supported by a traditional cost-of-service analysis, but reflected recovery of certain specific costs.
(2) Indicated rate increase to be phased-in over four years, with a 6.88% ROR authorized for 2006, 6.89% for 2007, 7.09% for 2008, and 7.48% for 2009.

Dennis Sperduto

Exhibit KWB-2 – Interest Rates

INTEREST RATES
January 2005 - May 2006

		10- Year Treasury Bond Yields (1)	20- Year Treasury Bond Yields (2)	A Utility Bond Yields (3)	Aaa Corporate Bond Yields (4)
2005	January	4.22 %	4.77 %	5.78 %	5.36 %
	February	4.17	4.61	5.61	5.20
	March	4.50	4.89	5.83	5.40
	April	4.34	4.75	5.64	5.33
	May	4.14	4.56	5.53	5.15
	June	4.00	4.35	5.40	4.96
	July	4.18	4.48	5.51	5.06
	August	4.26	4.53	5.50	5.09
	September	4.20	4.51	5.52	5.13
	October	4.46	4.74	5.79	5.34
	November	4.54	4.83	5.88	5.42
	December	4.47	4.73	5.80	5.38
2006	January	4.42	4.65	5.75	5.29
	February	4.57	4.73	5.82	5.35
	March	4.72	4.91	5.98	5.52
	April	4.99	5.22	6.29	5.84
	May	5.10	5.34	6.40	5.95
6-Month Average Ended:					
	June 2005	4.23	4.66	5.63	5.23
	May 2006	4.71	4.93	6.01	5.56

Source: Cols. (1)&(2) - Federal Reserve Statistical Release.
Cols. (3)&(4) - Mergent *Bond Record* and Moody's website.

Exhibit KWB-3 – Value Line *Quarterly Economic Review*

THE VALUE LINE Investment Survey®

PAGES 1107-1122
File in page order in the *Selection & Opinion* binder.

PART 2 — *Selection & Opinion* — MAY 26, 2006

Dear Subscriber,

As part of our ongoing efforts to keep *The Value Line Investment Survey* the most valuable investment resource for our subscribers, the entire service is now being released on the Web at 8:00AM Eastern time on Thursday. You can find it at www.valueline.com by using your user name and password. Supplements will be available as appropriate. We look forward to continuing to provide you with the most accurate and innovative research tools available.

Faithfully, Jean Bernhard Buttner

The Quarterly Economic Review

In This Issue

The *Selection & Opinion* Index appears on page 1250 (March 3, 2006).

In Three Parts: Part 1 is the Summary & Index. This is Part 2, Selection & Opinion. Part 3 is Ratings & Reports. Volume LXI, Number 39.

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See back cover for important disclosures.

ECONOMIC AND STOCK MARKET COMMENTARY

Three months ago, in our last "Quarterly Economic Review," we observed that it looked as though economic growth would "pick up nicely" in the first quarter, which, in fact, it did. However, the unfolding business strength was greater than we expected, with the nation's gross domestic product increasing by a vigorous 4.8%. Contributing to this sharp improvement, versus the prior period's lackluster 1.7% rate of GDP growth, were significant increases in consumer expenditures, U.S. exports, government spending (especially on national defense), and nonresidential construction. On the other hand, the growth in residential building slowed a bit, although such activity did not decline as bearish forecasters had warned might be the case.

We think the momentum built up in the opening quarter will remain largely in place during the current period. Our expectation is that this early 2006 strength will ease only modestly, with the economy growing by a still solid 3.3%-3.5%. That's in line with the growth we had forecast three months ago. Once again, the capital goods sector should lead the way, with solid growth across much of Europe and Asia helping to increase demand for U.S. exports. Continuing gains in personal income, meanwhile, should lead to an additional uptick in personal consumption expenditures, although it is arguable just how much longer consumers will retain their spending pace given near-record oil prices. The lone discordant note is now being sounded by the housing market, where construction activity declined further in April. Sales of new and existing homes also appear to be headed lower.

Some further slowing in the pace of business activity is likely to evolve later this year and in 2007. The major risk in the second half of 2006, and next year as well, involves the once-frothy U.S.

Continued on page 1110

VALUE LINE FORECAST FOR THE U.S. ECONOMY

Statistical Summary for 2005-2007

	2005:4	2006:1	2006:2	2006:3	2006:4	2007:1	2007:2	2007:3	2006	2007
GDP AND OTHER KEY MEASURES										
Real Gross Domestic Product	11248	*11381*	*11477*	*11568*	*11653*	*11731*	*11818*	*11909*	*11520*	*11865*
Total Light Vehicle Sales (Mill. Units)	15 8	*16.9*	*16.5*	*16.4*	*16.2*	*16.0*	*16.3*	*16.6*	*16.5*	*16.4*
Housing Starts (Million Units)	2 06	*2.13*	*1.88*	*1.85*	*1.83*	*1.80*	*1.78*	*1.78*	*1.92*	*1.79*
Corporate Economic Profits ($Bill.)	1293 0	*1479.0*	*1537.0*	*1461.0*	*1396.0*	*1538.0*	*1583.0*	*1534.0*	*1468.0*	*1527.0*
ANNUALIZED RATES OF CHANGE										
Gross Domestic Product (Real)	1 7	*4.8*	*3.4*	*3.2*	*3.0*	*2.7*	*3.0*	*3.1*	*3.5*	*3.0*
GDP Deflator	3 5	*3.3*	*3.4*	*2.3*	*2.0*	*2.1*	*2.1*	*2.2*	*2.8*	*2.2*
CPI-All Urban Consumers	3 2	*2.2*	*4.0*	*2.7*	*2.0*	*2.3*	*2.3*	*2.5*	*2.7*	*2.4*
AVERAGE FOR THE PERIOD										
National Unemployment Rate	4 9	*4.7*	*4.7*	*4.7*	*4.7*	*4.8*	*4.8*	*4.9*	*4.7*	*4.9*
Prime Rate	7 0	*7.4*	*7.9*	*8.3*	*8.3*	*8.3*	*8.1*	*7.8*	*8.0*	*8.0*
10-Year Treasury Note Rate	4 5	*4.6*	*5.1*	*5.2*	*5.2*	*5.2*	*5.1*	*5.1*	*5.0*	*5.1*

Value Line Forecast for the U.S. Economy

	ACTUAL	ESTIMATED						
	2005:4	2006:1	2006:2	2006:3	2006:4	2007:1	2007:2	2007:3
GROSS DOMESTIC PRODUCT AND ITS COMPONENTS (2000 CHAIN WEIGHTED $) BILLIONS OF DOLLARS								
Final Sales	11208	11355	11445	11530	11607	11681	11759	11844
Total Consumption	7925	8032	8092	8152	8210	8267	8328	8390
Nonresidential Fixed Investment	1320	1365	1398	1432	1459	1477	1495	1517
Structures	256	261	267	274	280	282	285	289
Equipment & Software	1081	1122	1149	1174	1194	1209	1224	1242
Residential Fixed Investment	614	618	613	599	583	571	564	558
Exports	1218	1253	1268	1299	1329	1358	1386	1415
Imports	1873	1931	1931	1963	1989	2007	2028	2045
Federal Government	745	764	756	760	761	763	764	766
State & Local Governments	1249	1249	1250	1255	1261	1270	1277	1282
Gross Domestic Product	12766	13021	13236	13392	13535	13699	13853	14011
Real GDP (2000 Chain Weighted $)	11248	11381	11477	11568	11653	11731	11818	11909
PRICES AND WAGES-ANNUAL RATES OF CHANGE								
GDP Deflator	3.5	3.3	3.4	2.3	2.0	2.1	2.1	2.2
CPI-All Urban Consumers	3.2	2.2	4.0	2.7	2.0	2.3	2.3	2.5
PPI-Finished Goods	7.3	-0.7	4.5	2.3	1.7	1.5	1.8	1.8
Employment Cost Index—Total Comp	2.8	2.4	3.5	3.5	3.5	3.6	3.5	3.3
Productivity	-0.3	3.2	2.5	2.0	2.0	1.5	1.8	2.0
PRODUCTION AND OTHER KEY MEASURES								
Industrial Prod (% Change, Annualized)	5.3	4.5	6.0	4.0	3.0	2.5	2.5	2.7
Factory Operating Rate (%)	79.8	80.4	81.0	80.5	80.4	80.3	80.2	80.0
Inventory Change (2000 Chain Weighted $)	43.0	25.7	32.0	38.0	47.0	50.0	59.0	65.0
Housing Starts (Mill. Units)	2.06	2.13	1.88	1.85	1.83	1.80	1.78	1.78
Existing House Sales (Mill. Units)	6.94	6.80	6.65	6.50	6.20	6.10	6.10	6.00
Total Light Vehicle Sales (Mill. Units)	15.8	16.9	16.5	16.4	16.2	16.0	16.3	16.6
National Unemployment Rate (%)	4.9	4.7	4.7	4.7	4.7	4.8	4.8	4.9
Federal Budget Surplus (Unified, FY, $Bill)	-119.3	-183.4	85.0	-90.0	-100.0	-150.0	50.0	-55.0
Price of Oil ($Bbl., U.S. Refiners' Cost)	53.94	55.97	63.75	64.65	61.25	61.25	59.50	60.00
MONEY AND INTEREST RATES								
3-Month Treasury Bill Rate (%)	3.8	4.4	4.8	5.0	5.0	5.0	4.9	4.7
Federal Funds Rate (%)	4.0	4.5	4.9	5.3	5.3	5.3	5.2	4.9
10-Year Treasury Note Rate (%)	4.5	4.6	5.1	5.2	5.2	5.2	5.1	5.1
Long-Term Treasury Bond Rate (%)	4.7	4.6	5.3	5.4	5.4	5.4	5.3	5.3
AAA Corporate Bond Rate (%)	5.4	5.4	6.0	6.2	6.2	6.2	6.1	6.1
Prime Rate (%)	7.0	7.4	7.9	8.3	8.3	8.3	8.1	7.8
INCOMES								
Personal Income (Annualized % Change)	9.4	6.2	6.5	6.0	5.8	5.8	5.5	5.3
Real Disp. Inc. (Annualized % Change)	6.7	3.2	3.0	4.0	4.0	3.8	3.8	3.6
Personal Savings Rate (%)	-0.2	-0.7	-0.5	-0.5	-0.2	0.1	0.2	0.4
Corporate Economic Profits (Annualized $Bill)	1293.0	1479.0	1537.0	1461.0	1396.0	1538.0	1583.0	1534.0
Yr-to-Yr % Change	15.7	21.3	14.0	13.0	8.0	4.0	3.0	5.0
COMPOSITION OF REAL GDP-ANNUAL RATES OF CHANGE								
Gross Domestic Product	1.7	4.8	3.4	3.2	3.0	2.7	3.0	3.1
Final Sales	-0.2	5.4	3.2	3.0	2.7	2.6	2.7	2.9
Total Consumption	0.9	5.5	3.0	3.0	2.9	2.8	3.0	3.0
Nonresidential Fixed Investment	4.5	14.3	10.0	10.0	8.0	5.0	5.0	6.0
Structures	3.1	8.6	9.0	12.0	9.0	3.0	4.0	5.0
Equipment & Software	5.0	16.4	10.0	9.0	7.0	5.0	5.0	6.0
Residential Fixed Investment	2.8	2.6	-3.0	-9.0	-10.0	-8.0	-5.0	-4.0
Exports	5.0	12.1	5.0	10.0	9.6	9.0	8.6	8.6
Imports	12.1	13.0	-0.1	6.9	5.3	3.8	4.3	3.3
Federal Government	-2.6	10.8	-3.9	1.7	1.0	0.9	0.6	0.6
State & Local Governments	0.3	0.0	0.4	1.5	2.0	2.8	2.3	1.5

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Value Line Forecast for the U.S. Economy

	ACTUAL					ESTIMATED				
	2001	2002	2003	2004	2005	**2006**	**2007**	**2008**	**2009**	**2010**
GROSS DOMESTIC PRODUCT AND ITS COMPONENTS (2000 CHAIN WEIGHTED $) BILLIONS OF DOLLARS										
Final Sales	9921	10036	10304	10702	11113	*11484*	*11804*	*12158*	*12547*	*12974*
Total Consumption	6910	7099	7306	7589	7857	*8121*	*8360*	*8611*	*8878*	*9171*
Nonresidential Fixed Investment	1180	1072	1085	1187	1289	*1413*	*1507*	*1583*	*1662*	*1778*
Structures	306	254	243	248	253	*271*	*287*	*296*	*308*	*323*
Equipment & Software	874	820	847	948	1051	*1160*	*1233*	*1295*	*1373*	*1483*
Residential Fixed Investment	448	470	509	562	602	*603*	*562*	*551*	*557*	*573*
Exports	1037	1013	1031	1118	1195	*1287*	*1401*	*1539*	*1683*	*1811*
Imports	1436	1485	1553	1719	1828	*1953*	*2038*	*2111*	*2225*	*2348*
Federal Government	601	643	688	724	740	*760*	*765*	*772*	*777*	*786*
State & Local Governments	1179	1216	1223	1228	1246	*1254*	*1279*	*1296*	*1321*	*1339*
Gross Domestic Product	10128	10470	10971	11734	12487	*13296*	*13935*	*14614*	*15369*	*16194*
Real GDP (2000 Chain Weighted $)	9891	10049	10321	10756	11135	*11520*	*11865*	*12233*	*12637*	*13079*
PRICES AND WAGES-ANNUAL RATES OF CHANGE										
GDP Deflator	2.4	1.7	2.0	2.6	2.8	*2.8*	*2.2*	*2.0*	*2.1*	*2.2*
CPI-All Urban Consumers	2.8	1.6	2.3	2.7	3.4	*2.7*	*2.4*	*2.2*	*2.3*	*2.5*
PPI-Finished Goods	1.9	-1.3	3.2	3.6	4.9	*2.0*	*1.7*	*1.3*	*1.5*	*2.0*
Employment Cost Index—Total Comp	4.1	3.8	4.0	3.9	3.1	*3.2*	*3.4*	*3.3*	*3.4*	*3.5*
Productivity	2.2	4.3	3.8	3.4	2.7	*2.4*	*1.8*	*2.0*	*2.3*	*2.5*
PRODUCTION AND OTHER KEY MEASURES										
Industrial Prod. (% Change)	-3.4	-0.3	0.0	4.1	3.2	*4.4*	*2.7*	*2.5*	*2.7*	*3.0*
Factory Operating Rate (%)	75.4	73.5	73.7	76.7	78.9	*80.6*	*80.1*	*79.5*	*80.0*	*80.5*
Inventory Change (2000 Chain Weighted $)	-31.7	15.2	15.4	49.9	25.0	*36.0*	*61.0*	*75.0*	*90.0*	*105.0*
Housing Starts (Mill. Units)	1.60	1.71	1.85	1.95	2.07	*1.92*	*1.79*	*1.75*	*1.73*	*1.80*
Existing House Sales (Mill. Units)	5.29	5.65	6.17	6.72	7.06	*6.54*	*6.05*	*6.00*	*6.05*	*6.10*
Total Light Vehicle Sales (Mill. Units)	17.1	16.8	16.6	16.9	16.9	*16.5*	*16.4*	*16.7*	*17.0*	*17.5*
National Unemployment Rate (%)	4.8	5.8	6.0	5.5	5.1	*4.7*	*4.9*	*4.8*	*4.7*	*4.8*
Federal Budget Surplus (Unified, FY, $Bill)	127.3	-157.8	-377.0	-413.0	-318.0	*-310.0*	*-260.0*	*-315.0*	*-295.0*	*-280.0*
Price of Oil ($Bbl., U.S. Refiners' Cost)	22.95	24.00	28.60	36.91	50.31	*61.50*	*60.00*	*56.35*	*50.75*	*45.00*
MONEY AND INTEREST RATES										
3-Month Treasury Bill Rate (%)	3.4	1.6	1.0	1.4	3.1	*4.8*	*4.8*	*4.6*	*4.7*	*4.8*
Federal Funds Rate (%)	3.9	1.7	1.1	1.4	3.2	*5.0*	*5.0*	*4.8*	*5.0*	*5.2*
10-Year Treasury Note Rate (%)	5.0	4.6	4.0	4.3	4.3	*5.0*	*5.1*	*5.3*	*5.4*	*5.5*
Long-Term Treasury Bond Rate (%)	5.5	5.4	5.0	5.1	4.6	*5.2*	*5.3*	*5.5*	*5.6*	*5.8*
AAA Corporate Bond Rate (%)	7.1	6.5	5.7	5.6	5.2	*6.0*	*6.1*	*6.4*	*6.6*	*6.6*
Prime Rate (%)	6.9	4.7	4.1	4.3	6.2	*8.0*	*8.0*	*7.8*	*7.9*	*8.0*
INCOMES										
Personal Income (% Change)	3.5	1.8	3.2	5.9	5.5	*6.1*	*5.5*	*5.6*	*5.7*	*5.8*
Real Disp. Inc. (% Change)	1.9	3.1	2.4	3.4	1.5	*3.5*	*3.7*	*3.7*	*3.8*	*3.8*
Personal Savings Rate (%)	1.8	2.4	2.1	1.7	-0.4	*-0.5*	*0.3*	*0.8*	*1.0*	*1.2*
Corporate Economic Profits ($Bill)	767.0	886.0	1032.0	1162.0	1352.0	*1468.0*	*1527.0*	*1603.0*	*1715.0*	*1852.0*
Yr-to-Yr % Change	-6.2	15.5	16.4	12.6	16.4	*8.6*	*4.0*	*5.0*	*7.0*	*8.0*
COMPOSITION OF REAL GDP-ANNUAL RATES OF CHANGE										
Gross Domestic Product	0.8	1.6	2.7	4.2	3.5	*3.5*	*3.0*	*3.1*	*3.3*	*3.5*
Final Sales	1.6	1.2	2.7	3.9	3.8	*3.3*	*2.8*	*3.0*	*3.2*	*3.4*
Total Consumption	2.5	2.7	2.9	3.9	3.5	*3.4*	*2.9*	*3.0*	*3.1*	*3.3*
Nonresidential Fixed Investment	-4.2	-9.2	1.2	9.4	8.6	*9.7*	*6.6*	*5.0*	*5.0*	*7.0*
Structures	-2.2	-17.0	-4.3	2.2	2.0	*7.0*	*6.1*	*3.0*	*4.0*	*5.0*
Equipment & Software	-4.9	-6.2	3.3	11.9	10.9	*10.4*	*6.3*	*5.0*	*6.0*	*8.0*
Residential Fixed Investment	0.2	4.9	8.3	10.3	7.1	*0.2*	*-6.8*	*-2.0*	*1.0*	*3.0*
Exports	-5.4	-2.3	1.8	8.4	6.9	*7.7*	*8.8*	*9.9*	*9.3*	*7.6*
Imports	-2.7	3.4	4.6	10.7	6.3	*6.9*	*4.3*	*3.6*	*5.4*	*5.5*
Federal Government	3.8	7.0	7.0	5.2	2.3	*2.8*	*0.6*	*0.9*	*0.7*	*1.1*
State & Local Governments	3.1	3.1	0.6	0.4	1.5	*0.6*	*2.0*	*1.3*	*1.9*	*1.4*

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The Quarterly Economic Review

Continued from cover page

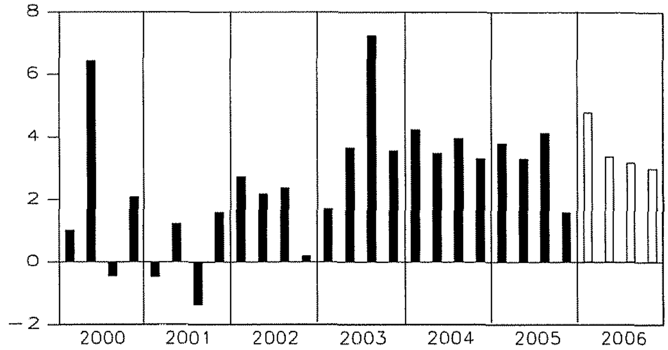
housing market, where a collapse, while unlikely, can't be totally ruled out. High real estate prices and rising mortgage rates are reducing housing affordability for many Americans. The higher cost of heating and cooling one's home isn't helping matters. Our sense is that stabilizing long-term borrowing costs, lower oil prices, and flat-to-lower home prices—all of which we expect in the months ahead—are likely to help produce a soft landing in this sector, rather than a sharp downturn. Should our optimism be well founded, housing should not detract materially from GDP growth, which may still average 3%, or so, from late 2006 through 2007, and a little more than that by the final years of this decade.

Inflation and interest-rate trends are uncertain. Inflation is continuing to show some sharp month-to-month swings as oil prices surge, pull back, then rise again. Backing out the food and energy components—to give us the so-called core rate of inflation—yields a much more stable outcome, with prices remaining in a relatively narrow range. The recent rise in the price of other commodities (e.g., iron ore, copper, and zinc) and a pickup in labor costs pose their own risks to this pricing stability. The stepup in productivity (or labor-cost efficiency) during the first quarter should help lessen the price risks a bit. Interest rates are also charting an uncertain path, as the Federal Reserve's recent decision to raise the Federal Funds rate from 4.75% to 5.00% may not be the last word on monetary tightening. How the interest-rate scenario finally plays out will depend heavily on the likely paths taken by the economy—in terms of growth and inflation.

Global uncertainties are a very serious threat. The risks here have less to do with the developed world, where certain economies in Europe and Asia are performing well, than with the lesser-developed countries, where political and military unrest across the Mideast (notably in Iran and Iraq), and lingering strains

Gross Domestic Product *Chart 1*

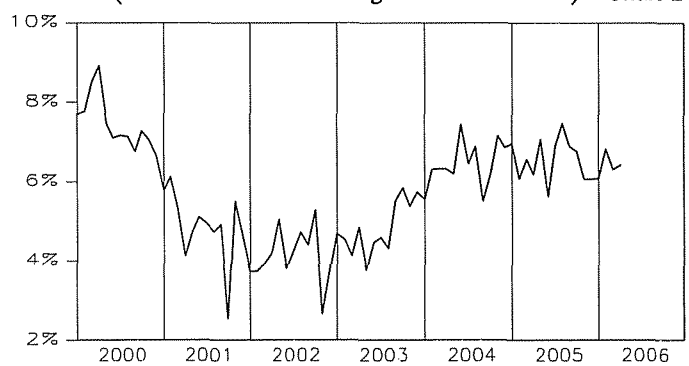
Real Annualized Percent Change - 2000 Chain-Weighted Dollars



Source: U.S. Dept. of Commerce

Personal Consumption Expenditures

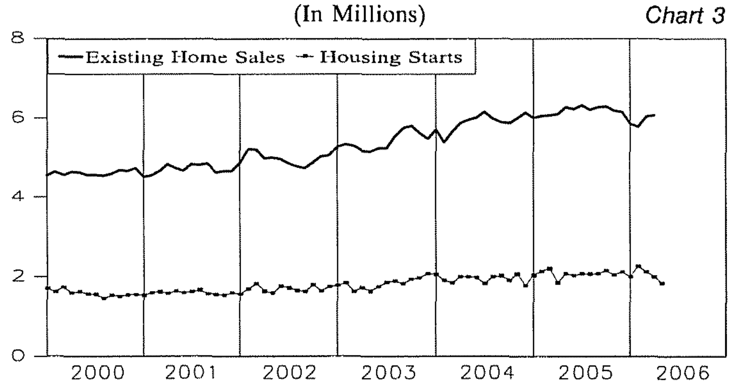
(Annualized Percent Change - Current Dollars) *Chart 2*



Source: U.S. Dept. of Commerce

Existing Home Sales & Housing Starts

(In Millions) *Chart 3*



Sources: U.S. Dept. of Commerce, Nat'l Assoc. of Realtors

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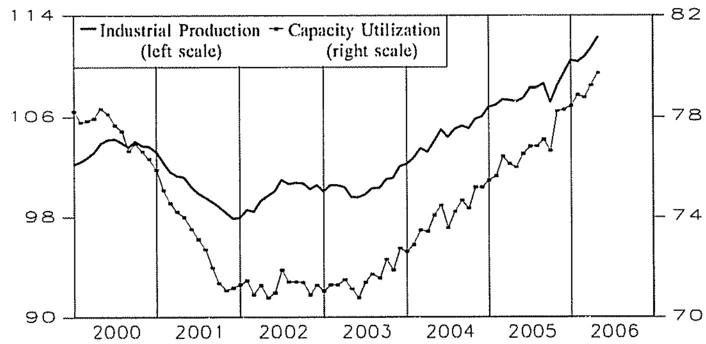
Industrial Production and Capacity Utilization

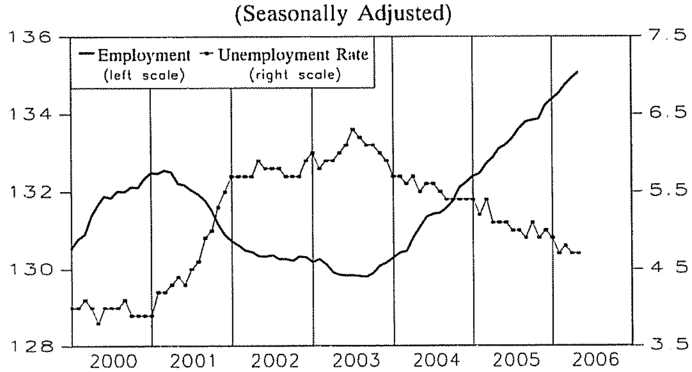
(Index: 1997 = 100) *Chart 4*



Source: Federal Reserve Board

Employment & Unemployment Rate *Chart 5*

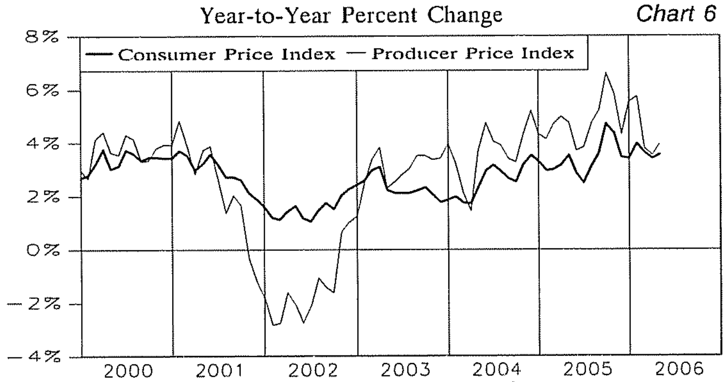
(Seasonally Adjusted)



Source: U.S. Dept. of Labor

Consumer and Producer Price Indexes

Year-to-Year Percent Change *Chart 6*



Source: Bureau of Labor Statistics

with North Korea, Nigeria, and Venezuela hold the potential to further roil the energy markets.

SOME SPECIFICS

Economic Growth: As noted, the pace of economic growth picked up noticeably during the opening three months of this year (Chart 1), with GDP surging by 4.8% on the strength of increases in personal consumption expenditures (Chart 2), government spending (principally on outlays for defense), and nonresidential fixed investment (i.e., capital spending). Restraining growth was a slower rate of increase in residential construction, as housing demand, which had been red hot for years, cooled down a bit, in response to record home prices and rising mortgage rates (Chart 3).

This solid improvement (following a weak close in the fourth quarter of 2005, in which GDP increased by just 1.7%) is likely to continue through the middle part of this year, with growth of 3.3%-3.5% likely during the current quarter. Helping the economy move forward should be further increases in industrial production and factory use (Chart 4), steady growth in payrolls and low unemployment (Chart 5), and moderate gains in retail spending. We also expect the housing market to soften further and the auto sector to remain spotty. Thereafter, we think GDP growth will average 3%, or so, over the following 12 to 18 months, as higher heating and cooling bills and greater borrowing costs induce economically vulnerable consumers to consider reining in their spending. Business investment in plant and equipment should remain strong, as it often does in the mature stages of an economic expansion, and that should help pick up some of the slack.

It should be noted that our GDP forecast for 2006 and 2007 assumes that oil prices will average $60-$65 a barrel, which is somewhat below their recent peak, that the Federal Reserve will be finished raising interest rates by this summer and then start to cut rates next year, and that there

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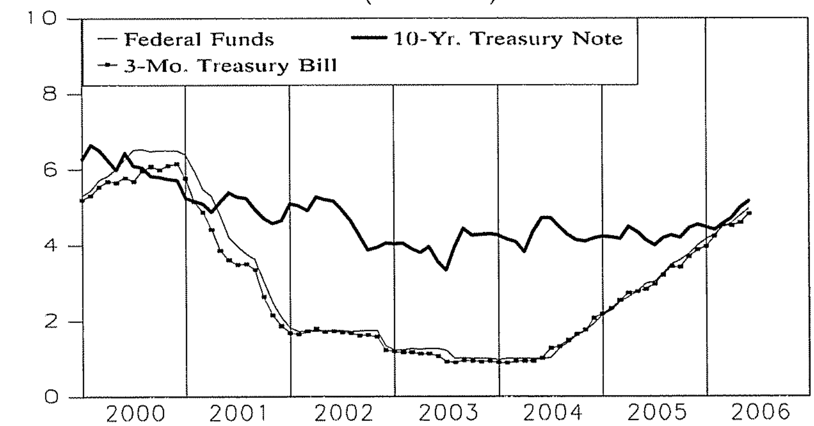
will be no major deterioration on the global front, which is a risky assumption in the post-September 11, 2001 world.

Inflation: Relative pricing stability (excluding food and energy) has been a hallmark of the current business up cycle, as well as over the last two decades. However, there are signs, which suggest that the days of stable inflation may be numbered. We aren't assuming that inflation will suddenly surge. However, we do sense that record oil prices, the relentless rise in industrial materials prices, and the recent rise in wage costs will combine to produce somewhat higher inflation. Helping to limit these likely pricing pressures should be moderating GDP growth, stabilizing energy prices, and additional increases in productivity. Nevertheless, with the outlook for growth brightening in parts of Europe and Asia, it is unlikely we will see a sustained drop in the prices of oil, precious metals, or commodities. However, we may still see a selective easing in producer and consumer prices later this year (Chart 6).

Interest Rates: On May 10th, the Federal Reserve raised the Federal Funds rate from 4.75% to 5.00%, the 16th consecutive increase in that key short-term lending rate. The Fed also indicated that future rate action would be contingent on the strength of the economic data going forward. Given the likely moderation in GDP growth in the second half of this year, we think the Fed will call a halt to its rate tightening initiatives over the summer, with one or two additional rate hikes at most. Such a course should not bring the business expansion to a premature end. As noted, we think the Fed's subsequent moves—which may take place as early as next spring—will focus on reducing rates in recognition of a probable slowing in GDP growth and a likely stabilization of inflation (Chart 7).

Corporate Earnings: The news here continues to be favorable, with key sectors, led by the oil companies and many industrial concerns, routinely reporting solid year-to-year earnings growth. Indeed, the recent quarter was highly rewarding for Corporate America with increases in the range of 13%-15% for the companies listed in the Standard & Poor's 500 Index. Similar strong profit growth is likely during the current period, with healthy demand, rising productivity, and the careful attention to costs probably combining to generate further stellar bottom-line comparisons. Thereafter, earnings growth is likely to moderate somewhat, which would be consistent with the more restrained increases in GDP we see ahead. Earnings should still trend modestly higher in 2007. Steady income growth also is likely over the coming 3 to 5 years.

Selected Interest Rates *Chart 7*
(In Percent)



Source: Federal Reserve Board

THE STOCK MARKET

The recovery in such heretofore moribund industrial sectors as steel, machinery, and aluminum, the record profits in the energy group, and the steady growth in most other sectors had helped—until severe profit-taking set in earlier this month—to give the market a nice lift. In fact, a number of the principal averages—such as the Standard & Poor's 500 Index and the NASDAQ—had, at one point, surged to several-year highs. The Dow Jones Industrial Average, meanwhile, had come to within a whisker of a record close until the aforementioned profit taking set in, while the Value Line (Arithmetic) Index had earlier climbed to an all-time high.

The modest 2006 market gains to date have come against a backdrop of rising oil prices, surging precious metals prices (especially gold, which recently rose above $700 an ounce), and soaring commodities, as well as a difficult and threatening global outlook, which continues to defy easy solutions. The market's resilience, which attests to the importance of earnings, is all the more remarkable given the length of the present bull market, which dates back to 2002.

Going forward, the equity market's fundamentals appear solid, as profits seem set to rise further, interest rates seem likely to peak over the summer, the economy is growing steadily, and oil prices should stabilize later this year, which clearly would be helpful in keeping inflation excesses at bay.

Conclusion: The foregoing would seem to be a prescription for a pickup in the stock market in the months ahead, absent a major shock globally or a serious misstep by an overly aggressive Federal Reserve Board. Please refer to the inside back cover of *Selection & Opinion* for our Asset Allocation Model's current reading.

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Stock Highlight: MCDERMOTT INT'L (MDR - 44.05)

McDermott International is a worldwide energy services company that operates in three market segments. Its marine construction unit, J. Ray McDermott, is involved in the engineering and installation of offshore energy exploration & production facilities. The company's government operations, BWX Technologies, supplies nuclear components and manages facilities for the U.S. Department of Energy. Lastly, Babcock & Wilcox (B&W) produces coal-powered generation systems for various industries.

During the past year, all of McDermott's business units made great strides in lifting sales and net income closer to full recovery. Share net rose 128%, to $1.37 (adjusted for a 3-for-2 stock split payable 6/1/06), in 2005, and we expect this measure to double by 2008. Since the start of 2005, the share price has nearly quadrupled, achieving record highs. Volatile McDermott shares are ranked 1 (Highest) for Timeliness, and offer above-average appreciation potential to 2009-2011. In our view, the equity is best considered by momentum investors.

Business is on an Upswing

J. Ray McDermott is the company's largest unit. This operation is currently benefiting from the restoration and expansion of offshore drilling in the Gulf of Mexico area. Given ample global business opportunity, management has been selective in taking jobs, thus securing good prices. (For example, the Dolphin Energy project in the Middle East will add $20 million in operating profit to current quarter results.) Margins are quite favorable. J. Ray's backlog has mushroomed to $2.4 billion at the end of the recent March quarter, up from $1.1 billion one year ago. Importantly, the unit has bids out for $3.7 billion worth of business, which augurs well for long-term revenue and earnings streams. McDermott's total backlog stands at $5.93 billion, or more than double the year-earlier level.

Elsewhere, this year, McDermott has returned to reporting B&W results on a consolidated basis. Last August, management reached a settlement with asbestos claimants (see below), which enabled B&W to come out of bankruptcy in February. The unit is capitalizing on demand for economical coal-fired power generation. Indeed, it holds about a 50% share of the industrial market, and continues to bring in more business.

Also notable, BWX Technologies is part of a group that has won a contract to operate the Department of Energy's nuclear facility at Los Alamos National Laboratory. Over the next 18 years, this turnkey agreement should provide annual revenues of $80 million and share net of $0.07-$0.08 to McDermott. A solid, long-standing record of service to the U.S. government probably helped to secure participation.

A Richer Cash Position

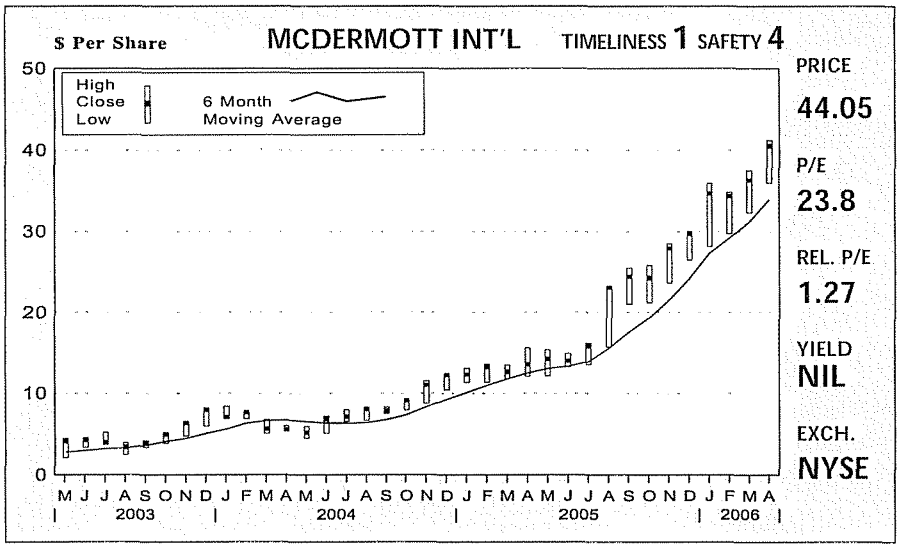
After several years of uneven operating performance, McDermott firmed up results in 2004 and 2005 and cash flow strengthened. This has created greater financial flexibility. This month, the company announced a cash tender offer for $200 million in J. Ray 11% Senior Secured Notes due 2013. Interest savings should be significant. Too, at the close of the latest quarter, cash on the balance sheet hit a high of $687 million (including short-term investments). After completion of the tender offer, we expect most of this cash to be set aside for B&W's asbestos claims. According to the above-mentioned settlement, the unit will contribute $605 million to an asbestos claimant trust, unless the Fairness in Asbestos Injury Resolution (FAIR) Act becomes law by November 30th. (The company would confirm a $250 million B&W note payable and make a $355 million cash payment in May 2007.) If the FAIR passes by that date, which is by no means certain, McDermott would only be on the hook for $25 million. Regardless of the FAIR outcome, McDermott will gain from B&W's positive operating contribution.

Eric M. Gottlieb
Analyst

YEAR	EPS	DIV.	P/E Ratio
2007E	2.40	—	18.4
2006E	1.95	—	22.6
2005A	1.37	—	13.0
2004A	0.60	—	12.6
2003A	d0.85	—	—

STOCK HIGHLIGHT SELECTION

Value Line selects its Stock Highlight from the 100 stocks that have been and currently are ranked 1 (Highest) for probable market performance in the next 12 months. The analysis offered is solely to provide subscribers with a more detailed examination of the individual stock and is not necessarily suggested as a recommendation for a specific portfolio.



(For a full-page report, including company statistics, see page 1393 of Ratings & Reports dated 4/28/06.)

(All per-share numbers are adjusted for a 3-for-2 stock split payable 6/1/06.)

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Stocks for Long-Term Gains

Each week, the *Summary & Index* includes a screen titled "High 3- to 5-year Appreciation Potential" that lists 100 equities under our review with the highest projected capital gains through 2009-2011. Within this list, however, are some very risky issues whose forecasted progress is based on the success of projected turnarounds, which, of course, cannot be assured.

We have greater confidence in our year-ahead ranking system, which is primarily based on historical data, than in our 3- to 5-year projections. Therefore, even if you have long-term investment goals, the best way to fulfill them, in our judgment, is by maintaining a portfolio of timely stocks. Accordingly, this week we've prepared a screen that focuses on long-term gains, but in a rigorous fashion.

First, we limited our roster to stocks whose price appreciation potential through 2009-2011, calculated by using the mid-point of each stock's target price range, is at least 90%, versus the 45% median for the Value Line universe. We also restricted our selections to companies whose per-share earnings have grown at an annualized rate of at least 18% over the last five years and whose Safety rank is 3 (Average) or better. Finally, all stocks had to be ranked at least 2 (Above Average) for Timeliness, thus guarding against near-term underperformance. The equities that survived these cuts are listed in descending order of projected long-term appreciation.

As always, we advise investors to consult the most recent stock analyses in *Ratings & Reports* before investing in any of these issues.

Ratings & Reports Page	Ticker	Company Name	Recent Price	3-5 Year Appreciation Potential	E.P.S. Growth Past 5 Years	Timeliness	Safety	P/E Ratio
883	HD	Home Depot	38.01	175%	20.5%	1	2	12.6
2193	FISV	Fiserv Inc	43.30	130	21.5	2	3	17.5
1075	NSM	National Semic	27.38	120	36.5	2	3	18.9
885	LOW	Lowe's Cos	61.27	100	27.0	2	2	15.3
1870	TWX	Time Warner	17.53	100	49.5	2	3	18.3
1712	BBBY	Bed Bath & Beyond	36.24	95	30.5	2	2	18.2
1686	KSS	Kohl's Corp	57.20	90	20.5	1	3	21.7

CLOSING STOCK MARKET AVERAGES AS OF PRESS TIME

	5/11/2006	5/18/2006	%Change 1 week	%Change 12 months
Dow Jones Industrial Average	11500.73	11128.29	-3.2%	+6.3%
Standard & Poor's 500	1305.92	1261.81	-3.4%	+6.4%
N.Y. Stock Exchange Composite	8526.74	8148.18	-4.4%	+14.6%
NASDAQ Composite	2272.70	2180.32	-4.1%	+7.4%
NASDAQ 100	1657.48	1587.11	-4.2%	+5.2%
American Stock Exchange Index	2012.84	1916.13	-4.8%	+32.1%
Value Line (Geometric)	446.58	426.81	-4.4%	+11.8%
Value Line (Arithmetic)	2104.03	2011.78	-4.4%	+16.7%
London (FT-SE 100)	6042.0	5671.6	-6.1%	+14.6%
Tokyo (Nikkei)	16862.14	16087.18	-4.6%	+48.5%
Russell 2000	757.47	718.47	-5.1%	+18.2%

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Investors' Datebook: June, 2006

DATE	EVENT
6/1	Initial Unemployment Claims-8:30
	Construction Expenditures, April-10:00
	ISM's Purchasing Manager's Index, May-10:00
	Weekly Fed Data-4:30
	Productivity & Costs (Revised)
6/2	Employment Situation, May-8:30
	Factory Orders, April-10:00
6/5	13- & 26-Week Treasury Bill Auction
6/7	Consumer Installment Credit, April-3:00
6/8	Initial Unemployment Claims-8:30
	Weekly Fed Data-4:30
	Wholesale Trade, April
6/9	Merchandise Trade Balance, April-8:30
6/12	13- & 26-Week Treasury Bill Auction
	Treasury Budget Report, May-2:00
6/13	Advance Retail Sales, May-8:30
	Producer Price Index, May-8:30
	Mfg. & Trade: Inventories & Sales, April-10:00
6/14	Consumer Price Index, May-8:30
	Real Earnings, May
6/15	Initial Unemployment Claims-8:30
	Capacity Utilization, May-9:15
	Industrial Production, May-9:15
	Weekly Fed Data-4:30
6/19	13- & 26-Week Treasury Bill Auction
6/20	Housing Starts & Building Permits, May-8:30
6/22	Initial Unemployment Claims-8:30
	Leading Indicators, May-10:00
	Weekly Fed Data-4:30
6/23	Durable Goods Orders, May-8:30
6/26	13- & 26-Week Treasury Bill Auction
	New Home Sales, May-10:00
6/28	FOMC Meeting
6/29	Initial Unemployment Claims-8:30
	Weekly Fed Data-4:30
	Agricultural Prices
	Corporate Profits, 1Q06 (Final)
	FOMC Meeting
	Gross Domestic Product, 1Q06 (Final)
6/30	Personal Income and Outlays, May-8:30

Source: Office of Management & Budget.

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Model Portfolios: Recent Developments

PORTFOLIO I

The first two months of the June quarter have been particularly difficult for Portfolio I, as it has underperformed the major market benchmarks by a considerable margin. Although there have been instances where investors either were disappointed in or grew wary over one or more of our selections' prospects, the general motivation appears to be one of profit taking. We note that the portfolio had a strong first quarter, making it ripe for such action. In the ensuing interim, we have replaced a number of our holdings with stocks that should work to stem the current losses. Meanwhile, in the arena of good news/bad news, Dell has announced that it will start using *Advanced Micro Devices* microprocessors in its server products, giving a large boost to *AMD* shares and support to the semiconductor maker's prospects. On the other hand, a cloud has recently gathered over *RSA Security* stock, as there seems to be some concern over the timing of stock option grants to executive management. We are making no changes this week.

PORTFOLIO II

Portfolio II has been weighed down by the market's recent selloff. Most of the stocks have traded lower lately, erasing the modest gains recorded by the portfolio in the opening weeks of the June quarter. Two of our hardest hit equities in the recent downturn have been *Microchip Technology* and *Textron*, which, not surprisingly, have the two lowest scores, 30 and 60, respectively, for Price Stability among our holdings. (We would attribute most of the recent downturn in *Wachovia* shares to investor skittishness regarding the bank's proposed $25 billion acquisition of a California thrift rather than trends in the broader market.) Still, in keeping with its relatively conservative posture, the portfolio has a median Price Stability of 90, on a scale of 5 to 100. It follows then that our holdings overall would perform relatively well during rocky market stretches. The portfolio's performance thus far in the June quarter, though hardly exciting on an absolute basis, seems to bear this out. We are making no changes to our holdings this week.

PORTFOLIO III

Portfolio III has drifted lower in recent days, as investor fears of rising inflation and further interest rate hikes by the Federal Reserve have taken the air out of the broader market averages. In this climate, even companies that report healthy, but not spectacular, financial results are seeing their stock prices come under pressure. *Home Depot*, for instance, posted better-than-expected share-net growth of 23% during the April interim, thanks to gross margin improvement, good expense management, and a strong sales performance from the former Hughes Supply operations. Yet, its shares retreated when Wall Street raised questions about unexciting market-share trends and the company's decision to no longer report same-store sales figures. That said, we believe that *Home Depot* has a bright future. Growth out to decade's end will likely be fueled by additional margin expansion, and a strategic shift away from retail and toward the highly profitable (and fairly stable) commercial business. We are making no changes to Portfolio III this week.

PORTFOLIO I: STOCKS WITH ABOVE-AVERAGE YEAR-AHEAD PRICE POTENTIAL

(primarily suitable for more aggressive investors)

Ratings & Reports Page	Ticker	Company	Recent Price	Timeliness	Safety	P/E	Yield%	Beta	Financial Strength	Industry Name
1050	AMD	Advanced Micro Dev	30 77	1	4	23 1	Nil	1 95	B+	Semiconductor
374	ABCO	Advisory Board	50 64	2	3	34 2	Nil	0 95	A	Information Services
126	A	Agilent Technologies	34.79	1	3	24 0	Nil	1 55	B++	Precision Instrument
1027	BHE	Benchmark Electronics	25 95	1	3	18 1	Nil	1 55	B+	Electronics
590	BER	Berkley (W R)	34 90	1	3	11 7	0 5	0 85	B+	Insurance (Prop/Cas)
775	ESRX	Express Scripts 'A'	76 02	2	3	24 8	Nil	1.05	A	Pharmacy Services
1426	GS	Goldman Sachs	148.21	2	1	9 2	0 9	1 30	A++	Securities Brokerage
1544	HANS	Hansen Natural Corp	186 83	1	3	52 9	Nil	0 85	B+	Beverage (Soft Drink)
776	HLEX	HealthExtras Inc	28 61	2	3	42 1	Nil	1 05	B+	Pharmacy Services
1113	HPQ	Hewlett-Packard	32 16	1	3	17 9	1 0	1 40	A+	Computers/Peripherals
1067	ISIL	Intersil Corp 'A'	27.43	1	3	28 9	0.7	1 85	B+	Semiconductor
1298	MPS	MPS Group	15 00	1	3	23 1	Nil	1 20	B	Human Resources
223	MDT	Medtronic, Inc	49 19	2	1	20 7	0 9	0 80	A++	Medical Supplies
226	MDCC	Molecular Devices	28 99	2	3	26 4	Nil	0 95	B+	Medical Supplies
2210	PAYX	Paychex, Inc	38 68	1	3	31 2	1 7	1.15	A	Computer Software/Svcs
2212	RSAS	RSA Security	17 39	1	3	32 2	Nil	1 70	B++	Computer Software/Svcs
230	RMD	ResMed Inc	47.33	2	3	35 6	Nil	0 95	B++	Medical Supplies
1954	SLB	Schlumberger Ltd	65 93	1	3	27 1	0.8	1 10	A+	Oilfield Svcs/Equip
908	SCSS	Select Comfort	36 26	1	3	28 1	Nil	0 85	A	Furn/Home Furnishings
354	SRCL	Stericycle Inc	62 50	2	3	27.1	Nil	0 80	B+	Environmental

To qualify for purchase in the above portfolio, a stock must have a Timeliness Rank of 1 and a Financial Strength Rating of at least B+. If a stock's Timeliness rank falls below 2, it will be automatically removed. Stocks in the above portfolio are selected and monitored by Charles Clark, Assistant Research Director.

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PORTFOLIO II: STOCKS FOR INCOME AND POTENTIAL PRICE APPRECIATION

(primarily suitable for more conservative investors)

Ratings & Reports Page	Ticker	Company	Recent Price	Timeliness	Safety	P/E	Yield%	Beta	Financial Strength	Industry Name
593	CB	Chubb Corp	50.59	3	2	11.6	2.0	1.05	A	Insurance (Prop/Cas.)
948	CL	Colgate-Palmolive	60.98	3	1	21.7	2.1	0.60	A++	Household Products
1966	EMN	Eastman Chemical	55.06	3	3	10.7	3.2	1.05	B+	Chemical (Diversified)
788	ETN	Eaton Corp.	76.28	3	1	12.8	1.8	1.10	A+	Auto Parts
1383	FO	Fortune Brands	75.99	NR	1	15.0	1.9	NMF	A+	Diversified Co.
1011	GE	Gen'l Electric	34.42	3	1	17.9	2.9	1.30	A++	Electrical Equipment
1493	HNZ	Heinz (H.J.)	41.03	3	1	20.2	2.9	0.65	A+	Food Processing
1166	HCBK	Hudson City Bancorp	13.52	2	3	24.6	2.3	0.85	B+	Thrift
1389	ITT	ITT Industries	55.05	3	1	19.3	0.8	0.90	A	Diversified Co
218	JNJ	Johnson & Johnson	60.13	3	1	16.6	2.5	0.70	A++	Medical Supplies
447	KMI	Kinder Morgan	85.10	3	3	17.6	4.2	0.95	B+	Natural Gas (Div.)
1072	MCHP	Microchip Technology	33.50	2	3	23.8	2.6	1.30	B+	Semiconductor
943	SON	Sonoco Products	29.75	3	2	14.9	3.2	1.00	A	Packaging & Container
2123	SNV	Synovus Financial	27.00	3	2	14.8	3.0	1.05	B++	Bank
1405	TXT	Textron, Inc.	93.48	3	3	19.3	1.7	1.20	A	Diversified Co.
263	UPS	United Parcel Serv.	79.73	2	1	21.1	1.9	0.75	A+	Air Transport
629	USB	U.S. Bancorp	31.20	3	3	12.2	4.3	1.15	B++	Bank (Midwest)
1665	VFC	V.F. Corp.	61.50	3	2	12.7	3.6	0.95	A	Apparel
2125	WB	Wachovia Corp.	54.01	3	2	11.7	3.8	1.05	A	Bank
2127	WFC	Wells Fargo	66.47	3	1	13.7	3.1	0.85	A+	Bank

To qualify for purchase in the above portfolio, a stock must have a yield that is in the top half of the Value Line universe, a Timeliness Rank of at least 3 (unranked stocks may be selected occasionally), and a Safety Rank of 3 or better. If a stock's Timeliness Rank falls below 3, that stock will be automatically removed. Stocks are selected and monitored by Robert M. Greene, CFA, Senior Industry Analyst.

PORTFOLIO III: STOCKS WITH LONG-TERM PRICE GROWTH POTENTIAL

(primarily suitable for investors with a 3- to 5-year horizon)

Ratings & Reports Page	Ticker	Company	Recent Price	Timeliness	Safety	P/E	Yield%	Beta	3- to 5-yr Appreciation Potential	Industry Name
1202	AFL	Aflac Inc.	47.44	3	2	17.6	1.1	0.90	35 - 90%	Insurance (Life)
1533	BUD	Anheuser-Busch	46.27	4	1	19.0	2.3	0.60	50 - 85	Beverage (Alcoholic)
1580	BFAM	Bright Horizons Family	36.70	3	3	25.7	Nil	0.80	35 - 120	Educational Services
1252	BMY	Bristol-Myers Squibb	24.13	3	2	20.8	4.6	1.00	25 - 65	Drug
1719	CDWC	CDW Corp	55.40	3	3	16.7	0.8	1.20	15 - 80	Retail (Special Lines)
1864	DIS	Disney (Walt)	29.76	1	3	19.8	0.9	1.35	35 - 100	Entertainment
1597	ERTS	Electronic Arts	42.18	5	3	55.5	Nil	1.15	40 - 125	Entertainment Tech
883	HD	Home Depot	38.01	1	2	12.6	1.6	1.10	135 - 215	Retail Building Supply
1495	HRL	Hormel Foods	33.26	3	1	17.1	1.7	0.70	50 - 95	Food Processing
218	JNJ	Johnson & Johnson	60.13	3	1	16.6	2.5	0.70	40 - 75	Medical Supplies
223	MDT	Medtronic, Inc.	49.19	2	1	20.7	0.9	0.80	95 - 135	Medical Supplies
604	PRE	PartnerRe Ltd	61.88	4	3	13.8	2.6	1.10	20 - 85	Insurance (Prop/Cas.)
1547	PEP	PepsiCo, Inc.	59.65	3	1	20.7	2.0	0.65	35 - 70	Beverage (Soft Drink)
1753	PETM	PetSmart, Inc.	27.38	3	3	20.9	0.5	0.95	65 - 135	Retail (Special Lines)
316	SBUX	Starbucks Corp.	36.41	2	3	52.0	Nil	0.80	35 - 90	Restaurant
769	TMX	Telefonos de Mexico ADR	22.06	3	3	9.3	3.6	0.85	35 - 105	Foreign Telecom.
653	UNH	UnitedHealth Group	46.89	3	1	17.1	0.1	0.65	105 - 145	Medical Services
1772	WSM	Williams-Sonoma	40.92	3	3	22.2	1.0	1.20	35 - 95	Retail (Special Lines)
1513	WWY	Wrigley (Wm.) Jr.	47.20	5	1	24.8	2.2	0.60	60 - 90	Food Processing
1087	XLNX	Xilinx Inc.	27.04	2	3	24.8	1.3	1.75	65 - 140	Semiconductor

To qualify for purchase in the above portfolio, a stock must have worthwhile and longer-term appreciation potential. Among the factors considered for selection are a stock's Timeliness and Safety Rank and its 3- to 5-year appreciation potential. (Occasionally a stock will be unranked (NR), usually because of a short trading history or a major corporate reorganization.) Stocks in the above portfolio are selected and monitored by Justin Hellman, Senior Industry Analyst.

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Equity Funds Average Performance

TOTAL RETURN*
Percent Change through April, 2006

	One Month	Three Month	Year-to-Date	One Year	Five Year (Annualized)
Performance Objective					
Aggressive Growth	0.68	2.29	7.80	24.60	2.92
Growth	0.91	2.16	6.10	19.80	3.47
Growth/Income	1.67	3.18	6.40	17.40	3.82
Income	1.98	3.45	6.60	20.50	5.81
Balanced	0.94	1.70	3.90	11.40	3.92
International					
European Equity	5.55	11.31	19.20	37.90	10.27
Foreign Equity	5.23	7.95	16.30	41.50	11.94
Global Equity	3.08	5.38	11.20	28.70	6.73
Pacific Equity	4.26	7.27	14.70	43.50	11.89
Sector					
Energy/Natural Resources	6.72	2.25	18.20	60.50	18.72
Financial Services	2.94	5.57	8.50	23.10	8.40
Health	-3.56	-3.09	-0.40	12.80	3.06
Precious Metals	12.34	13.12	35.20	106.10	35.88
Real Estate	-3.04	3.45	10.20	25.70	19.85
Technology	0.34	1.56	8.20	30.50	-3.18
Utilities	1.65	2.08	6.20	17.80	1.43
Other					
Convertible	0.87	1.89	5.80	16.80	4.73
Flexible	1.18	1.91	4.80	12.60	4.17
Specialty	2.00	4.30	8.80	22.30	4.42
Small Company	0.54	4.38	12.50	31.00	9.29
S&P 500	**1.34**	**2.88**	**5.60**	**15.40**	**2.69**

Source: The Value Line Mutual Fund Survey

* *Dividends plus capital appreciation. Dividends are reinvested as of the ex-dividend date. The returns are arithmetic averages based on the performances of all funds within each category.*

Fixed-Income Funds Average Performance

TOTAL REINVESTMENT*
Percent Change through April, 2006

	One Month	Three Month	Year-to-Date	One Year	Five Year (Annualized)
U.S. Government and Agency Bond					
Short term—U.S. Gov't	0.17	0.15	0.30	0.80	2.37
Immediate term—U.S. Gov't	-0.16	-0.70	-0.80	-0.10	3.67
Long term—U.S. Gov't	-0.39	-1.24	-1.40	-0.50	3.87
GNMA	-0.04	-0.19	Nil	1.40	3.72
Corporate Bond					
High Quality	-0.07	-0.52	-0.50	0.70	4.12
High Yield	0.56	1.69	2.90	7.60	5.96
International	1.27	0.70	1.90	3.00	8.20
Municipal Bond					
California Tax Exempt	-0.23	-0.27	-0.10	1.40	4.27
New York State Tax Exempt	-0.19	-0.21	-0.10	1.20	4.00
Other States Tax Exempt	-0.03	-0.04	0.20	2.10	4.19

Source: The Value Line Mutual Fund Survey

* *The cumulative rate of investment growth, including the reinvestment of dividend income and capital gains distributions as of the ex-dividend date. The investment objective averages are arithmetic averages calculated on the basis of the total reinvested rates of return produced by all funds within each investment objective category.*

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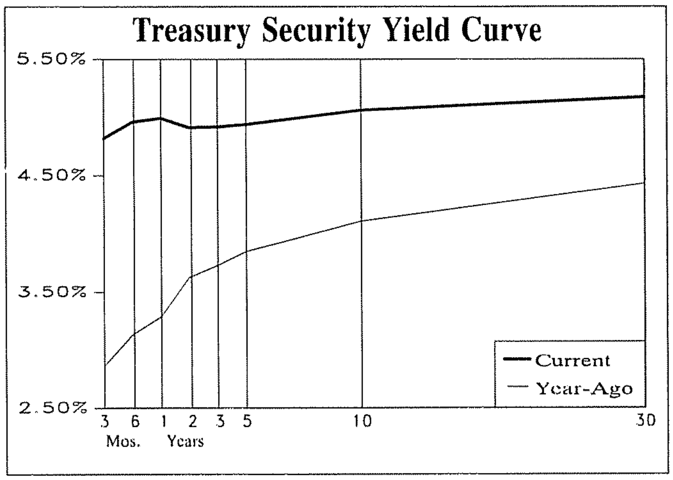
Selected Yields

	Recent (5/18/06)	3 Months Ago (2/16/06)	Year Ago (5/19/05)
TAXABLE			
Market Rates			
Discount Rate	6.00	5.50	4.00
Federal Funds	5.00	4.50	3.00
Prime Rate	8.00	7.50	6.00
30-day CP (A1/P1)	5.00	4.49	3.02
3-month LIBOR	5.19	4.77	3.28
Bank CDs			
6-month	3.06	2.89	2.26
1-year	3.87	3.46	2.77
5-year	4.03	3.97	3.80
U.S. Treasury Securities			
3-month	4.82	4.53	2.86
6-month	4.96	4.68	3.13
1-year	4.99	4.70	3.29
5-year	4.94	4.58	3.85
10-year	5.06	4.58	4.11
10-year (inflation-protected)	2.37	2.08	1.64
30-year	5.17	4.57	4.43
30-year Zero	5.06	4.62	4.45
Mortgage-Backed Securities			
GNMA 6.5%	6.01	5.33	4.96
FHLMC 6.5% (Gold)	6.19	5.88	5.09
FNMA 6.5%	6.15	5.74	4.86
FNMA ARM	4.81	4.47	3.48
Corporate Bonds			
Financial (10-year) A	6.01	5.50	4.89
Industrial (25/30-year) A	6.28	5.68	5.36
Utility (25/30-year) A	6.28	5.63	5.25
Utility (25/30-year) Baa/BBB	6.59	5.98	5.61
Foreign Bonds (10-Year)			
Canada	4.32	4.19	4.09
Germany	4.03	3.51	3.35
Japan	1.95	1.57	1.27
United Kingdom	4.58	4.17	4.37
Preferred Stocks			
Utility A	7.25	7.07	6.96
Financial A	6.37	6.22	5.94
Financial Adjustable A	5.52	5.52	5.52
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.58	4.42	4.25
25-Bond Index (Revs)	5.24	5.14	4.81
General Obligation Bonds (GOs)			
1-year Aaa	3.62	3.26	2.72
1-year A	3.75	3.38	2.89
5-year Aaa	3.67	3.50	2.98
5-year A	3.95	3.78	3.28
10-year Aaa	4.10	3.86	3.49
10-year A	4.42	4.17	3.84
25/30-year Aaa	4.53	4.36	4.30
25/30-year A	4.79	4.61	4.54
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.65	4.37	4.31
Electric AA	4.66	4.44	4.44
Housing AA	4.70	4.63	4.65
Hospital AA	4.90	4.79	4.48
Toll Road Aaa	4.77	4.63	4.44



Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 5/10/06	Recent Levels 4/26/06	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	2145	1466	679	1678	1694	1730
Borrowed Reserves	156	103	53	160	147	221
Net Free/Borrowed Reserves	1989	1363	626	1518	1547	1509

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels 5/8/06	Recent Levels 5/1/06	Change	Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1382.8	1388.3	-5.5	-0.1%	3.5%	1.2%
M2 (M1+savings+small time deposits)	6770.9	6794.8	-23.9	2.2%	4.2%	4.4%

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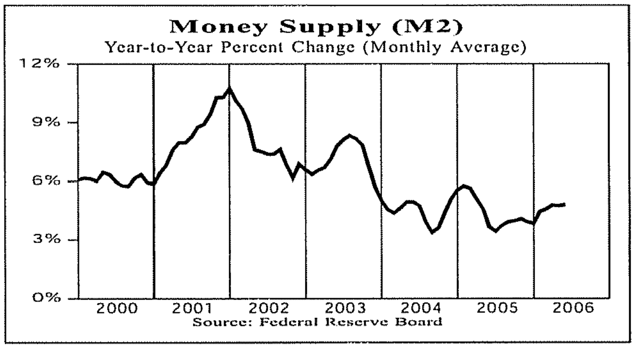
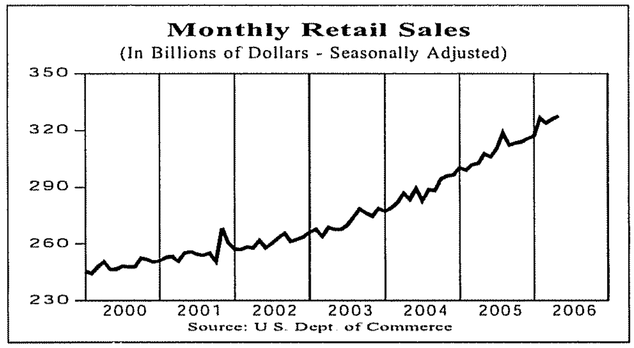
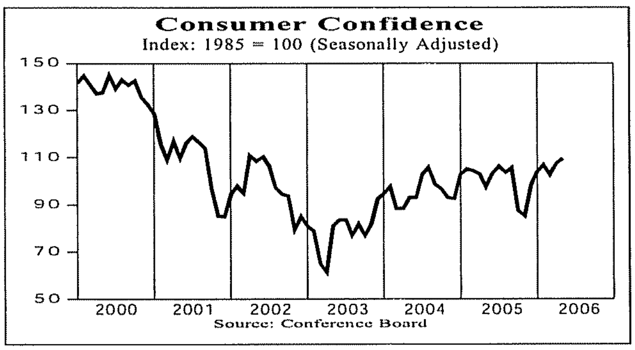
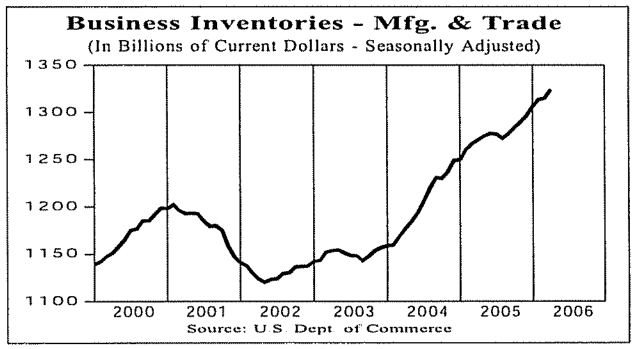
Tracking the Economy









Major Insider Transactions†

PURCHASES

Latest Full-Page Report	Timeliness Rank	Company	Insider, Title	Date	Shares Traded	Shares Held(a)	Price Range	Recent Price
2138	3	Aon Corp.	E.R Martin, Dir	5/8/06	5,000	10,000	$37 81-$37 82	35 57
410	3	Chesapeake Energy	A K McClendon, Chair	5/5/06-5/9/06	400,000	19,463,552	$32 54-$33 19	29 96
1488	-	Dean Foods	A J Bernon, Pres	5/5/06	3,500	597,944	$36.70	35 64
1947	2	Helix Energy Solutions	O E Kratz, Chair	5/3/06	15,000	4,995,147	$40 08	39.11
1967	3	Hexcel Corp	M L. Solomon, Dir	5/8/06-5/9/06	25,000	93,354	$23 11-$23 20	21.55
1587	3	Laureate Education	R Appadoo, Pres	5/8/06	30,000	59,664	$48 74	46 27
1372	3	Watts Water Techn	R.E Jackson Jr., Dir	5/9/06	5,000	13,669	$38 50	36 35

SALES

Latest Full-Page Report	Timeliness Rank	Company	Insider, Title	Date	Shares Traded	Shares Held(a)	Price Range	Recent Price
2231	-	Google, Inc	K Shriram, Dir	5/2/06	150,000	12,681	$390 00-$402 00	374 50
2231	-	Google, Inc	S Brin, Pres.	5/2/06-5/3/06	264,499	NA	$390 00-$401 00	374 50
215	2	Intuitive Surgical	R W Duggan, Dir	5/10/06	55,000	716,736	$129 05	115 43
874	3	NVR, Inc	D.C Schar, Chair	5/10/06	16,833	413,059	$739 88-$749 00	667 00
419	2	Occidental Petroleum	S.I Chazen, CFO	5/9/06	114,000	932,768	$104 52	92 86
419	2	Occidental Petroleum	J.W Morgan, VP	5/9/06	100,000	328,995	$105 43	92 86
1509	5	Tyson Foods 'A'	D.J Tyson, Dir	5/2/06	750,000	NA	$14 64	15 17

* *Beneficial owner of more than 10% of common stock*
(a) *Beneficial ownership at end of month in which transaction occurred*
† *Includes only large transactions in U S -traded stocks, excludes shares held in the form of limited partnerships, excludes options & family trusts*

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Market Monitor

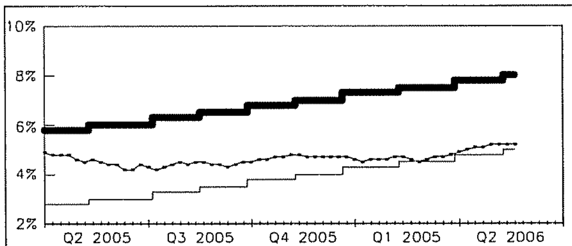
Valuations and Yields	5/18	5/11	13-week range	50-week range	Last market top (3-7-2005)	Last market bottom (10-9-2002)
Median price-earnings ratio of VL stocks	18.7	19.6	18.5 - 19.6	17.5 - 19.6	18.9	14.1
P/E (using 12-mo. est'd EPS) of DJ Industrials	16.2	16.6	16.1 - 16.6	15.3 - 16.8	16.5	15.2
Median dividend yield of VL stocks	1.6%	1.6%	1.5 - 1.6%	1.5 - 1.7%	1.6%	2.4%
Div'd yld. (12-mo. est.) of DJ Industrials	2.4%	2.3%	2.3 - 2.4%	2.2 - 2.5%	2.2%	2.6%
Prime Rate	8.0%	8.0%	7.5 - 8.0%	6.0 - 8.0%	5.5%	4.8%
Fed Funds (Target)	5.0%	5.0%	4.5 - 5.0%	3.0 - 5.0%	2.5%	1.8%
91-day T-bill rate	4.8%	4.8%	4.6 - 4.8%	3.0 - 4.8%	2.7%	1.6%
Moody's Aaa Corporate bond yield	5.9%	6.0%	5.3 - 6.0%	4.9 - 6.0%	5.4%	6.1%
30-year Treasury bond yield	5.2%	5.2%	4.5 - 5.2%	4.2 - 5.2%	4.7%	4.7%
Bond yield minus average earnings yield	0.6%	0.9%	-0.1 - 0.9%	-0.6 - 0.9%	0.1%	-1.0%

Market Sentiment	Wk. Ending 5/18	Wk. Ending 5/11	10-week average	13-week range	Last market top (3-7-2005)	Last market bottom (10-9-2002)
% of total NYSE short sales by:						
Public	57	59	58	56 - 59	46	53
NYSE specialists	13	12	13	10 - 15	26	37
Other NYSE members	30	29	30	28 - 31	28	10
Total NYSE short sales/total NYSE volume	13.7%	13.6%	13.7%	13.0 - 14.1%	12.9%	12.9%
Short interest/avg. daily volume (5 weeks)	4.9	5.1	5.2	4.8 - 5.4	5.1	5.3
Odd-lot sales/purchases	1.1	1.0	1.1	0.9 - 1.2	1.3	1.1
CBOE put volume/call volume	1.28	.89	.87	.58 - 1.28	.80	.96

VALUE LINE ASSET ALLOCATION MODEL

(Based only on economic and financial factors)

	Current (effective 2/11/05)	Previous
Common Stocks	75%-85%	70%-80%
Cash and Treasury Issues	25%-15%	30%-20%



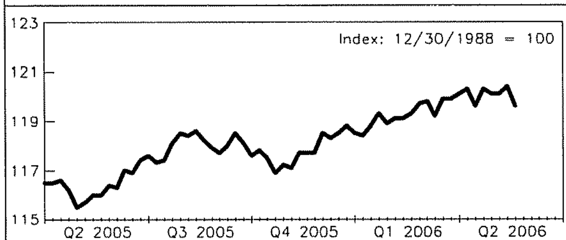
INTEREST RATES

Prime Rate

Federal Funds

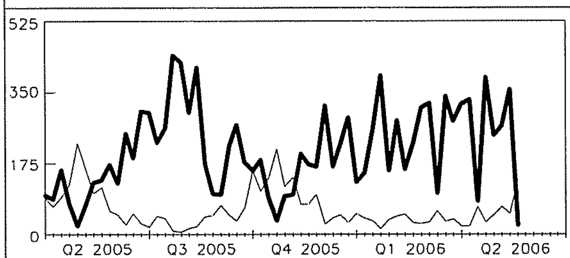
30-Year Treasury Bond

	Recent	Previous Week
Prime Rate	8.0%	8.0%
Fed Funds (Target)	5.0%	5.0%
30-Yr Treasury	5.2%	5.2%



VALUE LINE UNIVERSE

	Recent	Previous Week
Advances	136	1073
Declines	1500	553
Issues Traded	1639	1640
Market Value ($ Trillion)	17.704	18.619



VALUE LINE COMPOSITE

New Highs

New Low

	Recent	Previous Week
New Highs	23	356
New Lows	137	52

INDUSTRY PRICE PERFORMANCE LAST SIX WEEKS ENDING 5/17/2006

7 Best Performing Industries

Cable TV	+8.7%
Trucking	+6.6%
Beverage (Soft Drink)	+5.5%
Maritime	+4.6%
Auto Parts	+2.9%
Tobacco	+2.4%
Chemical (Basic)	+2.2%

7 Worst Performing Industries

Homebuilding	-22.1%
Cement & Aggregates	-16.0%
Biotechnology	-15.2%
Water Utility	-13.9%
Wireless Networking	-13.4%
Telecom. Equipment	-13.2%
Retail Building Supply	-11.3%

The corresponding change in the Value Line Arithmetic Average is -4.1%

CHANGES IN FINANCIAL STRENGTH RATINGS

Company	Prior Rating	New Rating	Ratings & Reports Page
Franklin Resources	B++	A	2150

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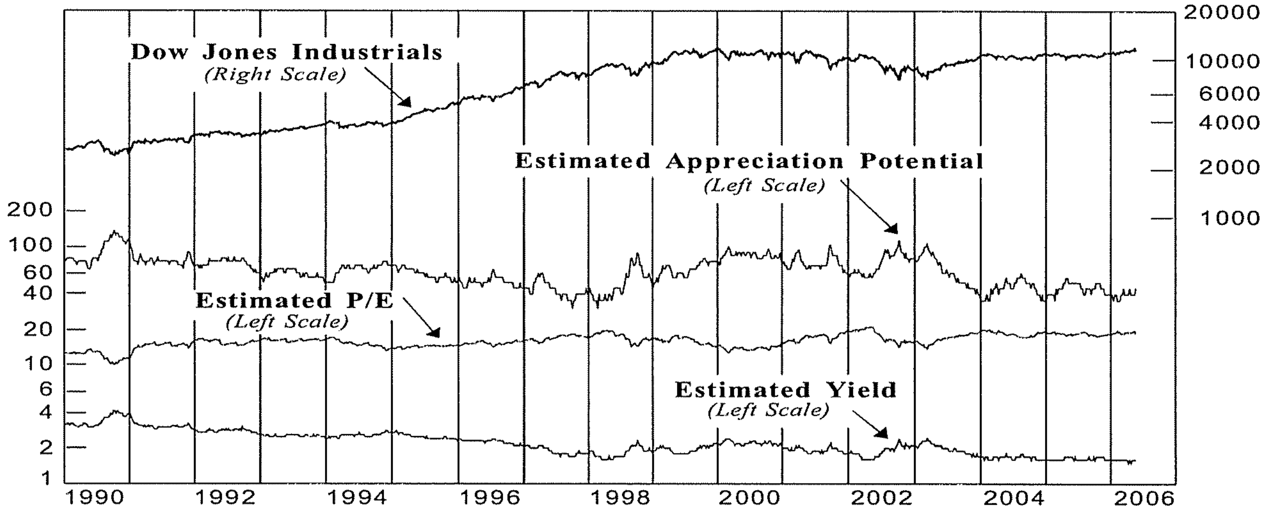
Stock Market Averages

VALUE LINE ESTIMATED P/E, YIELD, APPRECIATION POTENTIAL
VERSUS DOW JONES INDUSTRIALS *(JANUARY 2, 1990 - MAY 17, 2006)*

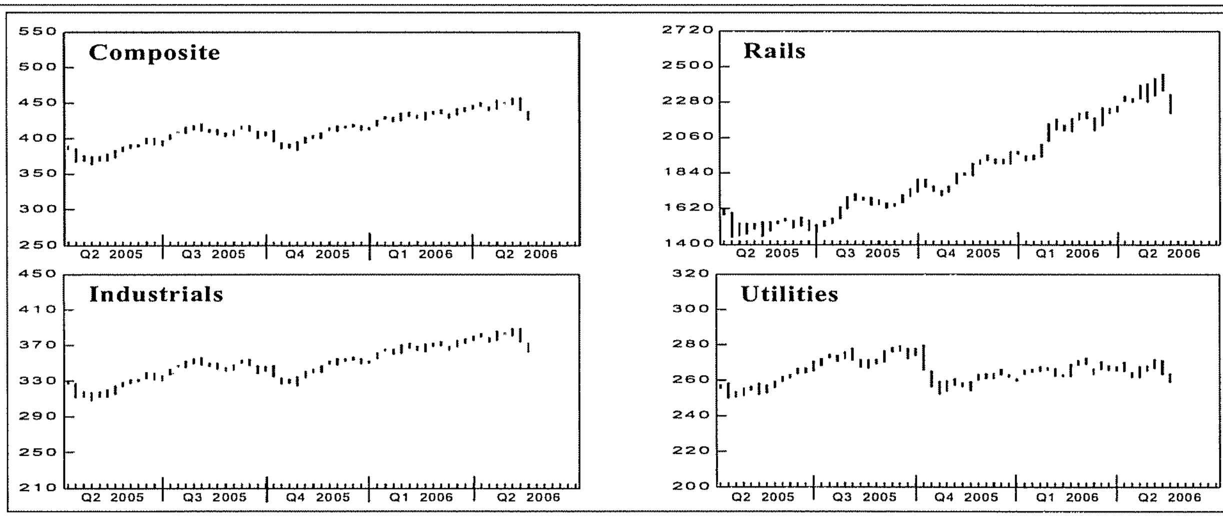


THE VALUE LINE GEOMETRIC AVERAGES	Composite 1610 stocks	Industrials 1495 stocks	Rails 7 stocks	Utilities 108 stocks
5/12/2006	439.93	373.74	2352.86	263.21
5/15/2006	437.96	371.92	2326.94	263.72
5/16/2006	436.81	370.91	2327.47	263.32
5/17/2006	429.70	364.90	2263.89	259.27
5/18/2006	426.81	362.30	2210.94	259.07
%Change last 4 weeks	-5.9%	-6.1%	-6.6%	-3.0%

	Arithmetic Composite 1610 stocks
5/12/2006	2073.05
5/15/2006	2062.94
5/16/2006	2058.26
5/17/2006	2025.10
5/18/2006	2011.78
%Change last 4 weeks	-5.6%

THE DOW JONES AVERAGES	Composite 65 stocks	Industrials 30 stocks	Transportation 20 stocks	Utilities 15 stocks
5/12/2006	3917.73	11380.99	4840.54	400.07
5/15/2006	3929.60	11428.77	4846.35	401.51
5/16/2006	3911.71	11419.89	4798.44	400.01
5/17/2006	3827.82	11205.61	4670.97	392.62
5/18/2006	3804.31	11128.29	4627.33	393.25
%Change last 4 weeks	-1.6%	-1.9%	-1.7%	-0.7%

WEEKLY VALUE LINE GEOMETRIC AVERAGES *(APRIL 1, 2005 - MAY 18, 2006)*



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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS	)	
AND ELECTRIC COMPANY FOR APPROVAL	)	
OF ITS 2006 COMPLIANCE PLAN FOR	)	**CASE NO. 2006-00208**
RECOVERY BY ENVIRONMENTAL	)	
SURCHARGE	)	

DIRECT TESTIMONY OF
SHARON L. DODSON
DIRECTOR, ENVIRONMENTAL AFFAIRS
E.ON U.S. SERVICES INC.

Filed: June 23, 2006

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

A. My name is Sharon L. Dodson. I am the Director of Environmental Affairs for E.ON U.S. Services Inc., 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 my testimony as Appendix A.

Q. Have you previously testified before the Commission?

A. Yes. I have testified in Case Nos. 2004-00426[1] and 2004-00421[2], the Companies' most recent Environmental Cost Recovery applications.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring exhibits, identified as exhibits SLD-1 through SLD-6. These exhibits are:

Exhibit SLD-1	Trimble County Station Title V Operating Permit: V-02-043 rev. 2
Exhibit SLD-2	Mill Creek Station Title V Operating Permit: 145-97-TV
Exhibit SLD-3	Company's Letter to KYDAQ on SO_3 Mitigation
Exhibit SLD-4	KYDAQ SO_3 Mitigation Response Letter
Exhibit SLD-5	Mill Creek Station Agreed Board Order signed December 14, 2004

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

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

Exhibit SLD-6 Approval Letter from Louisville Metro Air Pollution Control District for installation of particulate matter continuous emission monitors at Mill Creek Station

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to identify the environmental requirements which cause the need for the pollution control facilities in LG&E's 2006 Environmental Compliance Plan ("2006 Plan") and demonstrate how those facilities will allow LG&E to comply with these environmental regulations. A copy of the 2006 Plan is presented in Exhibit JPM-1 to the testimony of Mr. Malloy. The projects identified in the 2006 Plan are necessary for LG&E's compliance with the requirements of the Clean Air Act as amended ("CAAA"), the Clean Air Interstate Rule ("CAIR"), the Clean Air Mercury Rule ("CAMR"), the Clean Air Visibility Rule ("CAVR", also known as the Regional Haze 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. Since the passage of the initial Clear Air Act in 1970, environmental compliance has been an ongoing, everyday activity at our facilities and for our operations. All subsequent amendments to and revisions of environmental laws and regulations have increased LG&E's environmental compliance obligations over time. Continued environmental compliance becomes increasingly challenging over time due to the ever increasing standards. Thus, there is a need for continuous investment in and maintenance of environmental pollution control equipment and facilities. The protection of air quality especially has given rise to the stringent environmental regulations that, in turn, have caused the need for the pollution control projects in LG&E's 2006 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 United States Environmental Protection Agency ("EPA") has granted the State of Kentucky primacy for implementing the provisions of the CAAA through the State Implementation Plan ("SIP") process. In Chapter 77 of the Kentucky Revised Statutes, the General Assembly for the Commonwealth of Kentucky has granted the Louisville Metro Air Pollution Control District ("LMAPCD") primacy for implementing the Jefferson County portion of the State Implementation Plan. The State of Kentucky is currently revising its SIP process to incorporate CAIR and CAMR emission restrictions into its program.

LG&E has seven coal-fired units located in Jefferson County, Kentucky and one coal-fired unit located in Trimble County, Kentucky. The Jefferson County units fall under the jurisdiction of the LMAPCD and must comply with air emission regulations promulgated by that local agency. The Trimble County unit is under the jurisdiction of the Kentucky Environmental and Public Protection Cabinet, Division for Air Quality ("KYDAQ") and must comply with air emission regulations promulgated by that state agency. A second coal-fired unit is currently under construction at the Trimble County Power Station and is expected to be completed by 2010.

Project No. 18 - Installation of Pollution Control Equipment on Trimble County Unit 2

Q. What pollution control equipment is being built with the Trimble County Unit No. 2?

A. As discussed in the testimony of Mr. Malloy, the following Air Quality Control System ("AQCS") pollution control equipment will be built in connection with the construction of the Trimble County Unit No. 2 facility:

- Selective Catalytic Reduction ("SCR") system,
- Dry Electrostatic Precipitator ("DESP"),
- Pulverized Activated Carbon ("PAC") injection system,
- Hydrated lime injection system,
- Pulse Jet Fabric Filter ("PJFF"),
- Limestone forced oxidation Wet Flue Gas Desulfurization ("WFGD") equipment, and
- Wet Electrostatic Precipitator ("WESP").

Q. What current environmental regulations require the construction of AQCS on Trimble County Unit 2?

A. The AQCS in this project are being undertaken in order to comply with several environmental regulations. Under Kentucky Regulation 401 KAR 51:017, 401 KAR 52:020 and Federal Regulation 40 CFR Part 52.21, the construction of a new unit (i.e., Trimble County Unit 2) is required to undergo a Prevention of Significant Deterioration ("PSD") review, which includes Best Available Control Technology ("BACT") and air quality impact demonstrations. From the PSD review of Trimble County Unit 2, these pollution control technologies were determined to meet the requirements of BACT for particulate matter ("PM/PM_{10}"), sulfuric acid ("H_2SO_4") mist, and fluorides (as "HF"). Through the PSD review process, no significant net increase in sulfur dioxide ("SO_2") or nitrogen oxides ("NO_x") emissions has occurred at the facility as a result of taking federally enforceable emission limits on Trimble County Unit 1 for those pollutants. Based on this review, a Title V Operating Permit (Exhibit SLD-1) was obtained with controls specified to be installed on Trimble County Unit 2 as operating limitations. The overall need for a DESP, PAC and hydrated lime system is being addressed as either an administrative amendment or off-permit change.

The acid rain control requirements under Title IV of the CAAA also play a role in determining the need for these devices. Under that program, each utility unit in the 48 contiguous states must have sufficient SO_2 allowances at the end of each year to account for its emissions. Trimble County Unit 2 will not be given any SO_2 allowances because it is a new unit. LG&E has built a "bank" of SO_2 allowances that could be used to cover these new SO_2 emissions; however, that bank will be depleted within the next few years. The WFGD will reduce SO_2 emissions and reduce the burden on the Companies' SO_2 allowance bank.

On March 10, 2005, the EPA promulgated the CAIR under its authority provided under Section 110 of the CAAA. The CAIR is a multi-pollutant strategy rule requiring significant additional reduction of SO_2 and NO_x emissions in order to further reduce levels of ozone and fine particulate matter ("$PM_{2.5}$") in the atmosphere. 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, similar to SO_2 under the Acid Rain Program and NO_x under the NO_x SIP Call. For SO_2, current Acid Rain Program allocations would be used. The program will reduce emissions over two phases. The CAIR targets annual SO_2 reductions of 3.6 million tons during Phase I (from 2010-2014) and an additional 2 million tons during Phase II (from 2015 and beyond). Because LG&E (and all other utilities impacted by the CAIR) has already received Acid Rain Program allowances for its existing units for 2010 through 2034, the EPA provides that utilities surrender those allowances at a greater rate than is currently required: on a 2-for-1 and 2.87-for-1 basis, during Phase I and Phase II respectively. However, pre-2010 Acid Rain Program SO_2 allowances (i.e., banked allowances) would retain their full value. As stated earlier, Trimble County Unit 2 will not be given any allowances when it starts operation in 2010. Therefore, the installation of this WFGD and associated equipment is necessary to ensure LG&E's continued compliance with all current regulations requiring the reduction of SO_2 emissions.

Additionally, for NO_x, the CAIR will replace the NO_x SIP Call ozone-season NO_x reduction requirements with new annual and ozone-season reduction requirements based on the cap-and-trade allowance method. For Kentucky on an annual basis, the CAIR allocations represent a 42% reduction from 2003 NO_x levels for the first phase (2009-2014) of the program and a 58% reduction from 2003 NO_x emissions during the second phase (2015 and beyond). During the ozone season (May-September), emissions will be capped at a level to the NO_x SIP Call requirements for 2009-2014 and an approximate 15% reduction is prescribed for 2015 and beyond. The annual and ozone season programs are two separate and distinct allowance programs. CAIR Ozone Season allowances can not be used for compliance with the CAIR Annual Program and CAIR Annual allowances can not be used for compliance with the CAIR Ozone Season Program. To aid the Companies in meeting the requirements of the NO_x portion of the CAIR, an SCR and associated equipment is needed on Trimble County Unit 2.

With the installation of an SCR, sulfur trioxide ("SO_3") levels within the flue gas stream will increase due to the SCR catalyst's reaction with SO_2. Additionally, various conditions could cause condensation of SO_3 in the PJFF resulting in sulfuric acid ("H_2SO_4") deposition. To address the corrosion and operational issues that could occur from the formation of sulfuric acid and comply with applicable regulatory obligations, a hydrated lime injection system upstream of the PJFF must be installed. Sulfuric acid mist could potentially impact human health and the environment and subsequently result in non-compliance with the general duty provisions of KRS Chapter 224. While the WESP is BACT for removal of sulfuric acid mist and ensures compliance with permitted particulate matter emission limitations, the hydrated lime injection equipment will assist in overall removal of the acid mist while protecting the operating equipment.

On March 15, 2005, the CAMR was promulgated requiring the reduction of mercury emissions from all coal-fired generating facilities. The CAMR is based on "cap-and-trade" methodologies. It is to be implemented in two phases. In Phase I (2010-2017), mercury emissions are to be capped at 38 tons nationwide. In Phase II (2018 and beyond), mercury emissions are to be reduced to 15 tons nationwide (a 69% reduction). Allowances must be surrendered to cover equal amounts of emissions. New sources such as Trimble County Unit 2 are also stipulated to have an emission limit. Trimble County Unit 2 has a limit of $13x10^{-6}$ lb/MWh as stipulated in its operating permit (Exhibit SLD-1). To meet that limit, the PAC injection system coupled with the PJFF is needed to reduce mercury emissions.

In April 1999, the final CAVR was issued. The final rule gives states flexibility in determining reasonable progress goals for the areas of concern, taking into account the statutory requirements of the CAAA. The final regulation requires all 50 states to cut emissions of fine particulate matter and other air pollutants, including SO_2 and NO_x. Under the rule, the target year is 2064 for restoring clear visibility to 156 areas classified as Class I under the CAAA, although incremental improvements in air quality are required to begin early in the next decade. A DESP, PJFF and WESP are being installed to reduce particulate matter emissions from this unit. The WESP will also be integral in reducing the fine particulate and sulfuric acid mist emissions from this unit.

Q. Has the Company received the necessary environmental permits for the operation of Trimble County Unit No. 2?

A. Yes. The Companies have already received an operating permit (Exhibit SLD-1) for this unit that stipulates the operating and emission limitations and regulatory requirements placed on this unit. The pollution control equipment systems contained in Project 18 are necessary for LG&E to comply with the pollution control requirements placed on this unit by this operating permit.

Project No. 19 – Sorbent Injection Technology Installations – Mill Creek Units 3 and 4, Trimble County Unit 1

Q. Are there environmental regulations which cause the need for the installation of sorbent injection technology on Mill Creek Units 3 and 4 and Trimble County Unit 1?

A. Yes. Current state environmental laws and regulations requires the installation of Sorbent Injection Technology at these facilities. The Companies contacted KYDAQ to confirm the agency's interpretation of the relevant laws and regulations as shown in Exhibit SLD-3. It is the position of the KYDAQ that the "General Duty" provisions of the Kentucky Revised Statutes ("KRS") Chapter 224 require necessary and appropriate action on a case by case basis to mitigate SO_3 emissions that could potentially impact human health and the environment. If a permittee fails to address SO_3 emissions that may potentially impact human health or the environment, the LMAPCD and KYDAQ reserve the right to take appropriate action under KRS Chapter 224 to compel compliance with this requirement. As shown in Exhibit SLD-4, KYDAQ believes it is "necessary and appropriate that such emission be controlled."

Q. What environmental permits will be required for the installation of the proposed equipment?

A. The LMAPCD will require a construction permit prior to installation and use of the equipment. The construction permits will be incorporated into the facility's Title V Operating Permit at a later time. The KYDAQ will also require permitting which may either be incorporated directly into the Title V Operating Permit or through separate construction permitting.

Project No. 20 – Continuous Mercury Monitor Installations – All LG&E Coal-Fired Units

Q. What are the environmental regulations causing the need for the installation of continuous mercury monitors on all units in the LG&E generation fleet?

A. As mentioned in the discussion for Project 18, the CAMR was promulgated in March 2005. Within that rule, monitoring of mercury emissions is required beginning January 1, 2009. Therefore, mercury monitoring equipment must be purchased, installed and certified before that date. 40 CFR Part 75 continuous emission monitoring installation and certification procedures will be followed to place these monitors in operation.

Q. What environmental permits will be required for the installation of the proposed equipment?

A. No new permits are required for the installation of this equipment. 40 CFR Part 75 continuous emission monitoring installation and certification procedures will be followed to place these monitors in operation. Existing Title V Operating Permits will be revised to reflect the installation and operation of these monitors.

Project No. 21 – Particulate Matter Continuous Emissions Monitors– Mill Creek Units 1-4

Q. What are the environmental regulations causing the need for the installation of particulate matter continuous emissions monitors on Mill Creek Units 1-4?

A. Compliance with federal (40CFR Part 60) and local (Louisville Metro Air Pollution Control District Regulations 6.02, 6.07, 7.01 and 7.06) particulate matter emissions standards is the paramount need for this project. These regulations require the application of emission monitoring equipment to ensure that compliance is met. Specifically, opacity monitoring equipment is stated in the regulation as the method for indicating compliance with the particulate matter standard. However, the saturated flue gas conditions that occur within Mill Creek Station's stacks do not allow accurate opacity measurement at the emission exit point using ordinary opacity monitors.

To deal with this issue, the Title V Operating Permit for Mill Creek Station (Exhibit SLD-2) was written to allow the investigation of an extractive opacity monitor to determine whether this new monitoring technology would allow for the measurement of opacity in a wet flue gas environment. Testing of the device was performed. However, the results were inconclusive within the timeframe of deadlines stipulated within the Title V Operating Permit.

Because of this result and to meet installation deadlines outlined in the Title V Operating Permit, four ordinary opacity monitors along with associated equipment and structures were installed at the exit of the electrostatic precipitator of Mill Creek Unit 1. However, monitoring in this location has not accurately depicted what emissions are actually being emitted into the environment (i.e., at the stack).

In continuing to strive for an accurate emission monitoring device, LG&E entered into an Agreed Board Order on December 14, 2004 with the Louisville Metro Air Pollution Control District ("LMAPCD") (Exhibit SLD-5) to investigate particulate matter continuous emission monitoring equipment. This Agreed Order suspended any further installation deadlines as specified within the Title V Operating Permit. The ensuing investigation showed the installed device to be an excellent monitor of particulate matter emissions in a wet flue gas. On November 1, 2005, LMAPCD (Exhibit SLD-6) approved the installation of the device on all four units at

Mill Creek Station as an alternate monitoring methodology to continuous opacity measurement.

Q. What environmental permits will be required for the installation of the proposed equipment?

A. No new permits were required for the installation of this equipment. Exhibit SLD-4 stipulated a timeframe for the installations of monitoring devices. The PM CEMS were approved and have been installed. Per Exhibit SLD-6, the Title V Operating Permit (Exhibit SLD-2) will be amended to indicate that PM CEMS are to be used to demonstrate compliance with applicable PM standards.

Q. Does LG&E's 2006 Environmental Compliance Plan list the environmental permits and regulations that are applicable to LG&E?

A. Yes. My testimony describes the environmental regulations, permit requirements and compliance orders applicable to LG&E. These regulations and requirements are summarized in Column 5 in Exhibit JPM-1. The pollution control facilities listed as Projects 18-21 of LG&E's 2006 Environmental Compliance Plan enable the Company to continue to fulfill its environmental compliance obligations. The evidence of LG&E's satisfaction of its environmental compliance obligation and thus the need for the four projects in the 2006 Environmental Compliance Plan is shown in Column 6, "Environmental Permits" in Exhibit JPM-1.

Q. Does this conclude your testimony?

A. Yes it does.

VERIFICATION

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

The undersigned, **Sharon L. Dodson**, being duly sworn, deposes and says she is Director of Environmental Affairs for E.ON U.S. Services Inc., and that she 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 her information, knowledge and belief.

Sharon L. Dodson

SHARON L. DODSON

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of June 2006.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

TAMMY J. ELZY
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
My Commission Expires Nov. 9, 2006

Appendix A

Sharon L. Dodson

Director – Environmental Affairs
E.ON U.S. Services Inc.
220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40202
(502) 627-2940

Education

- The School of Conservation, Georgia, The Professional Forestry and Wildlife Conservation Program, Diploma – 1998
- Saint Francis College, Pennsylvania, Business Administration (24 credits) – 1986
- Grove City College, Pennsylvania, B.S. in Chemical Engineering – 1984

Previous Positions

Edison International, Rosemead, California

1999-2003 –	Manager, Environmental, Health and Safety Midwest Generation, LLC, Homer City Generating Station Homer City, Pennsylvania

GPU Generation Inc., Morristown, New Jersey

1995-1999 –	Environmental Engineer Sr. 1, Environmental Affairs Johnstown, Pennsylvania
1994-1995 –	Team Leader, Conemaugh Generating Station Water Team New Florence, Pennsylvania
1993-1994 –	Station Engineer Sr.1, Chemical, Conemaugh Generating Station New Florence, Pennsylvania
1989-1993 –	Station Engineer III, Conemaugh Generating Station New Florence, Pennsylvania
1986-1989 –	Station Engineer II, Conemaugh Generating Station New Florence, Pennsylvania
1984-1986 –	Production Engineer I Johnstown, Pennsylvania

Exhibit SLD-1 – Trimble County Station Title V Operating Permit: V-02-043 rev. 2

Commonwealth of Kentucky
Environmental and Public Protection Cabinet
Department for Environmental Protection
Division for Air Quality
803 Schenkel Lane
Frankfort, Kentucky 40601
(502) 573-3382

Final

AIR QUALITY PERMIT
Issued under 401 KAR 52:020

Permittee Name:	**Louisville Gas and Electric Company**
Mailing Address:	**P.O. Box 32010, Louisville, Kentucky, 40232**
Source Name:	**Louisville Gas and Electric Company**
Mailing Address:	**P.O. Box 32010, Louisville, Kentucky, 40232**
Source Location:	**487 Corn Creek Road, Bedford, Kentucky,**
Permit Number:	**V-02-043 Revision 2**
Source A. I. #:	**4054**
Activity #:	**APE20040003**
Review Type:	**Operating, PSD/TV**
Source ID #:	**21-223-00002**
ORIS Code:	**6071**
Regional Office:	**Florence Regional Office 8020 Veterans Memorila Drive, Suite 110 Florence, KY 41042 (859) 525-4923**
County:	**Trimble**
Application Complete Date:	**February 11, 2005**
Issuance Date:	**June 20, 2003**
Revision Date:	**November 17, 2005 January 4, 2006**
Expiration Date:	**June 20, 2008**

E-Signed by Diana Andrews
VERIFY authenticity with ApproveIt

Diana J. Andrews

John S. Lyons, Director
Division for Air Quality

Revised 10/19/05

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Rev#	Permit type	Log #	Complete Date	Issuance Date	Summary of Action
----	Initial Issuance	F720	12-13-1996	NA	Was not issued proposed or final. Public notification was done.
1	Acid Rain Permit	F526	3-03-1998	3-05-1999	Permit for Unit 1-tangential coal fired boiler
2	PSD permit	53460	01-14-2001	06-22-2001	Permit issued for CT unit only without expiration
3	PSD/TV proposed permit	53460	12-19-02	06-06-03	Consolidating all permits into one
4	Permit Revision one	APE2004 0003	12-24-04	01-04-05	Emission limit as enforceable as practical matter (emission reduction) and the usage of two to three dry bulk trailers for fly ash transport
5	Significant Revision	APE2004 0004	2-11-05	1-4-06	Construction of new utility boiler, creditable emission reduction on source wide sulfur dioxide, and addition of NOx budget to the permit.

SECTION A - PERMIT AUTHORIZATION

Pursuant to a duly submitted application the Kentucky Division for Air Quality hereby authorizes the operation of the equipment described herein in accordance with the terms and conditions of this permit. This permit has been issued under the provisions of Kentucky Revised Statutes Chapter 224 and regulations promulgated pursuant thereto.

The permittee shall not construct, reconstruct, or modify any affected facilities without first having submitted a complete application and receiving a permit for the planned activity from the permitting authority, except as provided in this permit or in 401 KAR 52:020, Title V Permits.

Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by this Cabinet or any other federal, state, or local agency.

SECTION B -EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

Emissions Unit: 01 (01) - Unit 1 Indirect Heat Exchanger

Description:
Construction commenced: on or before September 18, 1978
Pulverized coal-fired, dry bottom, tangentially fired, equipped with Selective Catalytic Reduction (SCR), electrostatic precipitator and wet spray scrubber with limestone/lime injection
Up to forty (40) percent petroleum coke co-firing with coal
Number two fuel oil used for startups and flame stabilization
Maximum continuous rating: 5,333 mmBtu/hour

Applicable Regulations:
401 KAR 51:017, Prevention of significant deterioration of air quality
401 KAR 51:160, NO_x requirements for large utility and industrial boilers; incorporating by reference 40 CFR 96
401 KAR 52:060, Acid rain permits, incorporating by reference the Federal Acid Rain provisions as codified in 40 CFR Parts 72 to 78
401 KAR 59:015, New Indirect Heat exchangers with more than 250 mmBtu per hour capacity and commenced on or after August 17, 1971;
40 CFR 60 Subpart D, Standards of Performance for fossil-fuel-fired steam generators, for an emissions unit greater than 250 mmBtu/hour and commenced after August 17, 1971;

1. **Operating Limitations:**
   None

2. **Emission Limitations:**
   a) Pursuant to 401 KAR 59:015, Section 4(1)(b), and 401 KAR 51:017, particulate emissions shall not exceed 0.1 lb/mmBtu based on a three-hour average.

      The permittee may assure continuing compliance with the particulate emission standard by operating the affected facility and associated control equipment such that the opacity does not exceed the upper limit of the indicator range developed from continuous opacity monitoring (COM) data collected during stack tests. If five (5) percent of COM data (based on a three-hour rolling average) recorded in a calendar quarter show excursions from the indicator range, the permittee shall contact the Division within thirty (30) days after the end of the quarter to schedule a stack test to demonstrate compliance with the particulate standard while operating at the conditions which resulted in the excursions. The Division may waive this testing requirement upon a demonstration that the cause of the excursions has been corrected, or may require stack tests at any time pursuant to 401 KAR 50:045, Performance tests.

   b) Pursuant to 401 KAR 59:015, Section 4(2), emissions shall not exceed twenty (20) percent opacity based on a six-minute average except a maximum of twenty-seven (27) percent opacity for not more than one (1) six (6) minute period in any sixty (60)

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. **Emission Limitations continued:**

consecutive minutes. Opacity shall be demonstrated by using EPA reference Method 9. Alternatively, the permittee may use COM in determining compliance with opacity.

c) Pursuant to 401 KAR 51:017, sulfur dioxide emissions shall not exceed 0.84 lb/mmBtu based on a three-hour rolling average.

d) Pursuant to 401 KAR 59:015, Section 6(1)(c), nitrogen oxides emissions expressed as nitrogen dioxide shall not exceed 0.7 lb/mmBtu based on a three-hour rolling average.

e) Pursuant to 401 KAR 51:001, Section 1, (146), source has accepted a voluntary limit such that consecutive twelve month rolling total of nitrogen oxide emissions shall not exceed 5,556 tons per year, which through this permit is enforceable as a practical matter. This limit commenced on January 1, 2005.

f) Pursuant to 40 CFR Part 76, nitrogen oxides emissions expressed as nitrogen dioxide shall not exceed 0.45 lb/mmBtu on an annual basis. See Section J, Acid Rain Permit.

g) Pursuant to 401 KAR 51:001, Section 1, (146), source has accepted a voluntary limit such that consecutive twelve month rolling total of sulfur dioxide emissions shall not exceed 4,822 tons per year, which through this permit is enforceable as a practical matter. This limit shall commence on January 1, 2006.

Compliance with nitrogen oxide and sulfur dioxide emissions:

Permittee shall monitor and calculate emissions on a consecutive twelve month rolling total as measured by the continuous emissions monitor (CEM) required pursuant to 40 CFR 75.2(a)

3. **Testing Requirements:**

a) The permittee shall submit a schedule within six months from the initial issuance date of this permit to conduct at least one performance test for particulate within one year following the issuance of this permit. The upper limit of the indicator range shall be developed from the COM data collected during the stack tests.

b) If no additional stack tests are performed pursuant to Condition 2. a) above, the permittee shall conduct one performance test for particulate emissions within the third year of the term of this permit to demonstrate compliance with the allowable standard.

c) The permittee shall determine the opacity of emissions from the stack by EPA Reference Method 9 annually, or more frequently if requested by the Division.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. **Specific Monitoring Requirements:**

a) Pursuant to 401 KAR 59:015, Section 7(1) and Section 7(4), 401 KAR 59:005, Section 4, continuous emission monitoring systems shall be installed, calibrated, maintained, and operated for measuring the opacity of emissions, sulfur dioxide, nitrogen oxides, and either oxygen or carbon dioxide emissions. The owner or operator shall ensure the continuous emission monitoring systems are in compliance with, and the owner or operator shall comply with the requirements of 401 KAR 59:005, Section 4.

b) Pursuant to 401 KAR 59:015, Section 7(3), for performance evaluations of the sulfur dioxide and nitrogen oxides continuous emission monitoring system as required under 401 KAR 59:005, Section 4(3) and calibration checks as required under 401 KAR 59:005, Section 4(4), reference methods 6 or 7 shall be used as applicable as described by 401 KAR 50:015.

c) Pursuant to 401 KAR 59:015, Section 7(3), sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to 40 CFR 60, filed by reference in 401 KAR 50:015.

d) Pursuant to 401 KAR 59:015, Section 7(3), the span value for the continuous emission monitoring system measuring opacity of emissions shall be eighty (80), ninety (90), or one-hundred (100) percent and the span value for the continuous emission monitoring system measuring sulfur dioxide and nitrogen oxides emissions shall be in accordance with 401 KAR 59:015, Appendix C.

e) All span values computed under (d) above for burning combinations of fuels shall be rounded to the nearest 500 ppm.

f) Continuous emission monitoring data shall be converted into the units of applicable standards using the conversion procedure described in 401 KAR 59:015, Section 7(5).

g) Pursuant to 401 KAR 59:015, Section 7(3), for an indirect heat exchanger that simultaneously burns fossil fuel and non-fossil fuel, the span value of all continuous monitoring systems shall be subject to the Division's approval.

5. **Specific Record Keeping Requirements:**

a) Pursuant to 401 KAR 59:005, Section 3 (4), the owner or operator of the indirect heat exchanger shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems and devices; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Pursuant to 401 KAR 52:020, records, including those documenting the results of each compliance test, shall be maintained for five (5) years.

c) Pursuant to 401 KAR 59:005, Section 3(2), the owner or operator of this unit shall maintain the records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the emissions unit, any malfunction of the air pollution control equipment; or any period during which a continuous monitoring system or monitoring device is inoperative.

d) The permittee shall maintain records of the COM data on a three-hour rolling average basis, the number of excursions above the indicator range, time and date of excursions, opacity value of the excursions, and percentage of the COM data showing excursions from the indicator range in each calendar quarter.

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 59:005, Section 3 (3), minimum data requirements which follow shall be maintained and furnished in the format specified by the Division. Owners or operators of facilities required to install continuous monitoring systems shall submit for every calendar quarter a written report of excess emissions (as defined in applicable sections) to the Division. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information:

1) The magnitude of the excess emission computed in accordance with the 401 KAR 59:005, Section 4(8), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

2) All hourly averages shall be reported for sulfur dioxide and nitrogen oxides monitors. The hourly averages shall be made available in the format specified by the Division.

3) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the emissions unit. The nature and cause of any malfunction (if known), the corrective action taken or preventive measures adopted.

4) The date and time identifying each period during which continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

5) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

b) Pursuant to 401 KAR 59:015, Section 7(7), for the purposes of reports required under 401 KAR 59:005, Section 3(3), periods of excess emissions are defined as follows:

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

6. Specific Reporting Requirements continued:

1) Excess emissions are defined as any six minute period during which the average opacity of emissions exceeds twenty percent opacity, except that one (1) six (6) minute average per hour of up to twenty-seven (27) percent opacity need not be reported.

2) Excess emissions of sulfur dioxide are defined as any three (3) hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable sulfur dioxide emissions standards.

3) Excess emissions for emissions units using a continuous monitoring system for measuring nitrogen oxides are defined as any three (3) hour period during which the average emissions (arithmetic average of three contiguous one hour periods) exceed the applicable nitrogen oxides emissions standards.

c) The permittee shall report the number of excursions above the indicator range, date and time of excursions, opacity value of the excursions, and percentage of the COM data showing excursions from the indicator range in each calendar quarter.

d) The permittee shall report quarterly the twelve-month rolling total sulfur dioxide and nitrogen oxides emissions.

7. **Specific Control Equipment Operating Conditions:**

a) The electrostatic precipitator and wet spray scrubber with limestone/lime injection shall be operated as necessary to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

SECTION B -EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Units: 02 (02, 03, 04) - Auxiliary boilers A, B, and C

Description:
Constructed commenced on or before: December 28, 1987
#2 Fuel Oil-fired Units
Maximum continuous rating: 11.76 mmBtu/hour, each

Applicable Regulations:
401 KAR 59:015, New indirect heat exchangers, applicable to an emissions unit less than 250 mmBtu/hour and commenced on or after April 9, 1972.

1. Operating Limitations:
Total annual #2 fuel oil usage rate for all auxiliary boilers A, B, and C (emission point 02) shall not exceed 682,500 gallons per year and sulfur content shall not exceed 0.8 percent, to demonstrate non-applicability of Prevention of Significant Deterioration of Air Quality.

2. Emission Limitations:

a) Pursuant to 401 KAR 59:015, Section 4(1)(b), particulate emissions shall not exceed 0.1 lb/mmBtu based on a three-hour average. Compliance with the allowable particulate standard may be demonstrated by calculating particulate emissions using fuel heating value, and emission factor information (Particulate formula: (0.002 lbs/gallon) / heating value in mmBtu/gallon.)

b) Pursuant to 401 KAR 59:015, Section 4(2), emissions shall not exceed twenty (20) percent opacity based on a six-minute average except a maximum of forty (40) percent opacity for not more than six (6) consecutive minutes in any sixty (60) consecutive minutes during cleaning the firebox or blowing soot is allowed.

c) Pursuant to 401 KAR 59:015, Section 5(1)(b), the sulfur dioxide emission rate shall not exceed 0.8 lb/mmBtu based on a three-hour average. Compliance with the allowable sulfur dioxide standard shall be demonstrated by calculating sulfur dioxide emissions using fuel heating value, fuel supplier certification with sulfur content, and emission factor information (AP-42 factors below). Sulfur dioxide formula: (0.142 lb/gallon x Percent Sulfur in fuel) / heating value in mmBtu/gallon.

3. Testing Requirements:
Compliance with the opacity standard shall be demonstrated by reading the opacity once in every quarter by EPA Reference Method 9.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. **Specific Monitoring Requirements:**

   a) To demonstrate continuing compliance with the fuel oil sulfur content limitation, monitoring of operations shall consist of, on an as-received basis, fuel supplier certification of the sulfur content of the fuel oil to be combusted. The fuel supplier certification shall include the name of the oil supplier, sulfur content, and a statement that the oil complies with the specifications under the definition for distillate oil in 401 KAR 60:005.

   b) The fuel oil sulfur content and heating value shall be determined for the #2 fuel oil, as received, by fuel supplier certification.

5. **Specific Record Keeping Requirements:**

   a) Pursuant to 401 KAR 59:005, Section 3 (4), the owner or operator of the indirect heat exchanger shall maintain a file of all measurements, including monthly #2 fuel oil usage. The owner or operator shall maintain a file of the fuel supplier certification; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection. The file shall be retained for at least five (5) years following the date of such measurements, maintenance, reports, and records.

   b) Records of the #2 fuel oil used shall be maintained.

6. **Specific Reporting Requirements:**

   See Section F.

7. **Specific Control Equipment Operating Conditions:**

   NA

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 05 (05, 06, -) - Fossil Fuel Handling Operations and Plant Roadways

Description:
Construction commenced on or before: 1990

Equipment includes:	Maximum Operating Rate (Tons/hour)
Continuous barge unloader, one barge unloader bin, and fossil fuel stacker reclaimer	5500
One active pile, one inactive pile, stackout conveyor S, one reclaim hopper	3000
Plant Roadways	NA

Applicable Regulations:
401 KAR 63:010, Fugitive emissions, and
401 KAR 51:017, Prevention of significant deterioration of air quality.

1. Operating Limitations:

a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following:

1. application and maintenance of asphalt, application of water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dusts;

2. operation of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling;

3. the maintenance of paved roadways in a clean condition;

4. the prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or other earth moving equipment or erosion by water.

b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

e) No one shall allow earth or other material being transported by truck or earth moving equipment to be deposited onto a paved street or roadway, pursuant to 401 KAR 63:010, Section 4.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. Emission Limitations:
None

3. Testing Requirements:
None

4. Specific Monitoring Requirements:

See Section F.

5. Specific Record Keeping Requirements:

a) Records of the fossil fuels received and processed shall be maintained for emissions inventory purposes.

b) Annual records estimating the tonnage hauled for plant roadways shall be maintained for emissions inventory purposes.

6. Specific Reporting Requirements:
See Section F.

7. **Specific Control Equipment Operating Conditions:**

a) The surfactants, enclosures, and a rotoclone for the fossil fuel receiving operations and the dust water suppressant system for the stockpile operations shall be used as necessary to maintain compliance with applicable requirements, in accordance with manufacturer's specifications and/or standard operating practices.

b) Plant roadways shall be controlled with water as necessary to comply with 401 KAR 63:010.

c) Records regarding the maintenance and use of the surfactants, enclosures, and a rotoclone for the fossil fuel receiving operations and the dust water suppressant system for the stockpile operations shall be maintained.

d) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 07 (07, 08, 09) - Fossil Fuel Handling Operations (Please refer to Units 36, 37, 38, and 39 for additional future fossil fuel handling operation information)

Description:
Construction commenced on or before: 1990

Continuous Barge Unloader –
One Barge Unloader Bin

Conveyor System -

Conveyor Belt A:	From Continuous Barge Unloader to Conveyor B
Conveyor Belt B:	From Conveyor A to Transfer House/Conveyor C
Conveyor Belt C:	From Transfer House to Coal Sample House Bin
Conveyor Belt D:	From Coal Sample House Bin to Conveyor E1 or S
Conveyor Belt E1:	From Conveyor D to Active Storage and Crusher House
Conveyor Belts F1 & F2:	From Crusher House to Conveyors G1 & G2
Conveyor Belts G1 & G2:	From Conveyors F1 & F2 to Unit 1 & 2 Coal Silos
Conveyor Belt S:	From Conveyor D to One Inactive Fossil Fuel Pile
Reclaim Hopper & Conveyor Belt R1:	From One Inactive Fossil Fuel Pile to Crusher House

Crusher House -
Two crushers, fossil fuel crusher bin, and fuel blender: Crusher House Activities

Operating Rate–

Continuous Barge Unloader	Transfer Rates
One Barge Unloader	5,500 tons/hour

Conveyor System -

Conveyor Belt A:	5,500 tons/hour
Conveyor Belt B:	5,500 tons/hour
Conveyor Belt C:	5,500 tons/hour
Conveyor Belt D:	3,000 tons/hour
Conveyor Belt E1:	2,640 tons/hour
Conveyor Belts F1 & F2:	1,320 tons/hour
Conveyors G1 & G2	1,320 tons/hour
Conveyor Belt S:	1,650 tons/hour
Reclaim Hopper & Conveyor Belt R1:	1,320 tons/hour

Crusher House -
Two crushers, fossil fuel crusher bin, and fuel blender: 3,600 tons/hour

Power House -
Six Unit 1 fossil fuel silos: 800 tons/hour

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Applicable Regulations:
401 KAR 60:005, incorporating by reference 40 CFR 60 Subpart Y, Standards of Performance for Coal Preparation Plants for units commenced after October 24, 1974
401 KAR 51:017, Prevention of significant deterioration of air quality

1. **Operating Limitations:**
   None

2. **Emission Limitations:**
   Pursuant to 401 KAR 60:005 incorporating by reference 40 CFR 60.252, the owner or operator subject to the provisions of this regulation shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

3. **Testing Requirements:**
   Pursuant to 401 KAR 60:005 incorporating by reference, 40 CFR 60.254, EPA Reference Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity at least annually, or more frequently if requested by the Division.

4. **Specific Monitoring Requirements:**
   The permittee shall perform a qualitative visual observation of the opacity of emissions from each stack on a weekly basis and maintain a log of the observations. If visible emissions from any stack are seen, the permittee shall determine the opacity of emissions by Reference Method 9 and instigate an inspection of the control equipment making any necessary repairs.

5. **Specific Record Keeping Requirements:**
   Records of the fossil fuels processed shall be maintained for emissions inventory purposes.

6. **Specific Reporting Requirements:**
   See Section F.

7. **Specific Control Equipment Operating Conditions:**
   a) The enclosures, surfactants, and rotoclone(s) for crushing and associated conveying operations, the partial enclosures for conveyor system with belts A, B, C, D, G1, G2, 1, 2, and fuel blender, and baghouse for the six fossil fuel silos shall be used/operated as necessary to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices.

   b) Records regarding the maintenance and use/operation of the control equipment listed in 7(a) shall be maintained.

   c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 10 (10 and 11) - Lime/Limestone Handling and Processing

Description:

Equipment includes: Receiving Operations: clamshell unloader, clamshell barge unloader bin;
Stockpile/Stackout Operations: active pile, inactive pile
Construction commenced on or before: 1990
Maximum Operating Rate (Receiving): 1650 Tons/hour
Maximum Operating Rate (Stockpile/Stackout): 1500 Tons/hr

Applicable Regulations:
401 KAR 63:010, Fugitive emissions
401 KAR 51:017, Prevention of significant deterioration of air quality

1. **Operating Limitations:**
   a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following:

      1. application and maintenance of asphalt, application of water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dusts;

      2. operation of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling.

   b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

2. **Emission Limitations:**
   None

3. **Testing Requirements:**
   None

4. **Specific Monitoring Requirements:**
   See Section F.

5. **Specific Record Keeping Requirements:**
   Records of the lime and/or limestone received and processed shall be maintained for emissions inventory purposes.

6. **Specific Reporting Requirements:**
   See Section F.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

7. **Specific Control Equipment Operating Conditions:**

   a) The wet spray low water surfactant and enclosures shall be used as necessary to maintain compliance with applicable requirements, in accordance with manufacturer's specifications and/or standard operating practices.

   b) Records regarding the maintenance and use of the wet spray low water surfactant and enclosures shall be maintained.

   c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Units: 12 (12, 13) - Lime/Limestone Handling and Processing

Description:
Equipment Includes: underground crushing operation (one crusher);
and milling operations (two ball mills)
Construction commenced on or before: 1990
Operating Rate: 260 Tons/hour, each

Applicable Regulations:
401 KAR 60.670, New nonmetallic mineral processing plants, incorporating by reference 40 CFR 60, Subpart OOO, applies to each of the emissions units listed above, commenced after August 31, 1983
401 KAR 51:017, Prevention of significant deterioration of air quality

1. **Operating Limitations:**
   None

2. **Emission Standards:**
   a) Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.672(e), no owner or operator shall cause to be discharged into the atmosphere from any building enclosing any transfer point on a conveyor belt or any other emissions unit any visible fugitive emissions.

   Note that the crusher building is located underground with no direct vent to the atmosphere; therefore as long as this is the case it is assumed to be in compliance.

3. **Testing Requirements:**
   In determining compliance with 401 KAR 60.670, incorporating by reference 40 CFR 60.672(e) for fugitive emissions from buildings, the owner(s) or operator(s) shall determine fugitive emissions while all emissions units are operating in accordance with EPA Reference Method 22, annually.

4. **Specific Monitoring Requirements:**
   The permittee shall inspect the control equipment weekly and make repairs as necessary to assure compliance.

5. **Specific Record Keeping Requirements:**
   Records of the lime and/or limestone processed shall be maintained for emissions inventory purposes.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

6. **Specific Reporting Requirements:**
   a) Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.676, the owner(s) or operator(s) of any emissions unit shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards of 40 CFR 60.672 and 401 KAR 59:310, including reports of observations using Method 22 to demonstrate compliance.

   b) See Section F.

7. **Specific Control Equipment Operating Conditions:**
   a) The enclosure shall be used as necessary to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices.

   b) Records regarding the maintenance of the enclosure shall be maintained.

   c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 14 (14) - Lime/Limestone Handling and Processing

Description:
Equipment Includes: conveyors and transfer points (conveyor system, belts A, B, C, transfer bin, and reclaim hopper)
Construction commenced on or before: 1990
Maximum Operating Rate: 1500 Tons/hour, each

Applicable Regulations:
401 KAR 60:670, incorporating by reference 40 CFR 60 Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants, as modified by Section 3 of 401 KAR 60:670, applies to each of the emissions units listed above, commenced after August 31, 1983
401 KAR 51:017, Prevention of significant deterioration of air quality

1. **Operating Limitations:**
   None

2. **Emission Standards:**
   a) Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.672 (b), the owner(s) or operator(s) shall not cause to be discharged into the atmosphere from any transfer point on belt conveyors or from any other emissions unit any fugitive emissions which exhibit greater than ten (10) percent opacity.

   b) Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.672(e), no owner or operator shall cause to be discharged into the atmosphere from any building/enclosure enclosing any transfer point on a conveyor belt or any other emissions unit any visible fugitive emissions.

3. **Testing Requirements:**
   a) EPA Reference Method 9 and the procedures in 40 CFR 60.11 and 40 CFR 60.675 shall be used for determining opacity, annually.

   b) In determining compliance with 401 KAR 401 KAR 60.670, incorporating by reference 40 CFR 60.672(e) for fugitive emissions from buildings/enclosures, the owner(s) or operator(s) shall determine fugitive emissions while all emissions units are operating in accordance with EPA Reference Method 22, annually.

4. **Specific Monitoring Requirements:**
   The permittee shall inspect the control equipment weekly and make repairs as necessary to assure compliance.

5. **Specific Record Keeping Requirements:**
   Records of the lime and/or limestone processed shall be maintained for emissions inventory purposes.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

6. **Specific Reporting Requirements:**
   a) Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.676, the owner(s) or operator(s) of any emissions unit shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards of 40 CFR 60.672, including reports of opacity observations made using Method 9 to demonstrate compliance, and reports of observations using Method 22 to demonstrate compliance.

   b) See Section F.

7. **Specific Control Equipment Operating Conditions:**
   a) The partial enclosures shall be used as necessary to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices.

   b) Records regarding the maintenance of the partial enclosures shall be maintained.

   c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 18 (18) - Emergency Diesel Generator

Description:
Maximum Output: 150 kW
Rated capacity: 16.1 gallons/hour diesel fuel
Constructed on or before date: 1995

Applicable Regulations:
None

1. **Operating Limitations:**
   None

2. **Emission Limitations:**
   None

3. **Testing Requirements:**
   None

4. **Specific Monitoring Requirements:**
   See Section F.

5. **Specific Record Keeping Requirements:**
   Records of the fuel usage rate shall be maintained for emissions inventory purposes.

6. **Specific Reporting Requirements:**
   See Section F.

7. **Specific Control Equipment Operating Conditions:**
   NA

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 20 (17) - Existing Natural Draft Cooling Tower (with five chemical injection pumps and two circulating water pumps)

Description:

Control Equipment:	0.008% Drift Eliminators
Circulating Water Rate:	238,227 Gallons per Minute
Construction Commenced Date:	September 1990

Applicable Regulations:

401 KAR 63:010, Fugitive emissions
401 KAR 51:017, Prevention of Significant Deterioration of Air Quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

2. Emission Limitations:

a) Pursuant to 401 KAR 51:017, the cooling tower shall utilize 0.008% Drift Eliminators.

b) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

3. Testing Requirements:

None

4. Specific Monitoring Requirements:

The permittee shall monitor of total dissolved solids content of the circulating water on a monthly basis.

5. Specific Record Keeping Requirements:

a) The owner or operator shall maintain records of the manufacturer's design of the Drift Eliminators.

b) The owner or operator shall maintain records of water circulation rate and monthly records of the circulating water total dissolved solids content.

6. Specific Reporting Requirements:

See Section F for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

7. **Specific Control Equipment Operating Conditions:**
   a) Pursuant to 401 KAR 50:055, Section 5, the drift eliminators shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 401 KAR 63:010 and in accordance with manufacturer's specifications and/or standard operating practices.

   b) See Section E for further requirements.

SECTION B -EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Units: 25 – 30 (Emission Points 25 -30) - 6 *Combustion* Turbines (TC5 - TC10)

Description:
1763 mmBtu/hr maximum rated heat input capacity (@ -10 degrees F), each, 160 MW nominal rated capacity output each. General Electric 7FA natural gas-fired simple cycle combustion turbines equipped with dry low NO_x burners.
Units 25 & 26 (TC 5 & TC6) are proposed to be installed in April of 2002
Units 27 & 28 (TC 7 & TC8) are proposed to be installed in February of 2004
Units 29 & 30 (TC 9 & TC10) are proposed to be installed in April of 2004

The following requirements are applicable to each combustion turbine

Applicable Regulations:
401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, for emissions unit with a heat input at peak load equal to or greater than 10 mmBtu/hour for which construction commenced after October 3, 1977, and 40 CFR 60, Subpart A, General Provisions.
401 KAR 51:017, Prevention of significant deterioration of air quality
401 KAR 63:020, Potentially hazardous matter or toxic substances

1. **Operating Limitations:**
   a) The Permittee shall not operate any combustion turbine below load levels at which performance testing has proven compliance with emission limitations, except during periods of startup and shutdown. Startup and shutdown periods shall be limited to no more than two hours for each startup/shutdown event.
   b) The Permittee shall use only natural gas in the turbines.

2. **Emission Limitations:**
   a) Pursuant to 401 KAR 51:017, nitrogen oxides emission levels in the exhaust gas shall not exceed a hourly average of 12 ppm by volume at 15 percent oxygen on a dry basis, and an annual (12 month rolling) average of 9 ppm by volume at 15 percent oxygen on a dry basis, except during periods of startup, shutdown, or malfunction. Continuous compliance with this limit shall be demonstrated by a continuous emission monitor (CEM). Compliance with this limit constitutes compliance with the nitrogen oxide limit contained in 40 CFR 60 Subpart GG.

   b) Pursuant to 401 KAR 51:017, the fuel sulfur content due to the firing of natural gas shall not exceed 2.0 grains/100 SCF. Compliance with this limit shall be demonstrated by fuel sampling or vendor guarantees.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) Pursuant to 401 KAR 51:017, except during periods of startup, shutdown, or malfunction, the carbon monoxide emission level in the exhaust gas shall not exceed 9 ppm by volume at 15 % oxygen, on a dry basis, during any 3-hour average period. Continuous compliance with this limit shall be demonstrated by a continuous emission monitor (CEM).

d) Pursuant to 401 KAR 51:017, particulate emissions shall not exceed 19 pounds per hour.

e) The permittee shall not allow total formaldehyde emissions in the exhaust gas to exceed 10 tons during any consecutive 12- month period.

f) See Section D.

3. **Testing Requirements:**

a) Pursuant to 40 CFR 60.335(b), in conducting performance tests required by 40 CFR 60.8, the owner or operator shall use as test methods and procedures the test methods in Appendix A of Part 60 or other methods or procedures as specified in 40 CFR 60.335, except as provided for in 40 CFR 60.8(b).

b) Pursuant to 401 KAR 50:045, the owner or operator shall conduct an initial performance test on at least one of the turbines for sulfur dioxide, nitrogen oxides, carbon monoxide, particulate matter and formaldehyde, with use of a reference test method approved by the Division.

c) See General Conditions G(d)(5) and G(d)(6).

4. **Specific Monitoring Requirements:**

a) Pursuant to 401 KAR 52:020, Section 10, and 40 CFR 75.2, the permittee shall install, calibrate, maintain, and operate the nitrogen oxides Continuous Emissions Monitor (CEM). The nitrogen oxides CEM shall be used as the indicator of continuous compliance with the nitrogen oxides emission standard. Excluding the startup and shut down periods, if any (1) one-hour average exceeds the nitrogen oxides emission limitation, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and complete necessary control device/process/CEM repairs or take corrective action as soon as practicable.

b) Pursuant to 401 KAR 52:020, Section 10, the permittee shall monitor the quantity of natural gas, in millions of cubic feet, fired in each combustion turbine on a daily basis.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) Pursuant to 40 CFR 60.334(b), the owner or operator of any stationary turbine shall monitor sulfur content of the fuel being fired in the turbine. The frequency of determination of these values shall be as specified in the following approved Custom fuel monitoring schedule. The permittee will sample the natural gas for sulfur content every six months or use vendor guarantees that the gas contains 2.0 grains/100 SCF of sulfur or less as proof of natural gas quality.

d) Pursuant to 401 KAR 52:020, Section 10, to meet the periodic monitoring requirement for carbon monoxide the permittee shall use a continuous emission monitor (CEM). Excluding the startup and shut down periods, if any (3) three-hour average carbon monoxide value exceeds the standard, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and complete necessary process or CEM repairs or take corrective action as soon as practicable.

e) The permittee shall install, calibrate, operate, test, and monitor all continuous monitoring systems and monitoring devices in accordance with 40 CFR 60.13 or 40 CFR 75.10

f) The Permittee shall monitor the hours of operation of each combustion turbine on a daily basis.

g) The Permittee shall monitor the power output, in MW, of each combustion turbine on a daily basis.

5. <u>Specific Record Keeping Requirements</u>:

a) Pursuant to 40 CFR 60.7 (f), the owner or operator of the gas turbines shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems and devices; and all other information required by 40 CFR 60, Subpart A recorded in a permanent form suitable for inspection.

b) Records, including those documenting the results of each compliance test and all other records and reports required by this permit, shall be maintained for five (5) years pursuant to 401 KAR 52:020.

SECTION B -EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) The permittee shall maintain a log of all sulfur content measurements as required in the approved custom fuel sulfur-monitoring plan (Condition 4(c) above).

d) The permittee shall maintain a daily log of the natural gas, in millions of cubic feet, fired in each combustion turbine, for any consecutive twelve (12) month period.

e) The permittee shall maintain a daily log of all hours of operation for each combustion turbine, for any consecutive twelve (12) month period.

f) The permittee shall maintain a daily log of all power output, in MW, for each combustion turbine, for any consecutive twelve (12) month period.

6. **Specific Reporting Requirements:**

a) Pursuant to 40 CFR 60.7 (c), minimum data requirements which follow shall be maintained and furnished in the format specified by the Division. Owners or operators of facilities required to install continuous monitoring systems shall submit for every calendar quarter a written report of excess emissions (as defined in applicable sections) to the Division. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information:

1) The magnitude of the excess emissions computed in accordance with the 40 CFR 60.13 (h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the emissions unit. The nature and cause of any malfunction (if known), the corrective action taken or preventive measures adopted.

3) The date and time identifying each period during which continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Pursuant to 401 KAR 52:020 Section 10, monitoring requirement with CEM for nitrogen oxides, excess emissions are defined as any (1) one-hour period during which the average emissions (arithmetic average) exceed the applicable nitrogen oxides emission standard. These periods of excess emissions shall be reported quarterly. The nitrogen oxide CEM reports will be used in lieu of the water to fuel ratio requirements of 40 CFR 60.334(c).

c) Pursuant to 40 CFR 60.334(c), excess emissions of sulfur dioxide are defined as any daily period (or as otherwise required in an approved custom fuel sulfur monitoring plan) during which the sulfur content of the fuel being fired in the gas turbine(s) exceeds the limitations set forth in Subsection 2, Emission Limitations. These periods of excess emissions shall be reported quarterly.

d) Pursuant to 401 KAR 52:020, Section 10, monitoring requirement with CEM for carbon monoxide, excess emissions are defined as any (3) three-hour period during which the average emissions (arithmetic average) exceed the applicable carbon monoxide emission standard. These periods of excess emissions shall be reported quarterly.

7. **Specific Control Equipment Operating Conditions:**

a) The Dry Low-NO_x Burners shall be operated to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices.

b) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 31 - Unit 2 - Supercritical Pulverized Coal Fired Steam Electric Generating Unit Nominal rating 750 MW

Description:

Supercritical Pulverized Coal (SPC) Boiler, equipped with Selective Catalytic Reduction (SCR); Pulse Jet Fabric Filter (PJFF); Wet Flue Gas Desulfurization (WFGD); and Wet Electrostatic Precipitator (WESP).
ASTM Grade No. 2-D S15 fuel oil used for startup and stabilization.
Design capacity rating: 6,942 mmBtu/hour
Fuels include (i) Eastern bituminous coal, and (ii) a blend of Western sub bituminous coal and Eastern bituminous coal.
Construction Commence Date: Estimated 2006

Applicable Regulations:

401 KAR 51:017, Prevention of Significant Deterioration of Air Quality applicable to major construction or modification commenced after September 22, 1982;
401 KAR 51:160, NO_x requirements for large utility and industrial boilers; incorporating by reference 40 CFR 96;
401 KAR 52:060, Acid rain permits, incorporating by reference the Federal Acid Rain provisions as codified in 40 CFR Parts 72 to 78;
401 KAR 59:016, New Electric Utility Steam Generating Units;
40 CFR 60, Appendix F, Quality Assurance Procedures
401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units applicable to an emission unit with a capacity of more than 250 mmBtu per hour and commenced construction on or after September 19, 1978;
401 KAR 63:020, Potentially Hazardous Matter or Toxic Substances
40 CFR 64, Compliance Assurance Monitoring
40 CFR 75, Continuous Emission Monitoring
Compliance with 40 CFR 75, Continuous Emissions Monitoring, shall constitute compliance with the monitoring and quality assurance requirements of 401 KAR 59:016 and 40 CFR 60, Appendix F.

1. **Operating Limitations:**

   The owner or operator shall install control devices selected as BACT.

   - BACT for PM/PM_{10} is PJFF.
   - BACT for CO is good combustion controls.
   - BACT for H_2SO_4 mist is WESP.
   - BACT for fluorides (as HF) is WFGD.
   - BACT does not apply to NO_x and SO_2, however BACT type controls with similar emission levels will be installed with a SCR for NO_x emissions and WFGD for SO_2.
   - Only ASTM Grade No.2-DS15, with a sulfur content not to exceed 15 ppm shall be used for startup and stabilization.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. **Emission Limitations:**

a) Pursuant to 401 KAR 59:016, Section 3(1)(b), and 401 KAR 51:017, particulate and PM_{10} emissions shall not exceed 0.018 lb/mmBtu (filterable and condensable) of heat input based on the average of three one-hour tests. Pursuant to 401 KAR 59:016, Section 6(1), compliance with the 0.018lb/mmBtu (filterable and condensable) emission limitation shall constitute compliance with the 99% reduction requirement contained in 401 KAR 59:016, Section 3(1)(b).

b) Pursuant to 401 KAR 60:005, Section 3(1)(c) and 40 CFR 60.42a(c), [per proposed revisions to NSPS Subpart Da published in the Federal Register on February 28, 2005] filterable particulate emissions shall not exceed 0.015 lb/mmBtu of heat input based on a three-hour rolling average.

c) Pursuant to 401 KAR 59:016, Section 3(2), emissions shall not exceed twenty (20) percent opacity based on a six-minute average except that a maximum of twenty-seven (27) percent is allowed for not more than one (1) six (6) minute period per hour.

d) Pursuant to 401 KAR 51:017, Sulfur dioxide emissions shall not exceed 8.94 tons per calendar day and 3,263.1 tons per 12 consecutive months total.

e) Pursuant to 401 KAR 60:005, Section 3(1)(c) and 40 CFR 60.43a(i), [per proposed revisions to NSPS Subpart Da published in the Federal Register on February 28, 2005], sulfur dioxide emissions shall not exceed 2.0 lb/MWh gross energy output, based on a thirty (30) day rolling average. Pursuant to 401 KAR 59:016, Section 4, compliance with this limit shall constitute compliance with the 70% reduction requirement contained in 401 KAR 59:016, Section 4(1)(b).

f) Pursuant to 401 KAR 51:017, Carbon monoxide emissions shall not exceed 0.10 lbs/mmBtu based on a thirty day rolling average or 0.5 lbs/mmBtu on a three hour rolling average.

g) Pursuant to 401 KAR 51:017, Nitrogen oxides emissions shall not exceed 4.17 tons per calendar day and 1,506.72 tons per 12 consecutive months total.

h) Pursuant to 401 KAR 60:005, Section 3(1)(c) and 40 CFR 60.44a(e), [per proposed revisions to NSPS Subpart Da published in the Federal Register on February 28, 2005], nitrogen oxides emissions shall not exceed 1.0 lb/MWh gross energy output, based on a 30-day rolling average. Pursuant to 401 KAR 59:016, Section 5, compliance with this limitation shall constitute compliance with the 65% reduction requirement contained in 401 KAR 59:016, Section 5(2)(e).

i) Pursuant to 401 KAR 51:017, VOC emissions shall not exceed 0.0032 lbs/mmBtu based on a three (3) hour rolling average. Compliance with this limit shall be demonstrated by compliance with Subsection 2(f) above.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

j) Pursuant to 401 KAR 51:017, Sulfuric acid mist emissions shall not exceed 26.6 lbs/hr based on a three (3) hour rolling average.

k) Pursuant to 401 KAR 51:017, Fluorides emissions shall not exceed 1.55 lbs/hr based on a three (3) hour rolling average.

l) Mercury emissions shall not exceed 13 x 10^{-6} lbs/MWh (Gross output) based on a consecutive twelve (12) month rolling average. Compliance with this limit ensures compliance with 40 CFR 60.45a.

m) Lead emissions shall not exceed 0.55 tons per year based on a 12-month rolling total.

n) Pursuant to 401 KAR 63:020, the use of good combustion controls, PJFF, WFGD, and WESP shall be used for the control of organic toxic substances.

o) Compliance with emission limits in Subsections (a), (d), (f) and (i) shall constitute compliance with 401 KAR 63:020 with respect to toxic substances. Mercury is not regulated under 401 KAR 63:020 pursuant to 401 KAR 63:020 Section 1.

p) The above emission limitations shall not apply during periods of startup and shutdown. However, emissions during startup and shutdown shall be included in determining compliance with tons per year limits specified in this permit. Pursuant to 401 KAR 51:017, the owner or operator shall utilize good work and maintenance practices and manufacturer's recommendations to minimize emissions during, and the frequency and duration of, such events.

3. **Testing Requirements:**

a) Pursuant to 401 KAR 50:055, Section 2(1)(a) the owner or operator shall demonstrate compliance with the applicable emission standards within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the unit.

b) Pursuant to 401 KAR 50:045, Section 2 and 50:015, Section 1, the owner or operator shall determine the opacity of emissions from the stack by EPA Reference Method 9 as requested by the Division.

c) See Section D for further requirements.

4. **Specific Monitoring Requirements:**

a) Pursuant to 401 KAR 52:020, 401 KAR 59:016, Section 7, 401 KAR 51:017, 401 KAR 60:005, Section 3(1)(c), and 401 KAR 59:005, Section 4, the owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, carbon monoxide emissions, nitrogen oxides emissions, particulate matter emissions, mercury

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

emissions, and either oxygen or carbon dioxide diluents. Oxygen or carbon dioxide shall be monitored at each location where sulfur dioxide or nitrogen oxides emissions are monitored. The owner or operator shall ensure the continuous monitoring systems are in compliance with the requirements of 401 KAR 59:005, Section 4. Due to the wet nature of the stack, a continuous opacity monitor (COM) shall be located after the PJFF and before the WFGD as an indicator of performance.

b) Pursuant to 401 KAR 52:020, 401 KAR 59:016, Section 7(2) and 40 CFR 75.2, to meet the continuous monitoring requirement for sulfur dioxide, the owner or operator shall use a continuous emission monitor (CEM). If any 30 day rolling average (excluding the startup and shut down periods) or 8.94 tons per day limit for sulfur dioxide exceeds the limits, the owner or operator shall, as appropriate, initiate an inspection of the control equipment and/or the CEM system and make any necessary repairs as soon as practicable.

c) Pursuant to 401 KAR 52:020, 401 KAR 59:016, Section 7(3) and 40 CFR 75.2, to meet the continuous monitoring requirement for nitrogen oxide, the owner or operator shall use a CEM. If any 30 day rolling average (excluding the startup and shut down periods) or 4.17 tons per day limit for nitrogen oxide exceeds the limits, the owner or operator shall, as appropriate, initiate an inspection of the control equipment and/or the CEM system and make any necessary repairs as soon as practicable.

d) Pursuant to 401 KAR 52:020, Section 10 and 401 KAR 51:017, to meet the periodic monitoring requirement for CO, the owner or operator shall use a CEM.

e) Pursuant to 401 KAR 52:020, Section 10 and 401 KAR 51:017, to meet the periodic monitoring requirement for PM/PM_{10}, the owner or operator shall use a CEM.

f) Pursuant to 401 KAR 52:020, Section 10 and 40 CFR 60.49a(p), to meet the periodic monitoring requirement for mercury the owner or operator shall use a CEM.

g) Pursuant to 40 CFR 60.49a, 401 KAR 52:020 and 401 KAR 59:016, Section 7(5), all the CEM systems shall be operated and data shall be recorded during all periods of operation of the emissions units including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

h) Pursuant to 401 KAR 52:020 and 401 KAR 59:016, Section 7(6), when emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, the owner or operator shall obtain emission data by using other monitoring systems as approved by the Division or the reference methods as described in 401 KAR 59:016, Section 7(8) or other data substitution methods, including 40 CFR 75, to provide emission data for a minimum of eighteen hours in at least twenty-two out of thirty successive boiler operating days.

i) Pursuant to 401 KAR 59:016, Section 7(9), the following procedures shall be used to conduct monitoring system performance evaluations and calibration checks as required under 401 KAR 59:005, Section 4(3):

1. Reference Method 6 or 7, as applicable shall be used for conducting performance evaluations of sulfur dioxide and nitrogen oxides CEM systems.

2. Sulfur dioxide or nitrogen oxides, as applicable, shall be used for preparing calibration mixtures under Performance Specification 2 of Appendix B to 40 CFR 60 incorporated by reference in 401 KAR 50:015, or under 40 CFR 75.

3. The span value for the continuous monitoring system for measuring opacity shall be between sixty (60) and eighty (80) percent and the span value for the continuous monitoring system for measuring nitrogen oxides shall be 1,000 ppm, or span values as specified in 40 CFR 75, Appendix A.

4. The span value for the continuous monitoring system for measuring sulfur dioxide at the outlet of the control device shall be 50 percent of the maximum estimated hourly potential emissions of the fuel fired, or span values as specified in 40 CFR 75, Appendix A.

j) CAM Requirements. The owner or operator shall use Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_x), and particulate matter (PM/PM_{10}) Continuous Emissions Monitors (CEMs) as continuous compliance determination methods consistent with 40 CFR 64.4(d) for those specific parameters, and to demonstrate compliance with Best Available Control Technology (BACT) limits contained in this permit, as applicable.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Pursuant to 40 CFR 64.6, monitoring for H_2SO_4 and Fluoride is shown in the table below:

TABLE 1: CAM MONITORING APPROACH

Applicable CAM Requirement	H_2SO_4 Mist	Fluoride
General Requirements	26.6 lb/hr 3 hour rolling average	1.55 lb/hr 3 hour rolling average
Monitoring Methods and Location	SO_2 CEMs plus initial source test, WESP liquid flow rate, voltage, secondary currents and/or operating parameters, in conjunction with initial performance tests to establish excursion and exceedance, shall be monitored	SO_2 CEMs plus initial source test, weekly coal sampling (as received) with quarterly coal composites
Indicator Range	Initial source testing to establish correlation to SO_2 and coal quality, then establish SO_2 CEM and coal range appropriate	Initial source testing to establish correlation to SO_2 and coal quality, then establish SO_2 CEM and coal range appropriate
Data Collection Frequency	Continuous SO_2 CEM, weekly coal sampling (as received) with quarterly coal composites	Continuous SO_2 CEM, weekly coal sampling (as received) with quarterly coal composites
Averaging Period	3 hour rolling	3 hour rolling
Recordkeeping	Coal quality information will be kept in a designated hard copy or electronic archive, plus CEM data system records	Coal quality information will be kept in a designated hard copy or electronic archive, plus CEM data system records
QA/QC	WFGD/WESP will be maintained and operated in accordance with manufacturer specifications and recommendations	WFGD/WESP will be maintained and operated in accordance with manufacturer specifications and recommendations

5. **Specific Record Keeping Requirements:**

   a) Pursuant to 401 KAR 59:005, Section 3(4), the owner or operator of this unit shall maintain a record of applicable measurements, including CEM system, monitoring device, and performance testing measurements; all CEM system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems and devices; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Pursuant to 401 KAR 59:005, Section 3(2), the owner or operator of this unit shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility, any malfunction of the air pollution control equipment; or any period during which a CEM system or emission monitoring device is inoperative.

c) Pursuant to KAR 52:020, Section 10 and 401 KAR 50:045, Section 6, the owner or operator shall maintain the results of all compliance tests.

d) CAM Requirements

1. Pursuant to 40 CFR 64.9(b), the owner or operator shall record on a daily basis for the WFGD the following:

   a. The WFGD liquid pH in the reaction tank;
   b. Recycle pump amps and status.

2. Pursuant to 40 CFR 64.9(b), the owner or operator shall record, on a daily basis, voltages, or other parameters identified during the performance test for the WESP, as approved by the Division.

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 59:005, Section 3(3), minimum data requirements which follow shall be maintained and furnished in the format specified by the Division. Owners or operators of facilities required to install continuous monitoring systems shall submit for every calendar quarter a written report of excess emissions (as defined in applicable sections) to the Division. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information:

1. The magnitude of the excess emission computed in accordance with the 401 KAR 59:005, Section 4(8), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

2. All hourly averages shall be reported for sulfur dioxide and nitrogen oxides monitors. The hourly averages shall be made available in the format specified by the Division.

3. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The permittee shall determine the nature and cause of any malfunction (if known), and initiate the corrective action taken or preventive measures adopted.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. The date and time identifying each period during which continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

5. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

6. For sulfur dioxide and nitrogen oxides, all information listed in 401 KAR 59:016, Section 9(2)(a) through (i), shall be reported to the Division for each twenty-four (24) hour period.

7. If the minimum quantity of emission data as required by 401 KAR 59:016, Section 7 is not obtained for any thirty successive boiler operating days, the owner or operator shall report all the information listed in 401 KAR 59:016, Section 9(3) for that thirty (30) day period.

8. If any sulfur dioxide standards as specified in 401 KAR 59:016, Section 4(a and b) are exceeded during emergency conditions because of control system malfunction, the owner or operator shall submit a signed statement including all information as described in 401 KAR 59:016, Section 9(4).

9. For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator shall submit a signed statement pursuant to 401 KAR 59:016, Section 9(6) indicating if any changes were made in the operation of the emission control system during the period of data unavailability. Operations of control system and emissions units during periods of data unavailability are to be compared with operation of the control system and emissions units before and following the period of data unavailability.

10. The owner or operator shall submit a signed statement including all information as described in 401 KAR 59:016, Section 9(7).

11. Pursuant to 401 KAR 59:016, Section 9(8), for the purposes of the reports required under 401 KAR 59:005, Section 4, periods of excess emissions are defined as all six (6) minute periods during which the average opacity exceeds the applicable opacity standards as specified in 401 KAR 59:016, Section 3(2). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Division each calendar quarter. As the COM system is located after the PJFF as an indicator of performance for that device but before the WFGD which provides additional particulate control, in the event of an opacity exceedance, as indicated by COM data, the owner or operator may conduct a Method 9 test to verify that

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

actual opacity from the stack complies with the applicable opacity standard, in which case the owner or operator shall promptly complete any necessary repairs to the PJFF. Such events shall not be considered in excess of the applicable opacity standard for reporting or other purposes. The CEM systems for sulfur dioxide and nitrogen oxide shall be certified, operated and maintained in accordance with the applicable provisions of 40 CFR 75. compliance with which shall be deemed compliance with monitoring provisions of 40 CFR 60.49a.

b) Pursuant to 401 KAR 59:005, Section 3(3), the owner or operator shall report the number of excursions (excluding startup, shut down, malfunction data) above the opacity trigger level, date and time of excursions, opacity value of the excursions, and percentage of the COM data showing excursions above the opacity trigger level in each calendar quarter to the Division's Regional Office consistent with the reporting provisions of paragraph B.6.a.11..

c) CAM Requirements. Pursuant to 40 CFR 64.9(a) the owner or operator shall report the following information regarding its CAM plan according to the general reporting requirements specified in Section F.5. of this permit:

1. Number of exceedances or excursions;
2. Duration of each exceedance or excursion;
3. Cause of each exceedance or excursion;
4. Corrective actions taken on each exceedance or excursion;
5. Number of monitoring equipment downtime incidents;
6. Duration of each monitoring equipment downtime incident;
7. Cause of each monitoring equipment downtime incident;
8. Description of actions taken to implement a quality improvement plan and upon completion of the quality improvement plan, documentation that the plan was completed and reduced the likelihood of similar excursions or exceedances.
9. The permittee shall take a sample of fuel "as received" upon delivery schedule to the PCs. The samples taken shall be uniformly mixed to form a composite sample analyzed to determine fluoride content on a quarterly basis. This data, along with the baseline data established during the initial compliance and subsequent tests, shall be used to demonstrate compliance with the emission limits for HF.

d) The permittee shall report quarterly the twelve (12) month rolling total sulfur dioxide and nitrogen oxides emissions.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

7. **Specific Control Equipment Operating Conditions:**

   a) Pursuant to 401 KAR 50:055, Section 2 (5), the SCR, PJFF, WFGD, and WESP, shall be operated to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices.

   b) Pursuant to 401 KAR 59:005, Section 3(4), records regarding the maintenance of the control equipment shall be maintained.

   c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 32 - Auxiliary Steam Boiler D

Description:

40 mmBtu/hr · ASTM Grade No. 2-D S15 fired auxiliary steam boiler
Construction Commenced Date: Estimated 2006

Applicable Regulations:

40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, incorporated by reference in 401 KAR 60:005, Section 3(1)(e).
401 KAR 59:015, New Indirect Heat Exchangers.
40 CFR 63, Subpart DDDDD
401 KAR 63:020, Potentially Hazardous Matter or Toxic Substances.
40 CFR 60, Appendix F, Quality Assurance Procedures
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**

   The auxiliary steam boiler, except for testing purposes, shall only operate during periods when Unit 31 is operating at less than 50 percent load. The auxiliary boiler shall not operate more than 1,000 hours in any twelve (12) consecutive months.

2. **Emission Limitations:**

   a) Pursuant to 401 KAR 60:005, Section 3(1)(e), 401 KAR 59:015, Section 4(1)(c), 401 KAR 51:017, 40 CFR 60.43c(e) [per proposed revised NSPS Subpart Dc as published in the Federal Register on February 28, 2005], and 40 CFR 63 Subpart DDDDD Table 1, particulate emissions shall not exceed 0.03 lb/mmBtu heat input.

   b) Pursuant to 401 KAR 60:005, Section 3(1)(e) and 401 KAR 59:015, Section 4(2)(a), emissions from the auxiliary steam boiler shall not exceed twenty (20) percent opacity based on a six-minute average except that a maximum of twenty-seven (27) percent is allowed for not more than one (1) six (6) minute period per hour.

   c) Pursuant to 401 KAR 60:005, Section 3(1)(b); 401 KAR 59:015, Section 5(1)(b); and 401 KAR 51:017, the fuel oil used must meet the sulfur content standards in ASTM Grade No. 2-D S15 and cannot exceed a sulfur content of 15 ppm.

   d) Pursuant to 401 KAR 51:017 and 40 CFR 63 Subpart DDDDD Table 1, carbon monoxide emissions shall not exceed 400 ppm by volume on a dry basis corrected to 3 percent oxygen and a 3-hour average.

   e) Pursuant to 40 CFR 63 Subpart DDDDD Table 1, hydrogen chloride emissions shall not exceed 0.0005 lbs/mmBtu of heat input.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

3. **Testing Requirements:**

a) Pursuant to 401 KAR 59:005, Section 2(1) and 401 KAR 59:015, Section 8, the owner or operator shall demonstrate compliance with the applicable emission standards within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility.

b) Pursuant to 40 CFR 63.7506, a performance test to demonstrate compliance with the carbon monoxide and hydrogen chloride emission limits is not required. However the following requirements must be met.

1. To demonstrate initial compliance, a signed statement in the Notification of Compliance Status report that indicates that the unit burns only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels.

2. To demonstrate continuous compliance, records must be kept that demonstrate that the unit burned only liquid fossil fuels other than residual oil, either alone or in combination with gaseous fuels. A signed statement must be included in each semiannual compliance report that indicates that the unit burned only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels, during the reporting period.

c) Pursuant to 401 KAR 59:015, Section 8(1)(f), if the unit has operated during the previous 12 consecutive months, the owner or operator shall determine the opacity of emissions from the stack by EPA Reference Method 9 upon request by the Division.

d) See Section D for further requirements.

4. **Specific Monitoring Requirements:**

a) The owner or operator shall monitor the hours of operation during each twelve (12) consecutive months.

b) To demonstrate continuing compliance with the fuel oil sulfur content limitation, monitoring of operations shall consist of, on an as-received basis, fuel supplier certification of the sulfur content of the fuel oil to be combusted. The fuel supplier certification shall include the name of the oil supplier, sulfur content, and a statement that the oil complies with the specifications under the definition for distillate oil in 401 KAR 60:005

c) The fuel oil sulfur content and heating value shall be determined for the No. 2 fuel oil, as received, by fuel supplier certification.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

5. **Specific Record Keeping Requirements:**

a) Pursuant to 401 KAR 59:005, Section 3(4), the owner or operator of the indirect heat exchanger shall maintain a file of all measurements and performance testing measurements required by 401 KAR 59:005 recorded in a permanent form suitable for inspection.

b) Pursuant to 401 KAR 59:005, Section 3(2), the owner or operator of this unit shall maintain the records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility.

c) The owner or operator shall maintain the results of all compliance tests.

d) The owner or operator shall maintain records of hours of operation during each twelve (12) consecutive months.

e) Pursuant to 401 KAR 59:005, Section 3 (4), the owner or operator of the indirect heat exchanger shall maintain a file of all measurements, including monthly No. 2 fuel oil usage. The owner or operator shall maintain a file of the fuel supplier certification; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection. The file shall be retained for at least five (5) years following the date of such measurements, maintenance, reports, and records.

f) Records of the No. 2 fuel oil used shall be maintained.

6. **Specific Reporting Requirements:**

a) Pursuant to 401 KAR 60:005, Section 3(1)(e), the owner or operator shall follow the applicable Reporting and Recordkeeping requirements specified in 40 CFR 60.48c.

b) Pursuant to 40 CFR 63 Subpart DDDDD, the owner or operator shall make notifications required by 40 CFR 63.7545.

c) Pursuant to 40 CFR 63 Subpart DDDDD, the owner or operator shall submit reports required by 40 CFR 63.7550.

7. **Specific Control Equipment Operating Conditions:**

a) Pursuant to 401 KAR 50:055, Section 5, the auxiliary steam boiler shall be operated in accordance with manufacturer's specifications and / or standard operating practices.

b) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 33 - Backup Diesel Generator

Description:
12.5 mmBtu/hr - ASTM Grade No. 2-D S15 fuel oil-fired Backup Generator without oxidation catalyst or Non-Selective Catalytic Reduction (NSCR).
Construction Commenced Date: Estimated 2006

Applicable Regulations:
401 KAR 63:002, incorporating by reference 40 CFR 63, Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:
Pursuant to 401 KAR 51:017, the backup diesel generator, except for testing purposes, shall only operate during periods when Unit 31 is operating less than 50 percent load. The backup diesel generator shall not operate more than 1,000 hours per twelve (12) consecutive months.

2. Emission Limitations:
Pursuant to 401 KAR 63:002, formaldehyde concentration in the exhaust shall not exceed 580 ppbvd at 15 percent O_2 except during periods of startup, shutdown, and malfunction.

3. Testing Requirements:

a) Pursuant to 401 KAR 63:002, the owner or operator shall demonstrate compliance with the applicable emission standards upon startup.

b) Pursuant to 401 KAR 63:002, the average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs shall not exceed the formaldehyde emission limit specified in 2.

c) Pursuant to 401 KAR 63:002, semiannual performance tests for formaldehyde will be performed to determine compliance. If compliance is demonstrated with two consecutive semiannual tests, subsequent compliance tests shall be performed on an annual basis, unless otherwise approved by the Division.

d) See Section D for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. Specific Monitoring Requirements:

a) Pursuant to 401 KAR 63:002, the owner or operator shall install, calibrate, maintain, and operate a continuous parameter monitoring system, or alternative method, as allowed by regulation. The operating parameters are to be approved by the Division.

b) See Section D for further requirements.

5. Specific Record Keeping Requirements:

a) The owner or operator shall maintain the results of all compliance tests.

b) The owner or operator shall maintain records of hours of operation during each twelve (12) consecutive month period.

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 60:005, Section 3(1)(e), the owner or operator shall follow the applicable Reporting and Recordkeeping requirements specified in 40 CFR 60.48c.

b) Pursuant to 40 CFR 63 Subpart ZZZZ, the owner or operator shall make notifications required by 40 CFR 63.6645.

c) Pursuant to 40 CFR 63 Subpart ZZZZ, the owner or operator shall submit reports required by 40 CFR 63.6645.

7. Specific Control Equipment Operating Conditions:

None

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 34, 35 - Fossil Fuel Handling Operations-Coal Piles (FUGITIVES)

Description:
Construction Commenced Date:
Estimated 2006

Active Northwest Fossil Fuel Pile "A"	Fuel Pile Storage and Maintenance Activities
Active Northeast Fossil Fuel Pile "B"	Fuel Pile Storage and Maintenance Activities

Control Equipment

Active Northwest Fossil Fuel Pile "A"	Compaction and Water Suppression
Active Northeast Fossil Fuel Pile "B"	Compaction and Water Suppression

Applicable Regulations:
401 KAR 63:010, Fugitive emissions.
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**
   a) Pursuant to 401 KAR 51:017 and 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, as needed, but not be limited to the following:

      1. Application and maintenance of asphalt, application of water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dusts;

      2. Operation of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling;

      3. The maintenance of paved roadways.

      4. The prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or other earth moving equipment or erosion by water;

      5. Installation and use of compaction or other measures to suppress the dust emissions during handling.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

c) No one shall allow earth or other material being transported by truck or earth moving equipment to be deposited onto a paved street or roadway, pursuant to 401 KAR 63:010, Section 4.

d) Pursuant to 401 KAR 51:017, the owner or operator shall apply compaction and water suppression control methods as BACT.

2. Emission Limitations:
None

3. Testing Requirements:
40 CFR 60 Appendix A, Reference Method 22 shall be used to determine opacity upon request by the Division.

4. Specific Monitoring Requirements:

a) The owner or operator shall perform a qualitative visual observation on a weekly basis and maintain a log of the observations and corrective actions.

b) See Section F for further requirements.

5. Specific Record Keeping Requirements:

a) Records of the fossil fuels received and processed shall be maintained for emissions inventory purposes.

b) Annual records estimating the tonnage hauled on plant roadways shall be maintained for emissions inventory purposes.

c) The owner or operator shall maintain a log of the date, time and results of the monitoring required in Subsection 4 above.

6. Specific Reporting Requirements:
See Section F for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

7. **Specific Control Equipment Operating Conditions:**

   a) Pursuant to 401 KAR 50:055, Section 5 and 401 KAR 51:017, the dust water suppressant system for the coal stockpile operations shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 401 KAR 63:010, and in accordance with manufacturer's specifications and standard operating practices.

   b) Plant roadways shall be paved and controlled with water as necessary to comply with 401 KAR 63:010.

   c) Pursuant to 401 KAR 59:005, Section 3(4), records regarding the maintenance of the control equipment shall be maintained.

   d) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 36, 37, 38, 39 -- Fossil Fuel Handling Operations, Dust Control Devices, and Associated Systems (Please refer to Units 7, 8 and 9 for additional existing fossil fuel handling operation information)

Description:

Construction Commenced Date: on or Before 1990

Continuous Barge Unloader –
One Barge Unloader Bin

Conveyor System -

Conveyor Belt A:	From Continuous Barge Unloader to Conveyor B
Conveyor Belt B:	From Conveyor A to Transfer House/Conveyor C
Conveyor Belt C:	From Transfer House to Coal Sample House Bin
Conveyor Belt D:	From Coal Sample House Bin to Conveyor E1 or S
Conveyor Belt E1:	From Conveyor D to Active Storage and Crusher House
Conveyor Belts F1 & F2:	From Crusher House to Conveyors G1 & G2
Conveyor Belts G1 & G2:	From Conveyors F1 & F2 to Unit 1 & 2 Coal Silos
Conveyor Belt S:	From Conveyor D to One Inactive Fossil Fuel Pile
Reclaim Hopper & Conveyor Belt R1:	From One Inactive Fossil Fuel Pile to Crusher House

Crusher House -
Two crushers, fossil fuel crusher bin, and fuel blender: Crusher House Activities

Construction Commenced Date: Estimated 2006

Power House –
Six Unit 2 fossil fuel silos: Unit 2 Coal Storage

Conveyor System –

Conveyor Belt E2:	From Unit 2 Active Coal Piles "A & B" to Crusher House
Fuel Blending System:	From Active Coal Storage to Conveyor E2

Control Equipment

EU#36-Barge Unloader Dust Collector (CDC01):	Conveyors A&B
EU#37-U/R Reclaim Vault Dust Collector (CDC02):	Drop from Coal Feeders 1-7 to Conveyor E2
EU#38-Coal Crusher Dust Collector (CDC03):	Coal Crusher House Activities
EU#39-Unit 2 Coal Silo Dust Collector (CDC04):	Conveyors F1&2 and Drop to G1&2; Unit 2 Coal Silos

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Description

Conveyors:	Enclosures, water suppression, low drops, and baghouse filters, hoods
Conveyor S:	Stackout Chute

Operating Rate–

Continuous Barge Unloader	Transfer Rates
One Barge Unloader	5,500 tons/hour

Conveyor System -

Conveyor Belt A:	5,500 tons/hour
Conveyor Belt B:	5,500 tons/hour
Conveyor Belt C:	5,500 tons/hour
Conveyor Belt D:	3,000 tons/hour
Conveyor Belt E1:	2,640 tons/hour
Conveyor Belt E2:	1,320 tons/hour
Conveyor Belts F1 & F2:	1,320 tons/hour
Conveyors G1 & G2	1.320 tons/hour
Conveyor Belt S:	1,650 tons/hour
Reclaim Hopper & Conveyor Belt R1:	1,320 tons/hour
Unit2 Fuel Blending System:	800 tons/hour

Crusher House -

Two crushers, fossil fuel crusher bin, and fuel blender: 3,600 tons/hour

Power House -

Six unit 2 fossil fuel silos: 800 tons/hour

Applicable Regulations:

401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants for units commenced after October 24, 1974

401 KAR 51:017, Prevention of Significant Deterioration of Air Quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**

   Pursuant to 401 KAR 51:017, the owner or operator shall install the following dust collectors as BACT:

   a) Barge Unloader Dust Collector

   b) U/R Reclaim Vault Dust Collector

   c) Coal Crusher Dust Collector

   d) Unit 2 Coal Silo Dust Collector

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED

2. **Emission Limitations:**
   a) Pursuant to 401 KAR 60:005 incorporating by reference 40 CFR 60.252, the owner or operator subject to the provisions of this regulation shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

   b) Pursuant to 401 KAR 51:017, the dust collectors utilized shall exhibit a particulate design control efficiency of at least 99%.

3. **Testing Requirements:**
   Pursuant to 401 KAR 60:005, Section 3(1)(ff) incorporating by reference, 40 CFR 60.254, EPA Reference Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity upon request by the Division.

4. **Specific Monitoring Requirements:**
   The owner or operator shall perform a qualitative visual observation of the opacity of emissions from each stack on a weekly basis and maintain a log of the observations. If visible emissions from any stack are seen, the owner or operator shall determine the opacity of emissions by Reference Method 9 and instigate an inspection of the control equipment making any necessary repairs.

5. **Specific Record Keeping Requirements:**
   a) The owner or operator shall maintain the records of amount of coal received and processed.

   b) The owner or operator shall maintain the results of all compliance tests. The owner or operator shall record each week, the date and time of each observation and opacity of visible emissions monitoring. In case of exceedances, the owner or operator must record the reason (if known) and the measures taken to minimize or eliminate exceedances.

6. **Specific Reporting Requirements:**
   See Section F for further requirements.

7. **Specific Control Equipment Operating Conditions:**
   a) Pursuant to 401 KAR 50:055, Section 5, the enclosures/partial enclosures, baghouses, bin vent filters, conveyor systems, fuel blending operations, fossil fuel storage silos, and stackout chute shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 40 CFR 60, Subpart Y and in accordance with manufacturer's specifications and/or standard operating practices.

   b) Pursuant to 401 KAR 59:005, Section 3(4), records regarding the maintenance and use/operation of the control equipment listed in 7(a) shall be maintained.

   c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED

Emissions Units: 40 - Limestone Handling Operations, Dust Control Devices, and Associated Systems

Description:
Construction Commenced Date: Estimate
2006

Stockpile/Stackout Operations:

Active Limestone Pile	Limestone Storage Activities
Active Limestone Pile Reclaimer	Limestone Reclaim Activities

Control Equipment

Active Limestone Pile	Low Drop/Enclosure/Dust Collector (LDC01)
Active Limestone Pile Reclaimer	Enclosure/Dust Collector (LDC01)
EU#40-Limestone Dust Collector (LDC01)	Conveyor B onto Active Pile and Active Pile Reclaimer onto Conveyor C

Operating Rate

Active Limestone Pile	N/A
Active Limestone Pile Reclaimer	200 tons/hour

Applicable Regulations:
401 KAR 60.670, New Nonmetallic Mineral Processing Plants, incorporating by reference 40 CFR 60, Subpart OOO – Nonmetallic Mineral Processing Plants, applies to the emissions unit listed above, commenced after August 31, 1983
401 KAR 51:017, Prevention of Significant Deterioration of Air Quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**
   Pursuant to 401 KAR 51:017, the owner or operator shall install a dust collector as BACT.

2. **Emission Limitations:**

   a) Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.672(e), no owner or operator shall cause to be discharged into the atmosphere from any building enclosing any transfer point on a conveyor belt or any other emissions unit any visible fugitive emissions.

   b) Pursuant to 401 KAR 51:017 and 401 KAR 60:670, emissions of particulate shall be controlled by dust collectors.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) Pursuant to 401 KAR 60:670, specifically 40 CFR 60.672(a), stack emissions of particulate shall not exceed 0.05 gr/dscm and shall not exhibit greater than 7% opacity.

d) Pursuant to 401 KAR 60:607, specifically 40 CFR 60.672(b), fugitive emissions of particulate shall not exhibit greater than 10% opacity.

3. **Testing Requirements:**
In determining compliance with 401 KAR 60:670, incorporating by reference 40 CFR 60.672(e), for fugitive emissions from buildings, the owner(s) or operator(s) shall determine fugitive emissions while all emissions units are operating in accordance with EPA Reference Method 22, annually.

4. **Specific Monitoring Requirements:**
The owner or operator shall inspect the control equipment weekly and make repairs as necessary to assure compliance.

5. **Specific Record Keeping Requirements:**
Records of the limestone processed shall be maintained for emissions inventory purposes.

6. **Specific Reporting Requirements:**

a) Pursuant to 401 KAR 60:670, incorporating by reference 40 CFR 60.676, the owner(s) or operator(s) of any emissions unit shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards of 40 CFR 60.672 including reports of observations using Method 22 to demonstrate compliance.

b) See Section F for further requirements.

7. **Specific Control Equipment Operating Conditions:**

a) Pursuant to 401 KAR 50:055, Section 5, the dust collector and enclosures shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 40 CFR 60, Subpart OOO and in accordance with manufacturer's specifications and/or standard operating practices.

b) Pursuant to 401 KAR 50:050, Section 1, records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED

Unit: 41 - **Linear Mechanical Draft Cooling Tower (11 cells)**

Description:

Control Equipment:	0.0005% Drift Eliminators
Circulating Water Rate:	173,120 Gallons per Minute
Construction Commenced Date:	Estimated 2006

Applicable Regulations:

401 KAR 63:010, Fugitive emissions

401 KAR 51:017, Prevention of Significant Deterioration of Air Quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**
   a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

   b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

2. **Emission Limitations:**
   a) Pursuant to 401 KAR 51:017, the cooling tower shall utilize 0.0005% Drift Eliminators.

   b) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

3. **Testing Requirements:**
   Initial performance test to verify drift percent achieved by the drift eliminator will be conducted based on the Cooling Technology Institute (CTI) Acceptance Test Code (ATC) # 140

4. **Specific Monitoring Requirements:**

   The permittee shall monitor total dissolved solids content of the circulating water on a monthly basis.

5. **Specific Record Keeping Requirements:**
   a) The owner or operator shall maintain records of the manufacturer's design of the Drift Eliminators.

   b) The owner or operator shall maintain records of maximum pumping capacity and monthly records of the total dissolved solids content.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

6. **Specific Reporting Requirements:**
   See Section F for further requirements.

7. **Specific Control Equipment Operating Conditions:**
   a) Pursuant to 401 KAR 50:055, Section 5, the drift eliminators shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 401 KAR 63:010 and in accordance with manufacturer's specifications and/or standard operating practices.

   b) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED

Unit: 42 - Fly Ash Storage Silo and Dust Control Device

Description:

Construction Commenced Date: Estimate
2006

Fly Ash Silo Bins	Fly Ash Storage Activities

Control Equipment

EU#42-Fly Ash Dust Collector (FDC01)	Fly Ash from Units 1 and 31 into Fly Ash Silo Bins and Fly Ash from Fly Ash Silo Bins into Dry Bulk Trailers with Tractors

Operating Rate

Fly Ash Silo Bins	Material Throughput: 33 tons/hour each

Applicable Regulations:

401 KAR 59:010, New Process Operations, applicable to an emission unit, which commenced on or after 1972

401 KAR 51:017, Prevention of Significant Deterioration of Air Quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

Pursuant to 401 KAR 51:017, the owner or operator shall install a dust collector as BACT.

2. Emission Limitations:

a) Pursuant to 401 KAR 59:010, Section 3(1), the owner or operator shall not cause to be discharged into the atmosphere from any of the above listed units emissions greater than twenty (20) percent opacity.

b) Pursuant to 401 KAR 59:010, particulate matter emissions from the bin dust collector shall not exceed [$3.59 (P)^{0.62}$] lbs/hr based on a three-hour average, where P is the material throughput rate in tons/hour.

3. Testing Requirements:

None

4. Specific Monitoring Requirements:

The owner or operator shall perform a qualitative visual observation of the opacity of emissions from the stack on a weekly basis and maintain a log of the observations. If visible emissions from any stack included in this emission unit are seen, then the owner or operator shall determine the opacity of emissions by Reference Method 9 and perform an inspection of the control equipment for any necessary repairs.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED

5. Specific Record Keeping Requirements:

a) The owner or operator shall maintain the records of amount of fly ash processed.

b) Pursuant to 401 KAR 59:005, Section 3(4), the owner or operator shall maintain the results of all compliance tests and calculations.

c) The owner or operator shall record each week the date, time and opacity of the visible emissions monitoring. In case of an exceedance, the owner or operator must record the reason (if known) and the measures taken to minimize or eliminate the exceedance.

6. Specific Reporting Requirements:

See Section F for further requirements.

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 50:055, Section 5, the dust collector equipment shall be maintained and operated to ensure the emission unit is in compliance with applicable requirements of 401 KAR 59:010 and in accordance with manufacturer's specifications and/or standard operating practices

b) Pursuant to 401 KAR 59:005, Section 3(4), records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

SECTION C - INSIGNIFICANT ACTIVITIES

The following listed activities have been determined to be insignificant activities for this source pursuant to 401 KAR 52:020, Section 6. While these activities are designated as insignificant the permittee must comply with the applicable regulation and some minimal level of periodic monitoring may be necessary. Process and emission control equipment at each insignificant activity subject to a general applicable regulation shall be inspected monthly and qualitative visible emission evaluation made. The results of the inspections and observations shall be recorded in a log, noting color, duration, density (heavy or light), cause and any conservative actions taken for any abnormal visible emissions.

	Description	Generally Applicable Regulation
1.	Two station #2 fuel oil tanks, each 100,000 gallons (401 KAR 59:050), and auxiliary boiler day tank storing #2 fuel oil with a size of 16,000 gallons. General recordkeeping requirements - 40 CFR 60.116b(a) and (b)	401 KAR 59:050 40 CFR 60.116b(a) and (b)
2.	Metal degreaser using a maximum throughput of 832 gallons/year solvent.	NA
3.	3,000 gallon unleaded gasoline storage tank.	NA
4.	3,000 gallon diesel storage tank.	NA
5.	1,100 gallon used oil storage tank.	NA
6.	1,100 gallon #1 fuel oil tank.	NA
7.	Fly ash collection system	401 KAR 59:010
8.	Infrequent evaporation of boiler cleaning solutions.	NA
9.	Infrequent burning of De Minimis quantities of used oil for energy recovery.	NA
10.	Paved and Unpaved Roads.	401 KAR 63:010
11.	Preheater (for CTs Units 9 & 10) Max. Heat Input 10.9 mmBtu/hr.	401 KAR 59:010
12.	Preheater (for CTs Units 11 &12) Max. Heat Input 10.9 mmBtu/hr.	401 KAR 59:010
13.	Preheater (for CTs Units 13 & 14) Max. Heat Input 10.9 mmBtu/hr.	401 KAR 59:010
14.	Gypsum Storage Piles	401 KAR 63:010
15.	Coal and Limestone Storage Piles (Inactive Outdoor Piles)	401 KAR 63:010
16.	Bottom Ash and Debris Collection Basin	401 KAR 63:010
17.	Bottom Ash Reclaim Operation	401 KAR 63:010
18.	Three dry bulk fly ash transport trailers	401 KAR 59:010
19.	Maintenance Shop Activities	NA
20.	Miscellaneous Water Storage Tanks	NA
21.	Anhydrous Ammonia Storage Tanks	401 KAR 68
22.	Fire Water Pump Engines	NA
23.	Three dry bulk fly ash transport trailers	401 KAR 59:010

SECTION D - SOURCE EMISSION LIMITATIONS AND TESTING REQUIREMENTS

1. As required by Section 1b of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26; compliance with annual emissions and processing limitations contained in this permit, shall be based on emissions and processing rates for any twelve (12) consecutive months.

2. Compliance with visible emission limitations for indirect heat exchanger Unit 01, shall be determined by using EPA reference Method 9. Alternatively, the owner or operator may use COM in determining compliance with opacity.

3. Conditions in permit V-02-043 Revision 1 and PSD permit V-01-012 were merged into one source-wide permit. Limitations from both permits were combined into this permit.

4. Nitrogen oxides, sulfur dioxide, PM (filterable), formaldehyde, visible emissions (opacity), mercury, and carbon monoxide emissions, measured by applicable reference methods, or an equivalent or alternative method specified in 40 C.F.R. Chapter I, or by a test method specified in the state implementation plan shall not exceed the respective limitations specified herein.

5. Unit 31 shall be performance tested initially for compliance with the emission standards for PM/PM_{10} (filterable and condensable), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon monoxide (CO), VOCs, mercury, and H_2SO_4, lead and fluorides by applicable reference methods, or by equivalent or alternative test methods specified in this permit or approved by the cabinet or U.S. EPA. For Unit 31 annual performance tests for PM/PM_{10}, VOCs, and lead will be conducted.

6. After the initial compliance test for Unit 31, and CEMS/COMs certification as stated in 401 KAR 50:055, continuing compliance with the emission standards shall be determined by continuous monitoring systems for NO_x, CO, PM/PM_{10}, mercury, and SO_2. Continuing compliance with the emission standards for H_2SO_4 mist and Fluorides shall be determined by following provision of the CAM plan in Section B of this permit.

7. The 12-month rolling total emissions from Units 31, 32, 33, and emergency fire water pump engine shall be less than: 1,523 NO_x tons, 3,264 SO_2 tons, and 0.55 lead tons.

8. The permittee shall evaluate the relationship between CO and VOC during the initial and annual stack tests. Results of this evaluation shall be submitted to the Division within sixty days after submitting the annual test results.

SECTION E - SOURCE CONTROL EQUIPMENT REQUIREMENTS

Pursuant to 401 KAR 50:055, Section 2(5), at all times, including periods of startup, shutdown and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

SECTION F - MONITORING, RECORD KEEPING, AND REPORTING REQUIREMENTS

1. When continuing compliance is demonstrated by periodic testing or instrumental monitoring, the permittee shall compile records of required monitoring information that include:
   a. Date, place as defined in this permit, and time of sampling or measurements.
   b. Analyses performance dates;
   c. Company or entity that performed analyses;
   d. Analytical techniques or methods used;
   e. Analyses results; and
   f. Operating conditions during time of sampling or measurement.

   [Section 1b (IV)1 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

2. Records of all required monitoring data and support information, including calibrations, maintenance records, and original strip chart recordings, and copies of all reports required by the Division for Air Quality, shall be retained by the permittee for a period of five years and shall be made available for inspection upon request by any duly authorized representative of the Division for Air Quality [Sections 1b(IV) 2 and 1a(8) of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

3. In accordance with the requirements of 401 KAR 52:020 Section 3(1)h the permittee shall allow authorized representatives of the Cabinet to perform the following during reasonable times:
   a. Enter upon the premises to inspect any facility, equipment (including air pollution control equipment), practice, or operation;
   b. To access and copy any records required by the permit:
   c. Inspect, at reasonable times, any facilities, equipment (including monitoring and pollution control equipment), practices, or operations required by the permit. Reasonable times are defined as during all hours of operation, during normal office hours; or during an emergency.
   d. Sample or monitor, at reasonable times, substances or parameters to assure compliance with the permit or any applicable requirements.
   e. Reasonable times are defined as during all hours of operation, during normal office hours; or during an emergency.

4. No person shall obstruct, hamper, or interfere with any Cabinet employee or authorized representative while in the process of carrying out official duties. Refusal of entry or access may constitute grounds for permit revocation and assessment of civil penalties.

5. Summary reports of any monitoring required by this permit, other than continuous emission or opacity monitors, shall be submitted to the Regional Office listed on the front of this permit at least every six (6) months during the life of this permit, unless otherwise stated in this permit. For emission units that were still under construction or which had not commenced operation at the end of the 6-month period covered by the report and are subject to monitoring requirements in this permit, the report shall indicate that no monitoring was performed during

SECTION F - MONITORING, RECORD KEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

the previous six months because the emission unit was not in operation [Section 1b (V)1 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

6. The semi-annual reports are due by January 30th and July 30th of each year. Data from the continuous emission and opacity monitors shall be reported to the Technical Services Branch in accordance with the requirements of 401 KAR 59:005, General Provisions, Section 3(3). All reports shall be certified by a responsible official pursuant to 401 KAR 52:020 Section 23. All deviations from permit requirements shall be clearly identified in the reports.

7. In accordance with the provisions of 401 KAR 50:055, Section 1 the owner or operator shall notify the Regional Office listed on the front of this permit concerning startups, shutdowns, or malfunctions as follows:
   a. When emissions during any planned shutdowns and ensuing startups will exceed the standards, notification shall be made no later than three (3) days before the planned shutdown, or immediately following the decision to shut down, if the shutdown is due to events which could not have been foreseen three (3) days before the shutdown.
   b. When emissions due to malfunctions, unplanned shutdowns and ensuing startups are or may be in excess of the standards, notification shall be made as promptly as possible by telephone (or other electronic media) and shall be submitted in writing upon request.

8. The owner or operator shall report emission related exceedances from permit requirements including those attributed to upset conditions (other than emission exceedances covered by Section F.7. above) to the Regional Office listed on the front of this permit within *30 days*. Other deviations from permit requirements shall *be included in the semiannual report required by Section F.6* [Section 1b (V) 3, 4. of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

9. Pursuant to 401 KAR 52:020, Permits, Section 21, the permittee shall certify compliance with the terms and conditions contained in this permit, by completing and returning a Compliance Certification Form (DEP 7007CC) (or an alternative approved by the regional office) to the Regional Office listed on the front of this permit and the U.S. EPA in accordance with the following requirements:
   a. Identification of the term or condition;
   b. Compliance status of each term or condition of the permit;
   c. Whether compliance was continuous or intermittent;
   d. The method used for determining the compliance status for the source, currently and over the reporting period, and
   e. For an emissions unit that was still under construction or which has not commenced operation at the end of the 12-month period covered by the annual compliance certification, the permittee shall indicate that the unit is under construction and that compliance with any applicable requirements will be demonstrated within the timeframes specified in the permit.

SECTION F - MONITORING, RECORD KEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

f. The certification shall be postmarked by January 30th of each year. Annual compliance certifications should be mailed to the following addresses:

Division for Air Quality
Florence Regional Office
8020 Veterans Memorial drive
Suite 110, Florence, KY 41042

U.S. EPA Region 4
Air Enforcement Branch
Atlanta Federal Center
61 Forsyth St. Atlanta, GA 30303-8960

Division for Air Quality
Central Files
803 Schenkel Lane
Frankfort, KY 40601

10. In accordance with 401 KAR 52:020, Section 22, the permittee shall provide the Division with all information necessary to determine its subject emissions within thirty (30) days of the date the KYEIS emission survey is mailed to the permittee.

11. Results of performance test(s) required by the permit shall be submitted to the Division by the source or its representative within forty-five days or sooner if required by an applicable standard, after the completion of the fieldwork.

SECTION G - GENERAL PROVISIONS

(a) General Compliance Requirements

1. The permittee shall comply with all conditions of this permit. Noncompliance shall be a violation of 401 KAR 52:020 and of the Clean Air Act and is grounds for enforcement action including but not limited to termination, revocation and reissuance, revision or denial of a permit [Section 1a, 3 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020 Section 26].

2. The filing of a request by the permittee for any permit revision, revocation, reissuance, or termination, or of a notification of a planned change or anticipated noncompliance, shall not stay any permit condition [Section 1a, 6 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

3. This permit may be revised, revoked, reopened and reissued, or terminated for cause in accordance with 401 KAR 52:020, Section 19. The permit will be reopened for cause and revised accordingly under the following circumstances:
   a. If additional requirements become applicable to the source and the remaining permit term is three (3) years or longer. In this case, the reopening shall be completed no later than eighteen (18) months after promulgation of the applicable requirement. A reopening shall not be required if compliance with the applicable requirement is not required until after the date on which the permit is due to expire, unless this permit or any of its terms and conditions have been extended pursuant to 401 KAR 52:020, Section 12;
   b. The Cabinet or the U. S. EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements;
   c. The Cabinet or the U. S. EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit;
   d. If any additional applicable requirements of the Acid Rain Program become applicable to the source.

   Proceedings to reopen and reissue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Reopenings shall be made as expeditiously as practicable. Reopenings shall not be initiated before a notice of intent to reopen is provided to the source by the Division, at least thirty (30) days in advance of the date the permit is to be reopened, except that the Division may provide a shorter time period in the case of an emergency.

4. The permittee shall furnish information upon request of the Cabinet to determine if cause exists for modifying, revoking and reissuing, or terminating the permit; or to determine compliance with the conditions of this permit [Section 1a, 7,8 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

SECTION G - GENERAL PROVISIONS (CONTINUED)

5. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such facts or corrected information to the permitting authority [401 KAR 52:020, Section 7(1)].

6. Any condition or portion of this permit which becomes suspended or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this permit [Section 1a, 14 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

7. The permittee shall not use as a defense in an enforcement action the contention that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance [Section 1a, 4 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

8. Except for requirements identified in this permit as state-origin requirements, all terms and conditions shall be enforceable by the United States Environmental Protection Agency and citizens of the United States [Section 1a, 15 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

9. This permit shall be subject to suspension if the permittee fails to pay all emissions fees within 90 days after the date of notice as specified in 401 KAR 50:038, Section 3(6) [Section 1a, 10 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

10. Nothing in this permit shall alter or affect the liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance [401 KAR 52:020, Section 11(3)(b)].

11. This permit does not convey property rights or exclusive privileges [Section 1a, 9 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

12. Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by the Kentucky Cabinet for Environmental and Public Protection or any other federal, state, or local agency.

13. Nothing in this permit shall alter or affect the authority of U.S. EPA to obtain information pursuant to Federal Statute 42 USC 7414, Inspections, monitoring, and entry [401 KAR 52:020, Section 11(3)(d)].

14. Nothing in this permit shall alter or affect the authority of U.S. EPA to impose emergency orders pursuant to Federal Statute 42 USC 7603, Emergency orders [401 KAR 52:020, Section 11(3)(a)].

SECTION G - GENERAL PROVISIONS (CONTINUED)

15. This permit consolidates the authority of any previously issued PSD, NSR, or Synthetic minor source preconstruction permit terms and conditions for various emission units and incorporates all requirements of those existing permits into one single permit for this source.

16. Pursuant to 401 KAR 52:020, Section 11, a permit shield shall not protect the owner or operator from enforcement actions for violating an applicable requirement prior to or at the time of issuance. Compliance with the conditions of a permit shall be considered compliance with:
    (a) Applicable requirements that are included and specifically identified in the permit and
    (b) Non-applicable requirements expressly identified in this permit.

17. *The permittee shall submit a startup and shut down plan to implement the requirements of this permit and 401 KAR 50:055. The plan shall be submitted at least ninety (90) days prior to the startup of the Unit #2 for the Division's approval. The startup/shutdown plan will be accessible for public review at the Division's central office and the regional office.*

18. *The permittee shall provide the Division the final design information consistent with Kentucky Open Records Act. The design plan will be accessible for public review at the Division's central office and the regional office*

(b) Permit Expiration and Reapplication Requirements

1. This permit shall remain in effect for a fixed term of five (5) years following the original date of issue. Permit expiration shall terminate the source's right to operate unless a timely and complete renewal application has been submitted to the Division at least six months prior to the expiration date of the permit. Upon a timely and complete submittal, the authorization to operate within the terms and conditions of this permit, including any permit shield, shall remain in effect beyond the expiration date, until the renewal permit is issued or denied by the Division [401 KAR 52:020, Section 12].

2. The authority to operate granted shall cease to apply if the source fails to submit additional information requested by the Division after the completeness determination has been made on any application, by whatever deadline the Division sets [401 KAR 52:020 Section 8(2)].

(c) Permit Revisions

1. A minor permit revision procedure may be used for permit revisions involving the use of economic incentive, marketable permit, emission trading, and other similar approaches, to the extent that these minor permit revision procedures are explicitly provided for in the SIP or in applicable requirements and meet the relevant requirements of 401 KAR 52:020, Section 14(2).

SECTION G - GENERAL PROVISIONS (CONTINUED)

2. This permit is not transferable by the permittee. Future owners and operators shall obtain a new permit from the Division for Air Quality. The new permit may be processed as an administrative amendment if no other change in this permit is necessary, and provided that a written agreement containing a specific date for transfer of permit responsibility coverage and liability between the current and new permittee has been submitted to the permitting authority within ten (10) days following the transfer.

(d) Construction, Start-Up, and Initial Compliance Demonstration Requirements
Pursuant to a duly submitted application the Kentucky Division for Air Quality hereby authorizes the construction of the equipment described herein, emission points 31-42 in accordance with the terms and conditions of this permit.

1. Construction of any process and/or air pollution control equipment authorized by this permit shall be conducted and completed only in compliance with the conditions of this permit.

2. Within thirty (30) days following commencement of construction and within fifteen (15) days following start-up and attainment of the maximum production rate specified in the permit application, or within fifteen (15) days following the issuance date of this permit, whichever is later, the permittee shall furnish to the Regional Office listed on the front of this permit in writing, with a copy to the Division's Frankfort Central Office, notification of the following:
   a. The date when construction commenced.
   b. The date of start-up of the affected facilities listed in this permit.
   c. The date when the maximum production rate specified in the permit application was achieved.

3. Pursuant to 401 KAR 52:020, Section 3(2), unless construction is commenced within eighteen (18) months after the permit is issued, or begins but is discontinued for a period of eighteen (18) months or is not completed within a reasonable timeframe then the construction and operating authority granted by this permit for those affected facilities for which construction was not completed shall immediately become invalid. Upon written request, the Cabinet may extend these time periods if the source shows good cause.

4. For those affected facilities for which construction is authorized by this permit, a source shall be allowed to construct with the proposed permit. Operational or final permit approval is not granted by this permit until compliance with the applicable standards specified herein has been demonstrated pursuant to 401 KAR 50:055. If compliance is not demonstrated within the prescribed timeframe provided in 401 KAR 50:055, the source shall operate thereafter only for the purpose of demonstrating compliance, unless otherwise authorized by Section I of this permit or order of the Cabinet.

SECTION G - GENERAL PROVISIONS (CONTINUED)

5. This permit shall allow time for the initial start-up, operation, and compliance demonstration of the affected facilities listed herein. However, within sixty (60) days after achieving the maximum production rate at which the affected facilities will be operated but not later than 180 days after initial start-up of such facilities, the permittee shall conduct either a performance demonstration or test as required on the affected facilities in accordance with 401 KAR 50:055, General compliance requirements. These performance tests must also be conducted in accordance with General Provisions G(d)7 of this permit and the permittee must furnish to the Division for Air Quality's Frankfort Central Office a written report of the results of such performance test

(d) Construction, Start-Up, and Initial Compliance Demonstration Requirements (continued)

6. Terms and conditions in this permit established pursuant to the construction authority of 401 KAR 51:017 or 401 KAR 51:052 shall not expire.

7. At least one month prior to the date of the required performance test, the permittee shall complete and return a Compliance Test Protocol using the current approved format, to the Division's Frankfort Central Office. Pursuant to 401 KAR 50:045, Section 5, the Division shall be notified of the actual test date at least ten (10) days prior to the test.

8. Pursuant to 401 KAR 50:045 Section 5 in order to demonstrate that a source is capable of complying with a standard at all times, a performance test shall be conducted under normal conditions that are representative of the source's operations and create the highest rate of emissions. If [When] the maximum production rate represents a source's highest emissions rate and a performance test is conducted at less than the maximum production rate, a source shall be limited to a production rate of no greater than 110 percent of the average production rate during the performance tests. If and when the facility is capable of operation at the rate specified in the application, the source may retest to demonstrate compliance at the new production rate. The Division for Air Quality may waive these requirement on a case-by-case basis if the source demonstrates to the Division's satisfaction that the source is in compliance with all applicable requirements..

(e) Acid Rain Program Requirements

1. If an applicable requirement of Federal Statute 42 USC 7401 through 7671q (the Clean Air Act) is more stringent than an applicable requirement promulgated pursuant to Federal Statute 42 USC 7651 through 7651o (Title IV of the Act), both provisions shall apply, and both shall be state and federally enforceable.

2. The source shall comply with all requirements and conditions of the Title IV, Acid Rain Permit contained in Section J of this document and the Phase II permit application (including the Phase II NO_x compliance plan, if applicable) issued for this source. The source shall also comply with all requirements of any revised or future acid rain permit(s) issued to this source.

SECTION G - GENERAL PROVISIONS (CONTINUED)

(f) Emergency Provisions

1. Pursuant to 401 KAR 52:020 Section 24(1), an emergency shall constitute an affirmative defense to an action brought for the noncompliance with the technology-based emission limitations if the permittee demonstrates through properly signed contemporaneous operating logs or relevant evidence that:
   a. An emergency occurred and the permittee can identify the cause of the emergency;
   b. The permitted facility was at the time being properly operated;
   c. During an emergency, the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards or other requirements in the permit; and
   d. Pursuant to 401 KAR 52:020, 401 KAR 50:055, and KRS 224.01-400, the permittee notified the Division as promptly as possible and submitted written notice of the emergency to the Division when emission limitations are exceeded due to an emergency. The notice shall include a description of the emergency, steps taken to mitigate emissions, and corrective actions taken.
   e. This requirement does not relieve the source from other local, state or federal notification requirements.

2. Emergency conditions listed in General Condition (f)1 above are in addition to any emergency or upset provision(s) contained in an applicable requirement [401 KAR 52:020, Section 24(3)].

3. In an enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof [401 KAR 52:020, Section 24(2)].

(g) Risk Management Provisions

1. The permittee shall comply with all applicable requirements of 401 KAR Chapter 68, Chemical Accident Prevention, which incorporates by reference 40 CFR 68, Risk Management Plan provisions. If required, the permittee shall comply with the Risk Management Program and submit a Risk Management Plan to:

   RMP Reporting Center
   P.O. Box 1515
   Lanham-Seabrook, Maryland 20703-1515

2. If requested, submit additional relevant information to the Division or the U.S. EPA.

SECTION G - GENERAL PROVISIONS (CONTINUED)

(h) Ozone depleting substances

1. The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR 82, Subpart F, except as provided for Motor Vehicle Air Conditioners (MVACs) in Subpart B:
    a. Persons opening appliances for maintenance, service, repair, or disposal shall comply with the required practices contained in 40 CFR 82.156.
    b. Equipment used during the maintenance, service, repair, or disposal of appliances shall comply with the standards for recycling and recovery equipment contained in 40 CFR 82.158.
    c. Persons performing maintenance, service, repair, or disposal of appliances shall be certified by an approved technician certification program pursuant to 40 CFR 82.161.
    d. Persons disposing of small appliances, MVACs, and MVAC-like appliances (as defined at 40 CFR 82.152) shall comply with the recordkeeping requirements pursuant to 40 CFR 82.166

(i) Ozone depleting substances continued

    e. Persons owning commercial or industrial process refrigeration equipment shall comply with the leak repair requirements pursuant to 40 CFR 82.156.
    f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant shall keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

2. If the permittee performs service on motor (fleet) vehicle air conditioners containing ozone-depleting substances, the source shall comply with all applicable requirements as specified in 40 CFR 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

SECTION H - ALTERNATE OPERATING SCENARIOS

None

SECTION I - COMPLIANCE SCHEDULE

None

SECTION J – ACID RAIN

TITLE IV PHASE II ACID RAIN

ACID RAIN PERMIT CONTENTS

1) Statement of Basis

2) SO_2 allowances allocated under this permit and NO_x requirements for each affected unit.

3) Comments, notes and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.

4) The permit application submitted for this source. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the Phase II Application and the Phase II NO_x Compliance Plan.

5) Summary of Actions

- **Statement of Basis:**

Statutory and Regulatory Authorities: In accordance with KRS 224.10-100 and Titles IV and V of the Clean Air Act, the Kentucky Natural Resources and Environmental Protection Cabinet, Division for Air Quality issues this permit pursuant to 401 KAR 52:020, Permits, 401 KAR 52:060, Acid Rain Permit, and Federal Regulation 40 CFR 76. (Unit 1 only)

SECTION J – ACID RAIN (CONTINUED)

PERMIT (Conditions)

Plant Name: Louisville Gas & Electric Company	
Affected Units: 1	

1. SO_2 Allowance Allocations and NO_x Requirements for the affected unit:

SO_2 Allowances	**Year**				
	2003	2004	2005	2006	2007
Tables 2, 3 or 4 of 40 CFR 73	9,634*	9,634*	9,634*	9,634*	9,634*

NO_x Requirements	
NO_x Limits	Pursuant to 40 CFR 76, the Kentucky Division for Air Quality approves the NO_x Early Reduction Plan for this unit. This plan is effective for calendar year 2003 through 2008. Under this NO_x compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR 75, shall not shall not exceed the applicable emission limitation, under 40 CFR 76.5, of 0.45 lb/mmBtu for tangentially fired boiler. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit is not subject to the applicable limitation, under 40 CFR 76.7 (a)(1), of 0.40 lb/mmBtu until calendar year 2008. In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions. In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only when all affected organizations have also approved this averaging plan.

* The number of allowances allocated to Phase II affected units by U. S. EPA may change under 40 CFR 73. In addition, the number of allowances actually held by an affected source in a unit may differ from the number allocated by U.S.EPA. Neither of the aforementioned condition does not necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84).

SECTION J – ACID RAIN (CONTINUED)

PERMIT (Conditions)

Plant Name: Louisville Gas and Electric Company
Affected Units: 25- 30 (TC5-TC10)

- **SO_2 Allowance Allocations and NO_x Requirements for the affected unit:**

SO_2 Allowances	**Year**				
	2003	2004	2005	2006	2007
Tables 2, 3 or 4 of 40 CFR 73	0*	0*	0*	0*	0*

NO_x Requirements	
NO_x Limits	N/A**

* For newly constructed units, there are no SO_2 allowances per USEPA Acid Rain Program

** These units currently do not have applicable NO_x limits set by 40 CFR, part 76.

SECTION J – ACID RAIN (CONTINUED)

PERMIT (Conditions)

Plant Name: Louisville Gas and Electric Company	
Affected Units: 31 (Unit 2)	

- **SO_2 Allowance Allocations and NO_x Requirements for the affected unit:**

SO_2 Allowances	**Year**				
	2005	2006	2007	2008	2009
Tables 2, 3 or 4 of 40 CFR 73	0*	0*	0*	0*	0*

NO_x Requirements	
NO_x Limits	N/A**

* For newly constructed units, there are no SO_2 allowances per USEPA Acid Rain Program

** This unit currently does not have applicable NO_x limits set by 40 CFR, part 76.

SECTION J – ACID RAIN (CONTINUED)

2. Comments, Notes, and Justifications:

1. Affected units are one (1) tangentially fired boiler and six combustion turbines, and one (1) supercritical PC boiler.

2. A revised Phase II NO_x Permit Application was received on June 12, 2001, including the existing unit.

3. All previously issued Acid Rain permits are hereby null and void

4. Nitrogen Oxide Compliance Plan for the facility remains unchanged since September 19, 1996.

5. Initial SO Compliance Plan was submitted with AR-96-007 application.

3. Permit Application: Attached

The Phase II Permit Application, and the Phase II NO_x Early Reduction Plan are part of this permit and the source must comply with the standard requirements and special provisions set forth in the Phase II Application, the revised Phase II NO_x Compliance Plan, and the revise Phase II NO_x Early Reduction Plan.

4. Summary of Actions:
Previous Actions:

1. Draft Phase II Permit (# AR-96-007) including SO_2 compliance was issued for public comments on September 19, 1996.

2. Final Phase II Permit (# AR-96-007) including SO_2 compliance plan was issued on December 19, 1996.

3. Draft Phase II Permit (# A-98-011) was advertised in the 1998 revised SO_2 allowance allocations and NO_x emissions standard for public comment on December 8, 1998.

4. Final Phase II Permit (# A-98-011) was issued with the 1998 revised SO_2 allowance allocations and NO_x emissions standards.

5. Draft Phase II Permit (# V-02-043) has been issued with the revised SO_2 allowance allocations and NO_x Early Reduction Plan. Draft permit relates to the Combustion turbines permitted in June 22, 2001.

6. Final Permit revised with the revised SO_2 allowance allocation and NO_x Early Reduction Plan.

Present Action:

1. Draft Revised Title V with Acid Rain Permit is being advertised for public comments.

SECTION K – NOx BUDGET PERMIT

1) **Statement of Basis**

Statutory and Regulatory Authorities: In accordance with KRS 224.10-100, the Kentucky Environmental and Public Protection Cabinet issues this permit pursuant to 401 KAR 52:020 Title V permits, 401 KAR 51:160, NO_x requirements for large utility and industrial boilers, and 40 CFR 97, Subpart C.

2) **NO_x Budget Permit Application, Form DEP 7007EE**

The NO_x Budget Permit application for these electrical generating units was submitted to the Division and received on May 27, 2005. Requirements contained in that application are hereby incorporated into and made part of this NO_x Budget Permit. Pursuant to 401 KAR 52:020, Section 3, the source shall operate in compliance with those requirements.

3) **Comments, notes, justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.**

Affected units are one (1) Pulverized coal-fired, dry bottom, tangentially fired boiler, six (6) 150-megawatt simple cycle natural gas fired units and one (1) Supercritical Pulverized Coal (SPC) fired boiler. Each unit has a capacity to generate 25 megawatts or more of electricity, which is offered for sale. The units use coal and natural gas as fuel source, and are authorized as base load electric generating units.

4) **Summary of Actions**

The NO_x Budget Permit is being issued as part of this revised Title V permit for this source. Public, affected state, and U.S. EPA review will follow procedures specified in 401 KAR 52:100.

Exhibit SLD-2 – Mill Creek Station Title V Operating Permit: 145-97-TV

LOUISVILLE - JEFFERSON COUNTY METRO GOVERNMENT
AIR POLLUTION CONTROL DISTRICT
TITLE V OPERATING PERMIT

Permit No.: 145-97-TV	Plant ID: 0127
Effective Date: 1 June 2003	Expiration Date: 1 June 2008
UTM Northing: 4212.0	UTM Easting: 595.6
SIC: 4911	NAICS: 221112 AFS: 00127

Permission is hereby given by the Air Pollution Control District of Jefferson County to operate equipment located at:

Louisville Gas & Electric Company
Mill Creek Generating Station
14660 Dixie Highway
Louisville KY 40272

The applicable procedures of District Regulation 2.16 regarding review by the U.S. EPA and public participation have been followed in the issuance of this permit. Based on review of the application on file with the District, permission is given to operate under the conditions stipulated herein. This permit and the authorization to operate the emission units listed shall expire on midnight on the expiration date shown above. If a renewal permit is not issued prior to the expiration date, the owner or operator may continue to operate in accordance with the terms and conditions of this permit beyond the expiration date, provided that a complete renewal application is submitted to the District no earlier than eighteen (18) months and no later than one-hundred eighty (180) days prior to the expiration date.

Permit Applicant: Louisville Gas & Electric Company

Responsible Official: John N. Voyles, Jr.

Title of Responsible Official: General Manager, Cane Run, Ohio Falls, & Combustion Turbines

Date Application Received: 21 February 1997

Date Application Administratively Complete: 18 April 1997

Date Public Notice Given: 17 December 2000; 19 January 2003

Reviewing Engineer (61) Air Pollution Control Officer

Table of Contents

Title V Permit Revisions/Changes

Revision No.	Date of Reissuance	Public Notice Date	Type	Emission Unit/Page No.	Description
Initial	06/01/2003	01/19/2003	Initial	Entire Permit	Entire Permit

Abbreviations and Acronyms

AC	- Additional Condition
AFS	- AIRS Facility Subsystem
AIRS	- Aerometric Information Retrieval System
APCD	- Air Pollution Control District
ASL	- Adjusted Significant Level
atm	- Atmosphere
BACT	- Best Available Control Technology
Btu	- British Thermal Unit
°C	- Degrees Centigrade
CEMS	- Continuous Emission Monitoring System
CAAA	- Clean Air Act Amendments (15 November 1990)
cf	- Cubic foot
DOE	- District Only Enforceable
°F	- Degrees Fahrenheit
gal	- Gallon
HAP	- Hazardous Air Pollutant
Hg	- Mercury
hr	- hour
lbs	- Pounds
l	- Liter
MACT	- Maximum Achievable Control Technology
m	- Meter
mg	- Milligram
mm	- Millimeter
MM	- Million
MOCS	- Management of Change System
NAICS	- North American Industry Classification System
NSR	- New Source Review
NO_x	- Nitrogen oxides
NSPS	- New Source Performance Standards
PM	- Particulate Matter
PM_{10}	- Particulate matter less than 10 microns
ppm	- Parts per million
PSD	- Prevention of Significant Deterioration
PMP	- Preventive Maintenance Plan
psia	- Pounds per square inch absolute
RACT	- Reasonably Available Control Technology
SIC	- Standard Industrial Classification
SIP	- State Implementation Plan
SO_2	- Sulfur dioxide
TAL	- Threshold Ambient Limit
TAP	- Toxic Air Pollutant
tpy	- Tons per year
VOC	- Volatile Organic Compound
UTM	- Universal Transverse Mercator

Preamble

Title V of the Clean Air Act Amendments of 1990 required EPA to create an operating permit program for implementation by state or local air permitting authorities. The purposes of this program are (1) to require an affected company to assume full responsibility for demonstrating compliance with applicable regulations; (2) to capture all of the regulatory information pertaining to an affected company in a single document; and (3) to make permits more consistent with each other.

A company is subject to the Title V program if it meets any of several criteria related to the nature or amount of its emissions. The Title V operating permit specifies what the affected company is, how it may operate, what its applicable regulations are, how it will demonstrate compliance, and what is required if compliance is not achieved. In Jefferson County, Kentucky, the Air Pollution Control District (APCDJC) is responsible for issuing Title V permits to affected companies and enforcing local regulations and delegated federal and state regulations. EPA may enforce federal regulations but not "District Only Enforceable Regulations".

Title V offers the public an opportunity to review and comment on a company's draft permit. It is intended to help the public understand the company's compliance responsibility under the Clean Air Act. Additionally, the Title V process provides a mechanism to incorporate new applicable requirements. Such requirements are available to the public for review and comment before they are adopted.

Title V Permit general conditions define requirements which are generally applicable to all Title V companies under the jurisdiction of APCDJC. This avoids repeating these requirements in every section of the company's Title V permit. Company-specific conditions augment the general conditions as necessary; these appear in the sections of the permit addressing individual emission units or emission points.

The general conditions include references to regulatory requirements that may not currently apply to the company, but which provide guidance for potential changes at the company or in the regulations during the life of the permit. Such requirements may become applicable if the company makes certain modifications or a new applicable requirement is adopted.

When the applicability of a section or subpart of a regulation is unclear, a clarifying citation will be made in the company's Title V permit at the emission unit/point level. Comments may also be added at the emission unit/point level to give further clarification or explanation.

The source's Title V permit may include a list of "insignificant activities," as defined in District Regulation 2.16, section 1.22 which was current as of the date the permit was proposed for review by USEPA, Region 4. Activities so identified may be insignificant with regard to application disclosure requirements but may still have generally applicable requirements that continue to apply. No periodic monitoring shall be required for facilities designated as insignificant activities.

General Conditions

1. **Compliance** - The owner or operator shall comply with all applicable requirements and with all terms and conditions of this permit. Any noncompliance shall constitute a violation of the Act, State and District regulations and shall cause the source to be subject to enforcement actions including, but not limited to, the termination, revocation and reissuance, or revision of this permit, or denial of a permit application to renew this permit. Notwithstanding any other provision in the Jefferson County portion of the Kentucky SIP approved by EPA, any credible evidence may be used for the purpose of establishing whether the owner or operator is in compliance with, has violated, or is in violation of any such plan. (Regulation 2.16, sections 4.1.3, 4.1.13.1 and 4.1.13.7)

2. **Compliance Certification** - The owner or operator shall certify, annually or more frequently if required in applicable regulations, compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. This certification shall meet the requirements of Regulation 2.16, sections 3.5.11 and 4.3.5. The owner or operator shall submit the annual compliance certification directly to the following address as well as to the District, as set forth in Regulation 2.16, section 4.3.5.4:

    US EPA - Region IV
    Air Enforcement Branch
    Atlanta Federal Center
    61 Forsyth Street
    Atlanta, GA 30303-8960

3. **Compliance Schedule** - A compliance schedule must meet the requirements of Regulation 2.16, section 3.5.9.5. The owner or operator shall submit a schedule of compliance for each emission unit that is not in compliance with all applicable requirements. A schedule of compliance shall be supplemental to, and shall not condone noncompliance with, the applicable requirements on which it is based. For each schedule of compliance, the owner or operator shall submit certified progress reports at least semi-annually, or at a more frequent period if specified in an applicable requirement or by the District in accordance with Regulation 2.16 section 4.3.4. The progress reports shall contain:

    a. Dates for achieving the activities, milestones, or compliance required in the schedule of compliance, and dates when activities, milestones, or compliance were achieved.

    b. An explanation of why dates in the schedule of compliance were not or will not be met, and preventive or corrective measures adopted.

4. **Duty to Supplement or Correct Application** - If the owner or operator fails to submit relevant facts or has submitted incorrect information in the permit application, it shall, upon discovery of the occurrence, promptly submit the supplementary facts or corrected information in accordance with Regulation 2.16, section 3.4.

5. **Emergency Provision**

   a. An emergency shall constitute an affirmative defense to an enforcement action brought for noncompliance with technology-based emission limitations. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

      i. An emergency occurred and that the owner or operator can identify the cause of the emergency.

      ii. The permitted facility was at the time being properly operated.

      iii. During the period of the emergency the owner or operator expeditiously took all reasonable steps, consistent with safe operating practices, to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

      iv. The owner or operator submitted notice meeting the requirements of Regulation 1.07 of the time when emissions limitations were exceeded because of the emergency. This notice must fulfill the requirement of this condition, and must contain a description of the emergency, any steps taken to mitigate emissions, and any corrective actions taken.

   b. In an enforcement proceeding, the owner or operator seeking to establish the occurrence of an emergency has the burden of proof.

   c. This condition is in addition to any emergency or upset provision contained in an applicable requirement. (Regulation 2.16, sections 4.7.1 through 4.7.4)

6. **Emission Fees Payment Requirements** - The owner or operator shall pay annual emission fees in accordance with Regulation 2.08. Failure to pay the emissions fees when due shall constitute a violation of District Regulations. Such failure is subject to penalties and an increase in the fee of an additional 5% per month up to a maximum of 25% of the original amount due. In addition, failure to pay emissions fees within 60 days of the due date shall automatically suspend this permit to operate until the fee is paid or a schedule for payment acceptable to the District has been established. (Regulation 2.08, section 1.3)

7. **Emission Offset Requirements** - The owner or operator shall comply with the requirements of Regulation 2.04.

8. **Enforceability Requirements** - Except for the conditions that are specifically designated as "District Only Enforceable Conditions", all terms and conditions of this permit, including any provisions designed to limit a source's potential to emit, are enforceable by EPA and citizens as specified under the Act. (Regulation 2.16, sections 4.2.1 and 4.2.2)

9. **Enforcement Action Defense**

   a. It shall not be a defense for the owner or operator in an enforcement action that it would have been necessary for the owner or operator to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

   b. The owner or operator's failure to halt or reduce activity may be a mitigating factor in assessing penalties for noncompliance if the health, safety or environmental impacts of halting or reducing operations would be more serious than the impacts of continued operation. (Regulation 2.16, sections 4.1.13.2 and 4.1.13.3)

10. **Hazardous Air Pollutants and Sources Categories** - The owner or operator shall comply with the applicable requirements of Regulations 5.02 and 5.14.

11. **Information Requests** - The owner or operator shall furnish to the District, within a reasonable time, information requested in writing by the District, to determine whether cause exists for revising, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The owner or operator shall also furnish, upon request, copies of records required to be kept by this permit. (Regulation 2.16, section 4.1.13.6) If information is submitted to the District under a claim of confidentiality, the source shall submit a copy of the confidential information directly to EPA. (Regulation 2.07, section 10.2)

12. **Insignificant Activities** - The owner or operator shall notify the District in a timely manner of any proposed change to an insignificant activity that would require a permit revision. (Regulation 2.16, Section 5)

13. **Inspection and Entry** - Upon presentation of credentials and other documents as required by law, the owner or operator shall allow the District or an authorized representative to perform the following during reasonable hours:

   a. Enter the premises to inspect any emissions-related activity or records required in this permit.

   b. Have access to and copy records required by this permit.

   c. Inspect facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required by this permit.

   d. Sample or monitor substances or parameters to assure compliance with this permit or any applicable requirements. (Regulation 2.16, section 4.3.2)

14. **Monitoring and Related Record Keeping and Reporting Requirements** - The owner or operator shall comply with the requirements of Regulation 2.16, section 4.1.9. The owner or operator shall submit all required monitoring reports at least once every six months, unless more frequent reporting is required by an applicable requirement. The reporting period shall be January 1st through June 30th and July 1st through December 31st of each

calendar year. All reports shall be postmarked by the 60th day following the end of each reporting period. If surrogate operating parameters are monitored and recorded in lieu of emission monitoring, then an exceedance of multiple parameters may be deemed a single violation by the District for enforcement purposes.

15. **Off-permit Documents** - Any applicable requirements, including emission limitations, control technology requirements, or work practice standards, contained in an off-permit document cannot be changed without undergoing the permit revision procedures in Regulation 2.16, Section 5. (Regulation 2.16, section 4.1.5)

16. **Operational Flexibility** - The owner or operator may make changes without permit revision in accordance with Regulation 2.16, section 5.8.

17. **Permit Amendments (Administrative)** - This permit can be administratively amended by the District in accordance with Regulation 2.16, sections 2.3 and 5.4.

18. **Permit Application Submittal** - The owner or operator shall submit a timely and complete application for permit renewal or significant revision. If the owner or operator submits a timely and complete application then the owner or operator's failure to have a permit is not a violation until the District takes formal action on this permit application. This protection shall cease to apply if, subsequent to completeness determination, the owner or operator fails to submit, by the deadline specified in writing by the District, additional information required to process the application as required by Regulation 2.16, sections 3 and 5.2.

19. **Permit Duration** - This permit is issued for a fixed term of 5 years, in accordance with Regulation 2.16, section 4.1.8.3.

20. **Permit Renewal, Expiration and Application** - Permit renewal, expiration and application procedural requirements shall be in accordance with Regulation 2.16, sections 4.1.8.2 and 5.3. This permit may only be renewed in accordance with section 5.3.

21. **Permit Revisions** - No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in the permit. (Regulation 2.16, section 4.1.16)

22. **Permit Revision Procedures (Minor)** - Except as provided in 40 CFR Part 72, the Acid Rain Program, this permit may be revised in accordance with Regulation 2.16, section 5.5.

23. **Permit Revision Procedures (Significant)** - A source seeking to make a significant permit revision shall meet all the Title V requirements for permit applications, issuance and renewal, in accordance with Regulation 2.16, section 5.7, and all other applicable District Regulations.

24. **Permit Revocation and Termination by the District** - The District may terminate this permit only upon written request of the owner or operator. The District may revoke a permit for cause, in accordance with Regulation 2.16, section 5.11.1.1 through 5.11.1.5. For

purposes of Section 5, substantial or unresolved noncompliance includes, but is not limited to:

a. Knowingly operating process or air pollution control equipment in a manner not allowed by an applicable requirement or that results in excess emissions of a regulated air pollutant that would endanger the public or the environment.

b. Failure or neglect to furnish information, analyses, plans, or specifications required by the District.

c. Knowingly making any false statement in any permit application.

d. Noncompliance with Regulation 1.07, section 4.2; or

e. Noncompliance with KRS Chapter 77.

25. **Permit Shield** - The permit shield shall apply in accordance with Regulation 2.16, section 4.6.1.

26. **Prevention of Significant Deterioration of Air Quality** - The owner or operator shall comply with the requirements of Regulation 2.05.

27. **Property Rights** - This permit shall not convey property rights of any sort or grant exclusive privileges in accordance with Regulation 2.16, section 4.1.13.5.

28. **Public Participation** - Except for modifications qualifying for administrative permit amendments or minor permit revision procedures, all permit proceedings shall meet the requirements of Regulations 2.07, Section 1; and 2.16, sections 5.1.1.2 and 5.5.4.

29. **Reopening For Cause** - This permit shall be reopened and revised by the District in accordance with Regulation 2.16 section 5.9.

30. **Reopening for Cause by EPA** - This permit may be revised, revoked and reissued or terminated for cause by EPA in accordance with Regulation 2.16 section 5.10.

31. **Risk Management Plan (112(r))** - For each process subject to Section 112(r) of the Act, the owner or operator shall comply with 40 CFR Part 68 and Regulation 5.15.

32. **Severability Clause** - The conditions of this permit are severable. Therefore, if any condition of this permit, or the application of any condition of this permit to any specific circumstance, is determined to be invalid, the application of the condition in question to other circumstances, as well as the remainder of this permit's conditions, shall not be affected. (Regulation 2.16, section 4.1.12)

33. **Stack Height Considerations** - The owner or operator shall comply with the requirements of Regulation 2.10.

34. **Startups, Shutdowns, and Malfunctions Requirements** - The owner or operator shall comply with the requirements of Regulation 1.07.

35. **Submittal of Reports, Data, Notifications, and Applications**

a. Applications, reports, test data, monitoring data, compliance certifications, and any other document required by this permit as set forth in Regulation 2.16 sections 3.1, 3.4, 3.5, 4.1.13.6, 5.8.5 and 5.11.7 shall be submitted to:

Air Pollution Control District of Jefferson County
850 Barret Ave
Louisville, KY 40204-1745

b. Documents which are specifically required to be submitted to EPA as set forth in Regulation 2.16 sections 3.3, and 5.8.5 shall be mailed to EPA at the following address:

US EPA - Region IV
APTMD - 12th floor
Atlanta Federal Center
61 Forsyth Street
Atlanta, GA 30303-3104

36. **Other Applicable Regulations** - The owner or operator shall comply with all applicable requirements of the following regulations:

FEDERALLY ENFORCEABLE REGULATIONS	
Regulation	**Title**
1.01	General Application of Regulations and Standards
1.02	Definitions
1.03	Abbreviations and Acronyms
1.04	Performance Tests
1.05	Compliance with Emission Standards and Maintenance Requirements
1.06	Source Self-Monitoring and Reporting
1.07	Emissions During Startups, Shutdowns, Malfunctions, and Emergencies
1.08	Administrative Procedures
1.09	Prohibition of Air Pollution
1.10	Circumvention
1.11	Control of Open Burning
1.14	Control of Fugitive Particulate Emissions
2.01	General Application
2.02	Air Pollution Regulation Requirements and Exemptions

FEDERALLY ENFORCEABLE REGULATIONS	
Regulation	**Title**
2.03	Permit Requirements - Non-Title V Construction and Operating Permits and Demolition/Renovation Permits
2.07	Public Notification for Title V, PSD, and Offset Permits; SIP Revisions; and Use of Emission Reduction Credits
2.09	Causes for Permit Suspension
2.10	Stack Height Considerations
2.11	Air Quality Model Usage
2.16	Title V Operating Permits
4.01	General Provisions for Emergency Episodes
4.02	Episode Criteria
4.03	General Abatement Requirements
4.07	Episode Reporting Requirements
5.01	General Provisions (for Hazardous Air Pollutants)
5.03	Potential Hazardous Emissions
6.01	General Provisions (for *Existing Affected Facilities*)
6.02	Emission Monitoring for Existing Sources
7.01	General Provisions (for *New Affected Facilities*)

DISTRICT ONLY ENFORCEABLE REGULATIONS	
Regulation	**Title**
1.12	Control of Nuisances
1.13	Control of Objectionable Odors in the Ambient Air
2.08	Emissions Fees, Permit Fees, Permit Renewal Procedures, and Additional Programs Fees
8.03	Commuter Vehicle Testing Requirements

37. <u>**Stratospheric Ozone Protection Requirements**</u> - Any facility having refrigeration equipment, including air conditioning equipment, which uses a Class I or II substance (listed in 40 CFR 82, Subpart A, Appendices A and B), and any facility which maintains, services, or repairs motor vehicles using a Class I or II substance as refrigerant must comply with all requirements of 40 CFR 82, Subparts A, B, and F. Those requirements include the following restrictions:

    a. Any facility having any refrigeration equipment normally containing fifty (50) pounds of refrigerant, or more, must keep servicing records documenting the date and type of all service and the quantity of any refrigerant added according to 40 CFR 82.166;

b. No person repairing or servicing a motor vehicle may perform any service on a motor vehicle air conditioner (MVAC) involving the refrigerant for such air conditioner unless the person has been properly trained and certified as provided in 40 CFR 82.34 and 40 CFR 82.40, and properly uses equipment approved according to 40 CFR 82.36 and 40 CFR 82.38, and complies with 40 CFR 82.42;

c. No person may sell or distribute, or offer for sale or distribution, any substance listed as a Class I or II substance in 40 CFR 82, Subpart A, Appendices A and B, except in compliance with 40 CFR 82.34(b), 40 CFR 82.42, and/or 40 CFR 82.166.

d. No person maintaining, servicing, repairing, or disposing of appliances may knowingly vent or otherwise release into the atmosphere any Class I or II substance used as a refrigerant in such equipment and no other person may open appliances (except MVACs as defined in 40 CFR 82.152) for service, maintenance, or repair unless the person has been properly trained and certified according to 40 CFR 82.161 and unless the person uses equipment certified for that type of appliance according to 40 CFR 82.158 and unless the person observes the practices set forth in 40 CFR 82.156 and 40 CFR 82.166;

e. No person may dispose of appliances (except small appliances, as defined in 40 CFR 82.152) without using equipment certified for that type of appliance according to 40 CFR 82.158 and without observing the practices set forth in 40 CFR 82.156 and 40 CFR 82.166;

f. No person may recover refrigerant from small appliances, MVACs and MVAC-like appliances (as defined in 40 CFR 82.152), except in compliance with the requirements of 40 CFR 82 Subpart F;

g. If the permittee manufactures, transforms, imports, or exports, a Class I or II substance (listed in 40 CFR 82, Subpart A, Appendices A and B), the permittee is subject to all requirements as specified in 40CFR82 Subpart A, Production and Consumption Controls.

(Regulation 2.16, section 4.1.5)

Emission Unit U-1 Description: Unit 1 steam generator for electric power generation

Applicable Regulations:

Federally Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
6.02	Emission Monitoring for Existing Sources	1, 2, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18
6.07	Standards of Performance for Existing Indirect Heat Exchangers	1, 2, 3, 4
6.09	Standards of Performance for Existing Process Operations	1, 2, 3, 5
6.42	Reasonably Available Control Technology Requirements for Major Volatile Organic Compound- and Nitrogen Oxides-Emitting Facilities	1, 2, 3, 4, 5
6.47	Federal Acid Rain Program for Existing Sources Incorporated by Reference	1, 2, 3, 4, 5
40 CFR Part 72	Permits Regulation	Subparts A, B, C, D, E, F, G, H, I
40 CFR Part 73	Sulfur Dioxide Allowance System	Subparts A, B, C, D, E, F, G
40 CFR Part 75	Continuous Emission Monitoring	Subparts A, B, C, D, E, F, G
40 CFR Part 76	Acid Rain Nitrogen Oxides Emission Reduction Program	76.1, 76.2, 76.3, 76.4, 76.5, 76.7, 76.8, 76.9, 76.11, 76.13, 76.14, 76.15, Appendix A, Appendix B
40 CFR Part 77	Excess Emissions	77.1, 77.2, 77.3, 77.4, 77.5, 77.6
40 CFR Part 78	Appeals Procedures for Acid Rain Program	78.1, 78.2, 78.3, 78.4, 78.5, 78.6, 78.8, 78.9, 78.10, 78.11, 78.13, 78.14, 78.15, 78.16, 78.17, 78.18, 78.19, 78.20

Allowable Emissions:

Pollutant	**Standard**
PM	See Additional Condition 1.c.
Opacity	See Additional Condition 1.d.
NO_x	See Additional Condition 1.a.
SO_2	See Additional Condition 1.b.

Components:

E-1 Tangentially fired boiler, nominal design rating of 3,085 MMBtu per hour, using pulverized coal as a primary fuel. Secondary fuel is natural gas. Control devices: C1 (Electrostatic precipitator) for PM and C2 (Flue Gas Desulfurization (FGD)) for SO_2

E-2 Coal bunker with particulate control device C3 (Dry centrifugal dust collector)

Additional Conditions

1. **Standards** (Regulation 2.16, section 4.1.1)

   a. **NO_x**

      i. For Emission Point E-1, the owner or operator shall not allow NO_x emissions to exceed 0.45 lb/MMBtu of heat input on an annual average basis. Title IV, Phase II, Acid Rain Permit (No.176-97-AR) is attached and considered part of this Title V Operating Permit. (Regulation 6.47, section 3.5 referencing 40 CFR Part 76)

      ii. For Emission Point E-1, the owner or operator shall not exceed the NO_x RACT emissions standard of 0.47 lb/MMBtu of heat input based on a rolling 30-day average. The owner or operator shall comply with the NO_x RACT Plan attached and considered part of this Title V Operating Permit. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3)

   b. **SO_2**

      i. For Emission Point E-1, the owner or operator shall not exceed 1.2 lb/MMBtu per hour heat input based on a three hour rolling average. (Regulation 6.07, section 4.1)

      ii. For Emission Point E-1, the Title IV, Phase II, Acid Rain Permit No.176-97-AR is attached and considered part of this Title V Operating Permit. (Regulation 6.47, section 3.2 referencing 40 CFR Part 73, Acid Rain Allowances are specified in Table 2)

   c. **PM**

      i. For Emission Point E-1, the owner or operator shall not exceed an allowable particulate emission rate of 0.11 lbs/MMBtu heat input based on a three hour rolling average. (Regulation 6.07, section 3.1)

      ii. For Emission Point E-2, the owner or operator shall not exceed an allowable particulate emission rate of 82.95 lbs/hr. (Regulation 6.09, section 3.2)

   d. **Opacity**

      i. For Emission Point E-1, no owner or operator shall cause the emission into the open air of particulate matter from any indirect heat exchanger which is greater than 20% opacity, except emissions into the open air of particulate matter from any indirect heat exchanger during building a new fire, cleaning the fire box, or blowing soot for a period or periods aggregating not more than ten minutes in any 60 minutes which are less than 40% opacity. (Regulation 6.07, section 3.2 and 3.3)

ii. For Emission Point E-2, the owner or operator shall not cause, suffer, allow, or permit any gases that contain particulate matter that is equal to or greater than 20% opacity. (Regulation 6.09, section 3.1)

2. **Monitoring** (Regulation 2.16, section 4.1.9.1)

a. **NO_x**

i. For Emission Point E-1, the owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement or calculation of nitrogen oxides in the flue gas. (Regulation 6.02, section 6.1.3, NO_x RACT Plan and Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(2))

ii. For Emission Point E-1, the owner or operator shall maintain and operate District approved NO_x RACT control technology in accordance with good engineering practice and the manufacturer's specifications. (Regulation 6.42, section 4.3)

iii. For Emission Point E-1, the owner or operator shall demonstrate compliance with NO_x RACT Plan limits by continuous emissions monitors (CEMs) as specified in the NO_x RACT Plan attached and incorporated into this permit. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3)

b. **SO_2**

i. For Emission Point E-1, the owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEM) for the measurement of sulfur dioxide in the flue gas. (Regulation 6.02, section 6.1.2 and Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(1))

ii. For Emission Point E-1, the owner or operator shall comply with acid rain requirements specified in 40 CFR Part 73 Table 2. (Regulation 6.47, section 3.2 referencing 40 CFR Part 73, Acid Rain Allowances are specified in Table 2)

c. **PM**

i. For Emission Point E-1, the owner or operator shall conduct annual EPA Reference Method 5 performance tests for particulate matter and monitor the ESP and wet scrubber daily as specified in Additional Condition 2.d.i.[3) and 4)].

ii. There are no monitoring requirements for emission point E-2. (See Comment 4)

d. **Opacity**

i. For Emission Point E-1:

1) The owner or operator shall determine the opacity of emissions from the stack by EPA Reference Method 9 weekly, by starting daily (Monday through Friday) at the beginning of the week to attempt to get a valid EPA Reference Method 9 test completed during that week. If the plumes are combined, an opacity reading shall be taken for informational purposes and it shall specify which plumes were combined to produce that opacity value, this combined plume reading will not count as a valid reading.

2) The owner or operator shall, using the initial PM performance test, correlate the data with opacity data obtained during the test to establish an alternate opacity trigger level. If excluding any opacity exemptions, any six minute average opacity value exceeds the trigger level, the owner or operator shall initiate an inspection of the process equipment, the control equipment and/or COM system and make any necessary repairs. If five percent or greater of the COM data (excluding exemptions) recorded in a calendar quarter show excursions above the trigger level, the owner or operator shall perform an EPA Reference Method 5 stack test in the following quarter. The District may waive this testing requirement upon demonstration that the cause(s) of the excursions have been corrected.

3) The owner or operator shall monitor daily the following for the wet scrubber:

a) Recycle Pump Amps must be > 10 Amps
b) Recycle Pump On/Off Indication must be On
c) Reaction Tank pH must be >4.0 pH
d) CEM Stack Exit Temperature must be between 100-170°F

4) The owner or operator shall monitor daily the following for the Electrostatic Precipitator (ESP):

a) Precipitator Transformer/Rectifer Availability must be ≥ 68%
b) Precipitator Secondary Kilowatts (KW) must be ≥ 2 KW

5) The owner or operator shall install, maintain, calibrate and test a continuous extractive opacity emission monitoring system in one stack at LG&E Mill Creek, Cane Run, or Trimble Co before June 30, 2004.

If the continuous extractive opacity monitoring system is approved by the District and EPA, then one stack at LG&E Mill Creek shall be equipped with the extractive opacity monitoring system by October 31, 2004. Then every 3 months thereafter (January 31, 2005, April

30, 2005, and July 31, 2005), an additional stack will be equipped with the extractive opacity monitoring system. Also, if the continuous extractive opacity monitoring system is approved by the District and EPA, then Additional Conditions 2.d.i.1) and 2.d.i.2) will be superceded by Additional Condition 2.d.i.5); Or,

If the continuous extractive opacity monitoring system is not approved, one stack at LG&E Mill Creek shall be equipped with four COMs by October 31, 2004, and then every 3 months thereafter (January 31, 2005, April 30, 2005, and July 31, 2005), an additional stack will be equipped with four COMs.

ii. For Emission Point E-2, the owner or operator shall conduct a weekly one-minute visible emissions survey, during normal operation and daylight hours, of the PM Emission Points (stacks). For Emission Points without observed visible emissions during twelve consecutive operating weeks, the owner or operator may elect to conduct a monthly one-minute visible emission survey, during normal operation and daylight hours. At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9 for stack emissions within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

3. **Record Keeping** (Regulation 2.16, section 4.1.9.2)

a. **NO_x**

i. For Emission Point E-1, the owner or operator shall keep a record identifying all deviations from the requirements of the NO_x RACT Plan.

ii. For Emission Point E-1, the owner or operator shall comply with the NO_x compliance plan requirements specified in the attached Acid Rain Permit, No.176-97-AR. These record keeping requirements shall be determined in accordance with the Title IV Phase II Acid Rain Permit and are specified in 40 CFR Part 75 Subpart F and 40 CFR Part 76 section 76.14. (Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76)

iii. For Emission Point E-1, the owner or operator shall record on an hourly basis all NO_x emission data specified in 40 CFR Part 75 section 75.50(d).

b. **SO_2**

i. For Emission Point E-1, the owner or operator shall maintain hourly records of SO_2 emissions as specified in Regulation 6.02, section 6.1.2.

ii. For Emission Point E-1, the owner or operator shall comply with the SO_2 recordkeeping requirements in the Acid Rain Permit No.176-97-AR. This permit is attached and considered part of this Title V Operating Permit. (Regulation 6.47, section 3.2 and 3.4 referencing 40 CFR Parts 73 and 75)

iii. For Emission Point E-1, the owner or operator shall record on an hourly basis all SO_2 emission data specified in 40 CFR 75.50(c).

c. **PM**

i. For Emission Point E-1, the owner or operator shall keep a record of each Method 5 test performed.

ii. For Emission Point E-2, there are no record keeping requirements for this emission point.(See Comment 3)

d. **Opacity**

i. For Emission Point E-1:

1) The owner or operator shall record every six minutes the COM output.

2) The owner or operator shall keep a record of every Method 9 test performed or the reason why it could not be performed that day and a record of every combined plume opacity reading.

3) The owner or operator shall keep a daily record of each parameter that is required to be monitored in Additional Condition 2.d.i.3) and 2.d.i.4).

4) The owner or operator shall keep a record of the output of the continuous extractive opacity monitor.

ii. For Emission Point E-2, records of the results of all visible emission surveys and tests performed shall be maintained and shall include the date and time of the survey; the name of the person conducting the survey; whether visible emissions were observed, and a description of any corrective action taken.

4. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall clearly identify all deviations from permit requirements in the quarterly reports. All reports shall be certified by a responsible official as defined in Regulation 2.16, section 2.36. If no deviations occur in that reporting period then the owner or operator shall report a negative declaration for each of the following categories. The owner or operator shall report quarterly the following:

a. **NO_x**

i. For Emission point E-1:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number,
2) The beginning and ending date of the reporting period,
3) Identification of all periods during which a deviation occurred,
4) A description, including the magnitude, of the deviation,
5) If known, the cause of the deviation, and
6) Description of any corrective action taken for each deviation.

ii. For Emission point E-1, a written report of excess emissions and the nature and cause of the excess emissions if known. The minimum data requirements for these reports are outlined in Regulation 6.02 section 16.1.

iii. For Emission point E-1, reporting requirements for the Title IV Phase II Acid Rain Permit are specified in 40 CFR Part 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G-Reporting Requirements.

b. **SO_2**

i. For Emission point E-1, a written report of excess emissions and the nature and cause of the excess emissions if known. The minimum data requirements for these reports are outlined in Regulation 6.02 Section 16. (Regulation 6.02 section 16.1)

ii. For Emission point E-1, reporting requirements for the Title IV Phase II Acid Rain Permit are specified in 40 CFR Part 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G-Reporting Requirements.

c. **PM**

i. For Emission Point E-1, the owner or operator shall submit the results of the annual Method 5 stack test within 60 days of the completion of the test.

ii. For Emission Point E-2, there are no compliance reporting requirements for this pollutant.

d. **Opacity**

i. For emission point E-1:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number,
2) The beginning and ending date of the reporting period,
3) Any Method 9 that exceeds the standard,
4) A description, including the magnitude, of the deviation,
5) If known, the cause of the deviation, and
6) Description of any corrective action taken for each deviation.

ii. For emission point E-1:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number,
2) The beginning and ending date of the reporting period,
3) Any parameter that exceeds the given ranges,
4) A description, including the magnitude, of the deviation,
5) If known, the cause of the deviation, and
6) Description of any corrective action taken for each deviation.

iii. For emission point E-1, reporting requirements for the Title IV Phase II Acid Rain Permit are specified in 40 CFR Part 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G-Reporting Requirements.

iv. For Emission Point E-2:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number
2) The beginning and ending date of the reporting period
3) The date, time and results of each exceedance of the opacity standard
4) Description of any corrective action taken for each exceedance

Comments

1. For emission point E-1, the owner or operator has exercised the Acid Rain Program early election option and is required to limit NO_x emissions from E-1 to 0.45 lb/MMBtu of heat input on an annual average basis, beginning on January 1, 1997 and continuing through December 31, 2007.

2. The NO_x RACT requirements for E-1 are met by use of Low NO_x Burners (LNB) with Overfire Air (OA). NO_x performance tests are not required under District Regulation 6.42 as CEMs are being used to demonstrate compliance.

3. For Emission Point E-2, the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 is required for this emission point.

4. Louisville Gas & Electric Company is not subject to the requirements of 40 CFR 63, Subpart Q as no chromium-based water treatment chemicals have been introduced into any cooling tower located within the plant boundaries, prior to and after the effective date of Subpart Q, in accordance with LG&E letter, dated June 23, 1998.

Emission Unit U-2 Description: Unit 2 steam generator for electric power generation

Applicable Regulations:

Federally Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
6.02	Emission Monitoring for Existing Sources	1, 2, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18
6.07	Standards of Performance for Existing Indirect Heat Exchangers	1, 2, 3, 4
6.09	Standards of Performance for Existing Process Operations	1, 2, 3, 5
6.42	Reasonably Available Control Technology Requirements for Major Volatile Organic Compound- and Nitrogen Oxides-Emitting Facilities	1, 2, 3, 4, 5
6.47	Federal Acid Rain Program for Existing Sources Incorporated by Reference	1, 2, 3, 4, 5
40 CFR Part 72	Permits Regulation	Subparts A, B, C, D, E, F, G, H, I
40 CFR Part 73	Sulfur Dioxide Allowance System	Subparts A, B, C, D, E, F, G
40 CFR Part 75	Continuous Emission Monitoring	Subparts A, B, C, D, E, F, G
40 CFR Part 76	Acid Rain Nitrogen Oxides Emission Reduction Program	76.1, 76.2, 76.3, 76.4, 76.5, 76.7, 76.8, 76.9, 76.11, 76.13, 76.14, 76.15, Appendix A, Appendix B
40 CFR Part 77	Excess Emissions	77.1, 77.2, 77.3, 77.4, 77.5, 77.6
40 CFR Part 78	Appeals Procedures for Acid Rain Program	78.1, 78.2, 78.3, 78.4, 78.5, 78.6, 78.8, 78.9, 78.10, 78.11, 78.13, 78.14, 78.15, 78.16, 78.17, 78.18, 78.19, 78.20

Allowable Emissions:

Pollutant	Standard
PM	See Additional Condition 1.c.
Opacity	See Additional Condition 1.d.
NO_x	See Additional Condition 1.a.
SO_2	See Additional Condition 1.b.

Components:

E-3 Tangentially fired boiler, nominal design rating of 3,085 MMBtu per hour, using pulverized coal as a primary fuel. Secondary fuel is natural gas. Control devices: C4 (Electrostatic precipitator) for PM and C5 (Flue Gas Desulfurization (FGD)) for SO_2

E-4 Coal bunker with particulate control device C6 (Dry centrifugal dust collector)

Additional Conditions

1. **Standards** (Regulation 2.16, section 4.1.1)

   a. **NO_x**

      i. For Emission Point E-3, the owner or operator shall not allow NO_x emissions to exceed 0.45 lb/MMBtu of heat input on an annual average basis. Title IV, Phase II, Acid Rain Permit (No.176-97-AR) is attached and considered part of this Title V Operating Permit. (Regulation 6.47, section 3.5 referencing 40 CFR Part 76)

      ii. For Emission Point E-3, the owner or operator shall not exceed the NO_x RACT emissions standard of 0.47 lb/MMBtu of heat input based on a rolling 30-day average. The owner or operator shall comply with the NO_x RACT Plan attached and considered part of this Title V Operating Permit. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3)

   b. **SO_2**

      i. For Emission Point E-3, the owner or operator shall not exceed 1.2 lb/MMBtu per hour heat input based on a three hour rolling average. (Regulation 6.07, section 4.1)

      ii. For Emission Point E-3, the Title IV, Phase II, Acid Rain Permit No.176-97-AR is attached and considered part of this Title V Operating Permit. (Regulation 6.47, section 3.2 referencing 40 CFR Part 73, Acid Rain Allowances are specified in Table 2)

   c. **PM**

      i. For Emission Point E-3, the owner or operator shall not exceed an allowable particulate emission rate of 0.11 lbs/MMBtu heat input based on a three hour rolling average. (Regulation 6.07, section 3.1)

      ii. For Emission Point E-4, the owner or operator shall not exceed an allowable particulate emission rate of 82.95 lbs/hr. (Regulation 6.09, section 3.2)

   d. **Opacity**

      i. For Emission Point E-3, no owner or operator shall cause the emission into the open air of particulate matter from any indirect heat exchanger which is greater than 20% opacity, except emissions into the open air of particulate matter from any indirect heat exchanger during building a new fire, cleaning the fire box, or blowing soot for a period or periods aggregating not more than ten minutes in any 60 minutes which are less than 40% opacity. (Regulation 6.07, section 3.2 and 3.3)

ii. For Emission Point E-4, the owner or operator shall not cause, suffer, allow, or permit any gases that contain particulate matter that is equal to or greater than 20% opacity. (Regulation 6.09, section 3.1)

2. **Monitoring** (Regulation 2.16, section 4.1.9.1)

a. **NO_x**

i. For Emission Point E-3, the owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement or calculation of nitrogen oxides in the flue gas. (Regulation 6.02, section 6.1.3, NO_x RACT Plan and Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(2))

ii. For Emission Point E-3, the owner or operator shall maintain and operate District approved NO_x RACT control technology in accordance with good engineering practice and the manufacturer's specifications. (Regulation 6.42, section 4.3)

iii. For Emission Point E-3, the owner or operator shall demonstrate compliance with NO_x RACT Plan limits by continuous emissions monitors (CEMs) as specified in the NO_x RACT Plan attached and incorporated into this permit. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3)

b. **SO_2**

i. For Emission Point E-3, the owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEM) for the measurement of sulfur dioxide in the flue gas. (Regulation 6.02, section 6.1.2 and Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(1))

ii. For Emission Point E-3, the owner or operator shall comply with acid rain requirements specified in 40 CFR Part 73 Table 2. (Regulation 6.47, section 3.2 referencing 40 CFR Part 73, Acid Rain Allowances are specified in Table 2)

c. **PM**

i. For Emission Point E-3, the owner or operator shall conduct annual EPA Reference Method 5 performance tests for particulate matter and monitor the ESP and wet scrubber daily as specified in Additional Condition 2.d.i.[3) and 4)].

ii. There are no monitoring requirements for emission point E-4. (See Comment 4)

d. **Opacity**

i. For Emission Point E-3:

1) The owner or operator shall determine the opacity of emissions from the stack by EPA Reference Method 9 weekly, by starting daily (Monday through Friday) at the beginning of the week to attempt to get a valid EPA Reference Method 9 test completed during that week. If the plumes are combined, an opacity reading shall be taken for informational purposes and it shall specify which plumes were combined to produce that opacity value, this combined plume reading will not count as a valid reading.

2) The owner or operator shall, using the initial PM performance test, correlate the data with opacity data obtained during the test to establish an alternate opacity trigger level. If excluding any opacity exemptions, any six minute average opacity value exceeds the trigger level, the owner or operator shall initiate an inspection of the process equipment, the control equipment and/or COM system and make any necessary repairs. If five percent or greater of the COM data (excluding exemptions) recorded in a calendar quarter show excursions above the trigger level, the owner or operator shall perform an EPA Reference Method 5 stack test in the following quarter. The District may waive this testing requirement upon demonstration that the cause(s) of the excursions have been corrected.

3) The owner or operator shall monitor daily the following for the wet scrubber:

a) Recycle Pump Amps must be > 10 Amps
b) Recycle Pump On/Off Indication must be On
c) Reaction Tank pH must be >4.0 pH
d) CEM Stack Exit Temperature must be between 100-170°F

4) The owner or operator shall monitor daily the following for the Electrostatic Precipitator (ESP):

a) Precipitator Transformer/Rectifer Availability must be ≥ 68%
b) Precipitator Secondary Kilowatts (KW) must be ≥ 2 KW

5) The owner or operator shall install, maintain, calibrate and test a continuous extractive opacity emission monitoring system in one stack at LG&E Mill Creek, Cane Run, or Trimble Co before June 30, 2004.

If the continuous extractive opacity monitoring system is approved by the District and EPA, then one stack at LG&E Mill Creek shall be equipped with the extractive opacity monitoring system by October

31, 2004. Then every 3 months thereafter (January 31, 2005, April 30, 2005, and July 31, 2005), an additional stack will be equipped with the extractive opacity monitoring system. Also, if the continuous extractive opacity monitoring system is approved by the District and EPA, then Additional Conditions 2.d.i.1) and 2.d.i.2) will be superceded by Additional Condition 2.d.i.5); Or,

If the continuous extractive opacity monitoring system is not approved, one stack at LG&E Mill Creek shall be equipped with four COMs by October 31, 2004, and then every 3 months thereafter (January 31, 2005, April 30, 2005, and July 31, 2005), an additional stack will be equipped with four COMs.

ii. For Emission Point E-4, the owner or operator shall conduct a weekly one-minute visible emissions survey, during normal operation and daylight hours, of the PM Emission Points (stacks). For Emission Points without observed visible emissions during twelve consecutive operating weeks, the owner or operator may elect to conduct a monthly one-minute visible emission survey, during normal operation and daylight hours. At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9 for stack emissions within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

3. **Record Keeping** (Regulation 2.16, section 4.1.9.2)

a. **NO_x**

i. For Emission Point E-3, the owner or operator shall keep a record identifying all deviations from the requirements of the NO_x RACT Plan.

ii. For Emission Point E-3, the owner or operator shall comply with the NO_x compliance plan requirements specified in the attached Acid Rain Permit, No.176-97-AR. These record keeping requirements shall be determined in accordance with the Title IV Phase II Acid Rain Permit and are specified in 40 CFR Part 75 Subpart F and 40 CFR Part 76 section 76.14. (Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76)

iii. For Emission Point E-3, the owner or operator shall record on an hourly basis all NO_x emission data specified in 40 CFR Part 75 section 75.50(d).

b. **SO_2**

i. For Emission Point E-3, the owner or operator shall maintain hourly records of SO_2 emissions as specified in Regulation 6.02, section 6.1.2.

ii. For Emission Point E-3, the owner or operator shall comply with the SO_2 recordkeeping requirements in the Acid Rain Permit No.176-97-AR. This permit is attached and considered part of this Title V Operating Permit. (Regulation 6.47, section 3.2 and 3.4 referencing 40 CFR Parts 73 and 75)

iii. For Emission Point E-3, the owner or operator shall record on an hourly basis all SO_2 emission data specified in 40 CFR 75.50(c).

c. **PM**

i. For Emission Point E-3, the owner or operator shall keep a record of each Method 5 test performed.

ii. For Emission Point E-4, there are no record keeping requirements for this emission point.(See Comment 3)

d. **Opacity**

i. For Emission Point E-3:

1) The owner or operator shall record every six minutes the COM output.

2) The owner or operator shall keep a record of every Method 9 test performed or the reason why it could not be performed that day and a record of every combined plume opacity reading.

3) The owner or operator shall keep a daily record of each parameter that is required to be monitored in Additional Condition 2.d.i.3) and 2.d.i.4).

4) The owner or operator shall keep a record of the output of the continuous extractive opacity monitor.

ii. For Emission Point E-4, records of the results of all visible emission surveys and tests performed shall be maintained and shall include the date and time of the survey; the name of the person conducting the survey; whether visible emissions were observed, and a description of any corrective action taken.

4. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall clearly identify all deviations from permit requirements in the quarterly reports. All reports shall be certified by a responsible official as defined in Regulation 2.16, section 2.36. If no deviations occur in that reporting period then the owner or operator shall report a negative declaration for each of the following categories. The owner or operator shall report quarterly the following:

a. **NO_x**

i. For Emission point E-3:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number,
2) The beginning and ending date of the reporting period,
3) Identification of all periods during which a deviation occurred,
4) A description, including the magnitude, of the deviation,
5) If known, the cause of the deviation, and
6) Description of any corrective action taken for each deviation.

ii. For Emission Point E-3, a written report of excess emissions and the nature and cause of the excess emissions if known. The minimum data requirements for these reports are outlined in Regulation 6.02 section 16.1.

iii. For Emission Point E-3, reporting requirements for the Title IV Phase II Acid Rain Permit are specified in 40 CFR Part 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G-Reporting Requirements.

b. **SO_2**

i. For Emission Point E-3, a written report of excess emissions and the nature and cause of the excess emissions if known. The minimum data requirements for these reports are outlined in Regulation 6.02 Section 16. (Regulation 6.02 section 16.1)

ii. For Emission Point E-3, reporting requirements for the Title IV Phase II Acid Rain Permit are specified in 40 CFR Part 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G-Reporting Requirements.

c. **PM**

i. For Emission Point E-3, the owner or operator shall submit the results of the annual Method 5 stack test within 60 days of the completion of the test.

ii. For Emission Point E-4, there are no compliance reporting requirements for this pollutant.

d. **Opacity**

i. For emission point E-3:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number,
2) The beginning and ending date of the reporting period,
3) Any Method 9 that exceeds the standard,
4) A description, including the magnitude, of the deviation,
5) If known, the cause of the deviation, and
6) Description of any corrective action taken for each deviation.

ii. For emission point E-3:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number,
2) The beginning and ending date of the reporting period,
3) Any parameter that exceeds the given ranges,
4) A description, including the magnitude, of the deviation,
5) If known, the cause of the deviation, and
6) Description of any corrective action taken for each deviation.

iii. For emission point E-3, reporting requirements for the Title IV Phase II Acid Rain Permit are specified in 40 CFR Part 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G-Reporting Requirements.

iv. For Emission Point E-4:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number
2) The beginning and ending date of the reporting period
3) The date, time and results of each exceedance of the opacity standard
4) Description of any corrective action taken for each exceedance

Comments

1. For emission point E-3, the owner or operator has exercised the Acid Rain Program early election option and is required to limit NO_x emissions from E-3 to 0.45 lb/MMBtu of heat input on an annual average basis, beginning on January 1, 1997 and continuing through December 31, 2007.

2. The NO_x RACT requirements for E-3 are met by use of Low NO_x Burners (LNB) with Overfire Air (OA). NO_x performance tests are not required under District Regulation 6.42 as CEMs are being used to demonstrate compliance.

3. For Emission Point E-4, the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 is required for this emission point.

4. Louisville Gas & Electric Company is not subject to the requirements of 40 CFR 63, Subpart Q as no chromium-based water treatment chemicals have been introduced into any cooling tower located within the plant boundaries, prior to and after the effective date of Subpart Q, in accordance with LG&E letter, dated June 23, 1998.

Emission Unit U-3 Description: Unit 3 steam generator for electric power generation

Applicable Regulations:

Federally Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
6.02	Emission Monitoring for Existing Sources	1, 2, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18
6.09	Standards of Performance for Existing Process Operations	1, 2, 3, 5
6.42	Reasonably Available Control Technology Requirements for Major Volatile Organic Compound- and Nitrogen Oxides-Emitting Facilities	1, 2, 3, 4, 5
6.47	Federal Acid Rain Program for Existing Sources Incorporated by Reference	1, 2, 3, 4, 5
7.06	Standards of Performance for New Indirect Heat Exchangers	1, 2, 3, 4.1.2, 4.2, 5.1.2, 6, 7, 8
40 CFR 60 Subpart A	General Provisions	60.1 through 60.19
40 CFR 60 Subpart D	Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971	60.40, 60.41, 60.42(a), 60.43, 60.44, 60.45, 60.46
40 CFR Part 72	Permits Regulation	Subparts A, B, C, D, E, F, G, H, I
40 CFR Part 73	Sulfur Dioxide Allowance System	Subparts A, B, C, D, E, F, G
40 CFR Part 75	Continuous Emission Monitoring	Subparts A, B, C, D, E, F, G
40 CFR Part 76	Acid Rain Nitrogen Oxides Emission Reduction Program	76.1, 76.2, 76.3, 76.4, 76.5, 76.7, 76.8, 76.9, 76.11, 76.13, 76.14, 76.15, Appendix A, Appendix B
40 CFR Part 77	Excess Emissions	77.1, 77.2, 77.3, 77.4, 77.5, 77.6

Federally Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
40 CFR Part 78	Appeals Procedures for Acid Rain Program	78.1, 78.2, 78.3, 78.4, 78.5, 78.6, 78.8, 78.9, 78.10, 78.11, 78.13, 78.14, 78.15, 78.16, 78.17, 78.18, 78.19, 78.20

District Enforceable Regulations		
Regulation	**Title**	**Sections**
7.02	Federal New Source Performance Standards Incorporated by Reference	1.1, 1.8, 2, 3, 4, 5

Allowable Emissions:

Pollutant	Standard
PM	See Additional Condition 1.c.
Opacity	See Additional Condition 1.d.
NO_x	See Additional Condition 1.a.
SO_2	See Additional Condition 1.b.

Components:

E-5 Dry bottom, wall-fired boiler, nominal design rating of 4,204 MMBtu per hour, using pulverized coal as a primary fuel. Secondary fuel is natural gas. Control devices: C7 (Electrostatic precipitator) for PM and C8 (Flue Gas Desulfurization (FGD)) for SO_2

E-6 Coal bunker with particulate control device C9 (Dry centrifugal dust collector)

Additional Conditions

1. **Standards** (Regulation 2.16, section 4.1.1)

   a. **NO_x**

      i. For Emission Point E-5, the owner or operator shall not allow NO_x emissions to exceed 0.50 lb/MMBtu of heat input on an annual average basis. Title IV, Phase II, Acid Rain Permit (No.176-97-AR) is attached and considered part of this Title V Operating Permit. (Regulation 6.47, section 3.5 referencing 40 CFR Part 76)

      ii. For Emission Point E-5, the owner or operator shall not exceed the NO_x RACT emissions standard of 0.52 lb/MMBtu of heat input based on a rolling 30-day average when combusting coal. The owner or operator shall comply with the NO_x RACT Plan attached and considered part of this Title V Operating Permit. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3 and Regulation 7.06, section 6 and 40 CFR 60.44(a))

      iii. For Emission Point E-5, the owner or operator shall cause to be discharged into the atmosphere any gases which contain nitrogen oxides expressed as nitrogen dioxide in excess of 0.70 lb per million BTU heat input on a 3 hour rolling average. (Regulation 7.06, section 6.1.3)

   b. **SO_2**

      i. For Emission Point E-5, the owner or operator shall not exceed 1.2 lb/MMBtu per hour heat input based on a three hour rolling average. (Regulation 7.06, section 5.1.2 and 40 CFR 60.43(a)(2))

      ii. For Emission Point E-5, the Title IV, Phase II, Acid Rain Permit No.176-97-AR is attached and considered part of this Title V Operating Permit. (Regulation 6.47, section 3.2 referencing 40 CFR Part 73, Acid Rain Allowances are specified in Table 2)

   c. **PM**

      i. For Emission Point E-5, the owner or operator shall not exceed an allowable particulate emission rate of 0.10 lbs/MMBtu heat input based on a three hour rolling average. (Regulation 7.06, section 4.1.2 and 40 CFR 60.42(a)(1))

      ii. For Emission Point E-6, the owner or operator shall not exceed an allowable particulate emission rate of 82.95 lbs/hr. (Regulation 6.09, section 3.2)

   d. **Opacity**

i. For Emission Point E-5, no owner or operator shall cause the emission into the open air of particulate matter from any indirect heat exchanger which is greater than 20% opacity, except for emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations. (Regulation 7.06, section 4.2)

ii. For Emission Point E-6, the owner or operator shall not cause, suffer, allow, or permit any gases that contain particulate matter that is equal to or greater than 20% opacity. (Regulation 7.08, section 3.1.1)

2. **Monitoring** (Regulation 2.16, section 4.1.9.1)

a. **NO_x**

i. For Emission Point E-5, the owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement or calculation of nitrogen oxides in the flue gas. (Regulation 6.02, section 6.1.3, Regulation 7.06, section 7.1, NO_x RACT Plan and Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(2))

ii. For Emission Point E-5, the owner or operator shall maintain and operate District approved NO_x RACT control technology in accordance with good engineering practice and the manufacturer's specifications. (Regulation 6.42, section 4.3)

iii. For Emission Point E-5, the owner or operator shall demonstrate compliance with NO_x RACT Plan limits by continuous emissions monitors (CEMs) as specified in the NO_x RACT Plan attached and incorporated into this permit. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3)

iv. For Emission Point E-5, the owner or operator shall monitor the NO_x emissions, the NOx allowances, and the NO_x credits as specified in Kentucky's NO_x SIP call. (See Comment 6)

b. **SO_2**

i. For Emission Point E-5, the owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEM) for the measurement of sulfur dioxide in the flue gas. (Regulation 6.02, section 6.1.2, Regulation 7.06, section 7.1 and Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(1))

ii. For Emission Point E-5, the owner or operator shall comply with acid rain requirements specified in 40 CFR Part 73 Table 2. (Regulation 6.47, section

3.2 referencing 40 CFR Part 73, Acid Rain Allowances are specified in Table 2)

c. **PM**

i. For Emission Point E-5, the owner or operator shall conduct annual EPA Reference Method 5 performance tests for particulate matter and monitor the ESP and wet scrubber daily as specified in Additional Condition 2.d.i.[3) and 4)].

ii. There are no monitoring requirements for emission point E-6. (See Comment 4)

d. **Opacity**

i. For Emission Point E-5:

1) The owner or operator shall determine the opacity of emissions from the stack by EPA Reference Method 9 weekly, by starting daily (Monday through Friday) at the beginning of the week to attempt to get a valid EPA Reference Method 9 test completed during that week. If the plumes are combined, an opacity reading shall be taken for informational purposes and it shall specify which plumes were combined to produce that opacity value, this combined plume reading will not count as a valid reading.

2) The owner or operator shall, using the initial PM performance test, correlate the data with opacity data obtained during the test to establish an alternate opacity trigger level. If excluding any opacity exemptions, any six minute average opacity value exceeds the trigger level, the owner or operator shall initiate an inspection of the process equipment, the control equipment and/or COM system and make any necessary repairs. If five percent or greater of the COM data (excluding exemptions) recorded in a calendar quarter show excursions above the trigger level, the owner or operator shall perform an EPA Reference Method 5 stack test in the following quarter. The District may waive this testing requirement upon demonstration that the cause(s) of the excursions have been corrected.

3) The owner or operator shall monitor daily the following for the wet scrubber:

a) Recycle Pump Amps must be > 10 Amps
b) Recycle Pump On/Off Indication must be On
c) Reaction Tank pH must be >4.0 pH
d) CEM Stack Exit Temperature must be between 100-220°F

4) The owner or operator shall monitor daily the following for the Electrostatic Precipitator (ESP):

a) Precipitator Transformer/Rectifer Availability must be ≥ 68%
b) Precipitator Secondary Kilowatts (KW) must be ≥ 2 KW

5) The owner or operator shall install, maintain, calibrate and test a continuous extractive opacity emission monitoring system in one stack at LG&E Mill Creek, Cane Run, or Trimble Co before June 30, 2004.

If the continuous extractive opacity monitoring system is approved by the District and EPA, then one stack at LG&E Mill Creek shall be equipped with the extractive opacity monitoring system by October 31, 2004. Then every 3 months thereafter (January 31, 2005, April 30, 2005, and July 31, 2005), an additional stack will be equipped with the extractive opacity monitoring system. Also, if the continuous extractive opacity monitoring system is approved by the District and EPA, then Additional Conditions 2.d.i.1) and 2.d.i.2) will be superceded by Additional Condition 2.d.i.5); Or,

If the continuous extractive opacity monitoring system is not approved, one stack at LG&E Mill Creek shall be equipped with four COMs by October 31, 2004, and then every 3 months thereafter (January 31, 2005, April 30, 2005, and July 31, 2005), an additional stack will be equipped with four COMs.

ii. For Emission Point E-6, the owner or operator shall conduct a weekly one-minute visible emissions survey, during normal operation and daylight hours, of the PM Emission Points (stacks). For Emission Points without observed visible emissions during twelve consecutive operating weeks, the owner or operator may elect to conduct a monthly one-minute visible emission survey, during normal operation and daylight hours. At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9 for stack emissions within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

e. **CO_2/O_2**

A CEMS for measuring either oxygen or carbon dioxide in the flue gases shall be installed, calibrated, maintained and operated by the owner or operator. The owner or operator shall use the conversion procedures specified in Regulation 7.06, sections 7.5 and 7.6. (Regulation 7.06, section 7.4)

3. **Record Keeping** (Regulation 2.16, section 4.1.9.2)

a. **NO_x**

i. For Emission Point E-5, the owner or operator shall keep a record identifying all deviations from the requirements of the NO_x RACT Plan.

ii. For Emission Point E-5, the owner or operator shall comply with the NO_x compliance plan requirements specified in the attached Acid Rain Permit, No.176-97-AR. These record keeping requirements shall be determined in accordance with the Title IV Phase II Acid Rain Permit and are specified in 40 CFR Part 75 Subpart F and 40 CFR Part 76 section 76.14. (Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76)

iii. For Emission Point E-5, the owner or operator shall record on an hourly basis all NO_x emission data specified in 40 CFR Part 75 section 75.50(d).

b. **SO_2**

i. For Emission Point E-5, the owner or operator shall maintain hourly records of SO_2 emissions as specified in Regulation 6.02, section 6.1.2.

ii. For Emission Point E-5, the owner or operator shall comply with the SO_2 recordkeeping requirements in the Acid Rain Permit No.176-97-AR. This permit is attached and considered part of this Title V Operating Permit. (Regulation 6.47, section 3.2 and 3.4 referencing 40 CFR Parts 73 and 75)

iii. For Emission Point E-5, the owner or operator shall record on an hourly basis all SO_2 emission data specified in 40 CFR 75.50(c).

c. **PM**

i. For Emission Point E-5, the owner or operator shall keep a record of each Method 5 test performed.

ii. For Emission Point E-6, there are no record keeping requirements for this emission point.(See Comment 3)

d. **Opacity**

i. For Emission Point E-5:

1) The owner or operator shall record every six minutes the COM output.

2) The owner or operator shall keep a record of every Method 9 test performed or the reason why it could not be performed that day and a record of every combined plume opacity reading.

3) The owner or operator shall keep a daily record of each parameter that is required to be monitored in Additional Condition 2.d.i.3) and 2.d.i.4).

4) The owner or operator shall keep a record of the output of the continuous extractive opacity monitor.

ii. For Emission Point E-6, records of the results of all visible emission surveys and tests performed shall be maintained and shall include the date and time of the survey; the name of the person conducting the survey; whether visible emissions were observed, and a description of any corrective action taken.

4. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall clearly identify all deviations from permit requirements in the quarterly reports. All reports shall be certified by a responsible official as defined in Regulation 2.16, section 2.36. If no deviations occur in that reporting period then the owner or operator shall report a negative declaration for each of the following categories. The owner or operator shall report quarterly the following:

a. **NO_x**

i. For Emission point E-5:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number,
2) The beginning and ending date of the reporting period,
3) Identification of all periods during which a deviation occurred,
4) A description, including the magnitude, of the deviation,
5) If known, the cause of the deviation, and
6) Description of any corrective action taken for each deviation.

ii. For Emission Point E-5, a written report of excess emissions and the nature and cause of the excess emissions if known. The minimum data requirements for these reports are outlined in Regulation 6.02 section 16.1.

iii. For Emission Point E-5, reporting requirements for the Title IV Phase II Acid Rain Permit are specified in 40 CFR Part 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G-Reporting Requirements.

iv. For Emission Point E-5, reporting requirements for the Title IV NOx Budget Emission Limitations as specified in 40 CFR Part 76.

b. **SO_2**

i. For Emission Point E-5, a written report of excess emissions and the nature and cause of the excess emissions if known. The minimum data requirements for these reports are outlined in Regulation 6.02 Section 16. (Regulation 6.02 section 16.1)

ii. For Emission Point E-5, reporting requirements for the Title IV Phase II Acid Rain Permit are specified in 40 CFR Part 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G-Reporting Requirements.

c. **PM**

i. For Emission Point E-5, the owner or operator shall submit the results of the annual Method 5 stack test within 60 days of the completion of the test.

ii. For Emission Point E-6, there are no compliance reporting requirements for this pollutant.

d. **Opacity**

i. For emission point E-5:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number,
2) The beginning and ending date of the reporting period,
3) Any Method 9 that exceeds the standard,
4) A description, including the magnitude, of the deviation,
5) If known, the cause of the deviation, and
6) Description of any corrective action taken for each deviation.

ii. For emission point E-5:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number,
2) The beginning and ending date of the reporting period,
3) Any parameter that exceeds the given ranges,
4) A description, including the magnitude, of the deviation,
5) If known, the cause of the deviation, and
6) Description of any corrective action taken for each deviation.

iii. For emission point E-5, reporting requirements for the Title IV Phase II Acid Rain Permit are specified in 40 CFR Part 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G-Reporting Requirements.

iv. For Emission Point E-6:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number
2) The beginning and ending date of the reporting period
3) The date, time and results of each exceedance of the opacity standard
4) Description of any corrective action taken for each exceedance

Comments

1. For emission point E-5, the owner or operator has exercised the Acid Rain Program early election option and is required to limit NO_x emissions from E-5 to 0.50 lb/MMBtu of heat input on an annual average basis, beginning on January 1, 1997 and continuing through December 31, 2007.

2. The NO_x RACT requirements for E-5 are met by use of Low NO_x Burners (LNB) with Overfire Air (OA). NO_x performance tests are not required under District Regulation 6.42 as CEMs are being used to demonstrate compliance.

3. For Emission Point E-6, the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 7.08 is required for this emission point.

4. Louisville Gas & Electric Company is not subject to the requirements of 40 CFR 63, Subpart Q as no chromium-based water treatment chemicals have been introduced into any cooling tower located within the plant boundaries, prior to and after the effective date of Subpart Q, in accordance with LG&E letter, dated June 23, 1998.

5. Louisville Gas & Electric Company currently has a construction permit for installing SCR on Emission Points E-5 and E-7 in order to control NO_x emissions. This construction project is not subject to Regulation 2.05, Prevention of Significant Deterioration of Air Quality since it is a control device.

6. In order to comply with the NOx reduction required by the NO_x SIP Call, the Cabinet, in consultation with EPA and public comment, has adopted the following six regulations, which became effective on August 15, 2001:

401 KAR 51:001. Definitions for 401 KAR Chapter 51

401 KAR 51:160. NO_x requirements for large utility and industrial boilers
401 KAR 51:170. NO_x requirements for cement kilns
401 KAR 51:180. NO_x credits for early reduction and emergency
401 KAR 51:190. Banking and trading of NO_x allowances
401 KAR 51:195. NO_x opt-in provisions

Emission Unit U-4 Description: Unit 4 steam generator for electric power generation

Applicable Regulations:

Federally Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
6.02	Emission Monitoring for Existing Sources	1, 2, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18
6.09	Standards of Performance for Existing Process Operations	1, 2, 3, 5
6.42	Reasonably Available Control Technology Requirements for Major Volatile Organic Compound- and Nitrogen Oxides-Emitting Facilities	1, 2, 3, 4, 5
6.47	Federal Acid Rain Program for Existing Sources Incorporated by Reference	1, 2, 3, 4, 5
7.06	Standards of Performance for New Indirect Heat Exchangers	1, 2, 3, 4.1.2, 4.2, 5.1.2, 6, 7, 8
40 CFR 60 Subpart A	General Provisions	60.1 through 60.19
40 CFR 60 Subpart D	Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971	60.40, 60.41, 60.42(a), 60.43, 60.44, 60.45, 60.46
40 CFR Part 72	Permits Regulation	Subparts A, B, C, D, E, F, G, H, I
40 CFR Part 73	Sulfur Dioxide Allowance System	Subparts A, B, C, D, E, F, G
40 CFR Part 75	Continuous Emission Monitoring	Subparts A, B, C, D, E, F, G
40 CFR Part 76	Acid Rain Nitrogen Oxides Emission Reduction Program	76.1, 76.2, 76.3, 76.4, 76.5, 76.7, 76.8, 76.9, 76.11, 76.13, 76.14, 76.15, Appendix A, Appendix B
40 CFR Part 77	Excess Emissions	77.1, 77.2, 77.3, 77.4, 77.5, 77.6

Federally Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
40 CFR Part 78	Appeals Procedures for Acid Rain Program	78.1, 78.2, 78.3, 78.4, 78.5, 78.6, 78.8, 78.9, 78.10, 78.11, 78.13, 78.14, 78.15, 78.16, 78.17, 78.18, 78.19, 78.20

District Enforceable Regulations		
Regulation	**Title**	**Sections**
7.02	Federal New Source Performance Standards Incorporated by Reference	1.1, 1.8, 2, 3, 4, 5

Allowable Emissions:

Pollutant	Standard
PM	See Additional Condition 1.c.
Opacity	See Additional Condition 1.d.
NO_x	See Additional Condition 1.a.
SO_2	See Additional Condition 1.b.

Components:

E-7 Dry bottom, wall-fired boiler, nominal design rating of 5,025 MMBtu per hour, using pulverized coal as a primary fuel. Secondary fuel is natural gas. Control devices: C10 (Electrostatic precipitator) for PM and C11 (Flue Gas Desulfurization (FGD)) for SO_2

E-8 Coal bunker with particulate control device C12 (Dry centrifugal dust collector)

Additional Conditions

1. **Standards** (Regulation 2.16, section 4.1.1)

a. **NO_x**

i. For Emission Point E-7, the owner or operator shall not allow NO_x emissions to exceed 0.50 lb/MMBtu of heat input on an annual average basis. Title IV, Phase II, Acid Rain Permit (No.176-97-AR) is attached and considered part of this Title V Operating Permit. (Regulation 6.47, section 3.5 referencing 40 CFR Part 76)

ii. For Emission Point E-7, the owner or operator shall not exceed the NO_x RACT emissions standard of 0.52 lb/MMBtu of heat input based on a rolling 30-day average when combusting coal. The owner or operator shall comply with the NO_x RACT Plan attached and considered part of this Title V Operating Permit. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3 and Regulation 7.06, section 6 and 40 CFR 60.44(a))

iii. For Emission Point E-5, the owner or operator shall cause to be discharged into the atmosphere any gases which contain nitrogen oxides expressed as nitrogen dioxide in excess of 0.70 lb per million BTU heat input on a 3 hour rolling average. (Regulation 7.06, section 6.1.3)

b. **SO_2**

i. For Emission Point E-7, the owner or operator shall not exceed 1.2 lb/MMBtu per hour heat input based on a three hour rolling average. (Regulation 7.06, section 5.1.2 and 40 CFR 60.43(a)(2))

ii. For Emission Point E-7, the Title IV, Phase II, Acid Rain Permit No.176-97-AR is attached and considered part of this Title V Operating Permit. (Regulation 6.47, section 3.2 referencing 40 CFR Part 73, Acid Rain Allowances are specified in Table 2)

c. **PM**

i. For Emission Point E-7, the owner or operator shall not exceed an allowable particulate emission rate of 0.10 lbs/MMBtu heat input based on a three hour rolling average.(Regulation 7.06, section 4.1.2 and 40 CFR 60.42(a)(1))

ii. For Emission Point E-8, the owner or operator shall not exceed an allowable particulate emission rate of 82.95 lbs/hr. (Regulation 6.09, section 3.2)

d. **Opacity**

i. For Emission Point E-7, no owner or operator shall cause the emission into the open air of particulate matter from any indirect heat exchanger which is greater than 20% opacity, except for emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations. (Regulation 7.06, section 4.2)

ii. For Emission Point E-8, the owner or operator shall not cause, suffer, allow, or permit any gases that contain particulate matter that is equal to or greater than 20% opacity. (Regulation 7.08, section 3.1.1)

2. **Monitoring** (Regulation 2.16, section 4.1.9.1)

a. **NO_x**

i. For Emission Point E-7, the owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement or calculation of nitrogen oxides in the flue gas. (Regulation 6.02, section 6.1.3, NO_x RACT Plan and Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(2))

ii. For Emission Point E-7, the owner or operator shall maintain and operate District approved NO_x RACT control technology in accordance with good engineering practice and the manufacturer's specifications. (Regulation 6.42, section 4.3)

iii. For Emission Point E-7, the owner or operator shall demonstrate compliance with NO_x RACT Plan limits by continuous emissions monitors (CEMs) as specified in the NO_x RACT Plan attached and incorporated into this permit. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3)

iv. For Emission Point E-7, the owner or operator shall demonstrate compliance with NO_x RACT Plan limits by continuous emissions monitors (CEMs) as specified in the NO_x RACT Plan attached and incorporated into this permit. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3)

v. For Emission Point E-7, the owner or operator shall monitor the NO_x emissions, the NOx allowances, and the NO_x credits as specified in Kentucky's NO_x SIP call. (See Comment 6)

b. **SO_2**

i. For Emission Point E-7, the owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEM) for the measurement of sulfur dioxide in the flue gas. (Regulation 6.02, section 6.1.2 and Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(1))

ii. For Emission Point E-7, the owner or operator shall comply with acid rain requirements specified in 40 CFR Part 73 Table 2. (Regulation 6.47, section 3.2 referencing 40 CFR Part 73, Acid Rain Allowances are specified in Table 2)

c. **PM**

i. For Emission Point E-7, the owner or operator shall conduct annual EPA Reference Method 5 performance tests for particulate matter and monitor the ESP and wet scrubber daily as specified in Additional Condition 2.d.i.[3) and 4)].

ii. There are no monitoring requirements for emission point E-8. (See Comment 4)

d. **Opacity**

i. For Emission Point E-7:

1) The owner or operator shall determine the opacity of emissions from the stack by EPA Reference Method 9 weekly, by starting daily (Monday through Friday) at the beginning of the week to attempt to get a valid EPA Reference Method 9 test completed during that week. If the plumes are combined, an opacity reading shall be taken for informational purposes and it shall specify which plumes were combined to produce that opacity value, this combined plume reading will not count as a valid reading.

2) The owner or operator shall, using the initial PM performance test, correlate the data with opacity data obtained during the test to establish an alternate opacity trigger level. If excluding any opacity exemptions, any six minute average opacity value exceeds the trigger level, the owner or operator shall initiate an inspection of the process equipment, the control equipment and/or COM system and make any necessary repairs. If five percent or greater of the COM data (excluding exemptions) recorded in a calendar quarter show excursions above the trigger level, the owner or operator shall perform an EPA Reference Method 5 stack test in the following quarter. The District may waive this testing requirement upon demonstration that the cause(s) of the excursions have been corrected.

3) The owner or operator shall monitor daily the following for the wet scrubber:

a) Recycle Pump Amps must be > 10 Amps
b) Recycle Pump On/Off Indication must be On

c) Reaction Tank pH must be >4.0 pH
d) CEM Stack Exit Temperature must be between 100-170°F

4) The owner or operator shall monitor daily the following for the Electrostatic Precipitator (ESP):

a) Precipitator Transformer/Rectifer Availability must be ≥ 68%
b) Precipitator Secondary Kilowatts (KW) must be ≥ 2 KW

5) The owner or operator shall install, maintain, calibrate and test a continuous extractive opacity emission monitoring system in one stack at LG&E Mill Creek, Cane Run, or Trimble Co before June 30, 2004.

If the continuous extractive opacity monitoring system is approved by the District and EPA, then one stack at LG&E Mill Creek shall be equipped with the extractive opacity monitoring system by October 31, 2004. Then every 3 months thereafter (January 31, 2005, April 30, 2005, and July 31, 2005), an additional stack will be equipped with the extractive opacity monitoring system. Also, if the continuous extractive opacity monitoring system is approved by the District and EPA, then Additional Conditions 2.d.i.1) and 2.d.i.2) will be superceded by Additional Condition 2.d.i.5); Or,

If the continuous extractive opacity monitoring system is not approved, one stack at LG&E Mill Creek shall be equipped with four COMs by October 31, 2004, and then every 3 months thereafter (January 31, 2005, April 30, 2005, and July 31, 2005), an additional stack will be equipped with four COMs.

ii. For Emission Point E-8, the owner or operator shall conduct a weekly one-minute visible emissions survey, during normal operation and daylight hours, of the PM Emission Points (stacks). For Emission Points without observed visible emissions during twelve consecutive operating weeks, the owner or operator may elect to conduct a monthly one-minute visible emission survey, during normal operation and daylight hours. At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9 for stack emissions within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

e. **CO_2/O_2**

A CEMS for measuring either oxygen or carbon dioxide in the flue gases shall be installed, calibrated, maintained and operated by the owner or operator. The owner or operator shall use the conversion procedures specified in Regulation 7.06, sections 7.5 and 7.6. (Regulation 7.06, section 7.4)

3. **Record Keeping** (Regulation 2.16, section 4.1.9.2)

a. **NO_x**

i. For Emission Point E-7, the owner or operator shall keep a record identifying all deviations from the requirements of the NO_x RACT Plan.

ii. For Emission Point E-7, the owner or operator shall comply with the NO_x compliance plan requirements specified in the attached Acid Rain Permit, No.176-97-AR. These record keeping requirements shall be determined in accordance with the Title IV Phase II Acid Rain Permit and are specified in 40 CFR Part 75 Subpart F and 40 CFR Part 76 section 76.14. (Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76)

iii. For Emission Point E-7, the owner or operator shall record on an hourly basis all NO_x emission data specified in 40 CFR Part 75 section 75.50(d).

b. **SO_2**

i. For Emission Point E-7, the owner or operator shall maintain hourly records of SO_2 emissions as specified in Regulation 6.02, section 6.1.2.

ii. For Emission Point E-7, the owner or operator shall comply with the SO_2 recordkeeping requirements in the Acid Rain Permit No.176-97-AR. This permit is attached and considered part of this Title V Operating Permit. (Regulation 6.47, section 3.2 and 3.4 referencing 40 CFR Parts 73 and 75)

iii. For Emission Point E-7, the owner or operator shall record on an hourly basis all SO_2 emission data specified in 40 CFR 75.50(c).

c. **PM**

i. For Emission Point E-7, the owner or operator shall keep a record of each Method 5 test performed.

ii. For Emission Point E-8, there are no record keeping requirements for this emission point.(See Comment 3)

d. **Opacity**

i. For Emission Point E-7:

1) The owner or operator shall record every six minutes the COM output.

2) The owner or operator shall keep a record of every Method 9 test performed or the reason why it could not be performed that day and a record of every combined plume opacity reading.

3) The owner or operator shall keep a daily record of each parameter that is required to be monitored in Additional Condition 2.d.i.3) and 2.d.i.4).

4) The owner or operator shall keep a record of the output of the continuous extractive opacity monitor.

ii. For Emission Point E-8, records of the results of all visible emission surveys and tests performed shall be maintained and shall include the date and time of the survey; the name of the person conducting the survey; whether visible emissions were observed, and a description of any corrective action taken.

4. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall clearly identify all deviations from permit requirements in the quarterly reports. All reports shall be certified by a responsible official as defined in Regulation 2.16, section 2.36. If no deviations occur in that reporting period then the owner or operator shall report a negative declaration for each of the following categories. The owner or operator shall report quarterly the following:

a. **NO_x**

i. For Emission point E-7:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number,
2) The beginning and ending date of the reporting period,
3) Identification of all periods during which a deviation occurred,
4) A description, including the magnitude, of the deviation,
5) If known, the cause of the deviation, and
6) Description of any corrective action taken for each deviation.

ii. For Emission Point E-7, a written report of excess emissions and the nature and cause of the excess emissions if known. The minimum data requirements for these reports are outlined in Regulation 6.02 section 16.1.

iii. For Emission Point E-7, reporting requirements for the Title IV Phase II Acid Rain Permit are specified in 40 CFR Part 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and

Retired Unit Petitions shall be submitted as specified in Subpart G-Reporting Requirements.

iv. For Emission Point E-7, reporting requirements for the Title IV NOx Budget Emission Limitations as specified in 40 CFR Part 76.

b. **SO_2**

i. For Emission Point E-7, a written report of excess emissions and the nature and cause of the excess emissions if known. The minimum data requirements for these reports are outlined in Regulation 6.02 Section 16. (Regulation 6.02 section 16.1)

ii. For Emission Point E-7, reporting requirements for the Title IV Phase II Acid Rain Permit are specified in 40 CFR Part 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G-Reporting Requirements.

c. **PM**

i. For Emission Point E-7, the owner or operator shall submit the results of the annual Method 5 stack test within 60 days of the completion of the test.

ii. For Emission Point E-8, there are no compliance reporting requirements for this pollutant.

d. **Opacity**

i. For emission point E-7:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number,
2) The beginning and ending date of the reporting period,
3) Any Method 9 that exceeds the standard,
4) A description, including the magnitude, of the deviation,
5) If known, the cause of the deviation, and
6) Description of any corrective action taken for each deviation.

ii. For emission point E-7:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number,
2) The beginning and ending date of the reporting period,
3) Any parameter that exceeds the given ranges,
4) A description, including the magnitude, of the deviation,

5) If known, the cause of the deviation, and
6) Description of any corrective action taken for each deviation.

iii. For emission point E-7, reporting requirements for the Title IV Phase II Acid Rain Permit are specified in 40 CFR Part 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G-Reporting Requirements.

iv. For Emission Point E-8:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number
2) The beginning and ending date of the reporting period
3) The date, time and results of each exceedance of the opacity standard
4) Description of any corrective action taken for each exceedance

Comments

1. For emission point E-7, the owner or operator has exercised the Acid Rain Program early election option and is required to limit NO_x emissions from E-7 to 0.50 lb/MMBtu of heat input on an annual average basis, beginning on January 1, 1997 and continuing through December 31, 2007.

2. The NO_x RACT requirements for E-7 are met by use of Low NO_x Burners (LNB) with Overfire Air (OA). NO_x performance tests are not required under District Regulation 6.42 as CEMs are being used to demonstrate compliance.

3. For Emission Point E-8, the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 7.08 is required for this emission point.

4. Louisville Gas & Electric Company is not subject to the requirements of 40 CFR 63, Subpart Q as no chromium-based water treatment chemicals have been introduced into any cooling tower located within the plant boundaries, prior to and after the effective date of Subpart Q, in accordance with LG&E letter, dated June 23, 1998.

5. Louisville Gas & Electric Company currently has a construction permit for installing SCR on Emission Points E-5 and E-7 in order to control NO_x emissions. This construction project is not subject to Regulation 2.05, Prevention of Significant Deterioration of Air Quality since it is a control device.

6. In order to comply with the NOx reduction required by the NO_x SIP Call, the Cabinet, in consultation with EPA and public comment, has adopted the following six regulations, which became effective on August 15, 2001:

401 KAR 51:001. Definitions for 401 KAR Chapter 51
401 KAR 51:160. NO_x requirements for large utility and industrial boilers
401 KAR 51:170. NO_x requirements for cement kilns
401 KAR 51:180. NO_x credits for early reduction and emergency
401 KAR 51:190. Banking and trading of NO_x allowances
401 KAR 51:195. NO_x opt-in provisions

Emission Unit U-5 and U-6 Description: Auxiliary reheat boiler for Units 3 and 4

Applicable Regulations:

Federally Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
7.06	Standards of Performance for New Indirect Heat Exchangers	1, 2, 3, 4.1.2, 4.2, 5.1.2, 6, 7, 8
40 CFR 60 Subpart A	General Provisions	60.1 through 60.19
40 CFR 60 Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	60.40c, 60.41c, 60.48c(a) and (i)

District Enforceable Regulations		
Regulation	**Title**	**Sections**
7.02	Federal New Source Performance Standards Incorporated by Reference	1.1, 1.11, 2, 3, 4, 5

Allowable Emissions:

Pollutant	Standard
NO_x	See Additional Condition 1.c.
PM	See Additional Condition 1.a.
SO_2	See Additional Condition 1.b.
Opacity	See Additional Condition 1.d.

Components:

E-10 Hot water boiler, nominal design rating of 88 MMBtu per hour, using natural gas. (U-6)

Additional Conditions

1. **Standards** (Regulation 2.16, section 4.1.1)

   a. **PM**

   For Emission Point E-10, the owner or operator shall limit the PM emissions to 0.10 lb/MMBtu heat input based on a three hour rolling average. (Regulation 7.06, section 4.1.2)

   b. **SO_2**

   For Emission Point E-10, the owner or operator shall limit SO_2 emissions to 0.8 lb/MMBtu heat input based on a three hour rolling average. (Regulation 7.06, section 5.1.2)

   c. **NO_x**

   The owner or operator shall not allow combustion of natural gas in E-10 to exceed a volume of 46.8 MM cubic feet in any calendar month in order to avoid PSD requirements.

   d. **Opacity**

   No owner or operator shall cause the emission into the open air of particulate matter from any indirect heat exchanger which is greater than 20% opacity, except for emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations. (Regulation 7.06, section 4.2)

2. **Monitoring** (Regulation 2.16, section 4.1.9.1)

   a. **PM**

   The owner or operator has shown that the PM emission standard cannot be exceeded; therefore, no additional monitoring is required to demonstrate compliance.

   b. **SO_2**

   The owner or operator has shown that the SO_2 emission standard cannot be exceeded; therefore, no additional monitoring is required to demonstrate compliance.

   c. **NO_x**

   See Additional Condition 3.c.

d. **Opacity**

The owner or operator shall conduct a monthly one-minute visible emissions survey, during normal operation and daylight hours, of the PM Emission Points (stacks). No more than four Emission Points shall be observed simultaneously. At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9 for stack emissions within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

3. **Record keeping** (Regulation 2.16, section 4.1.9.2)

a. **PM**

The owner or operator has shown that the PM emission standard cannot be exceeded; therefore, no additional recordkeeping is required to demonstrate compliance.

b. **SO_2**

The owner or operator has shown that the SO_2 emission standard cannot be exceeded; therefore, no additional recordkeeping is required to demonstrate compliance.

c. **NO_x**

The owner or operator shall maintain monthly records of the amount of fuel combusted in both of these boilers combined in order to demonstrate compliance with Additional Condition 1.c.

d. **Opacity**

The owner or operator shall keep records of all surveys and Method 9 results.

4. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall clearly identify all deviations from permit requirements in the semi-annual reports. All reports shall be certified by a responsible official as defined in Regulation 2.16, section 2.36. If no deviations occur in that reporting period then the owner or operator shall report a negative declaration for each of the following categories. The owner or operator shall report semi-annually the following:

a. **PM**

There are no compliance reporting requirements for this pollutant.

b. **SO_2**

There are no compliance reporting requirements for this pollutant.

c. **NO_x**

i. Emission Unit ID number, Stack ID number, and/or Emission point ID number
ii. The beginning and ending date of the reporting period
iii. Identification of all periods of exceedance of the combined usage limit in additional condition 1.c.
v. Description of any corrective action taken for each exceedance

d. **Opacity**

i. Emission Unit ID number, Stack ID number, and/or Emission point ID number
ii. The beginning and ending date of the reporting period
iii. The date, time and results of each Method 9 that exceeded the opacity standard
v. Description of any corrective action taken for each exceedance

Comment

1. Louisville Gas and Electric has received an exemption from the District and from EPA to keep fuel consumption records on a monthly basis rather than on a daily basis, as in 40 CFR 60.48c(g). All requirements cease when and if the units are removed from service provided that official notification has been made to the District.

2. The District has approved a Board Order dated March 21, 2001 revised February 20, 2002 (attached), which includes possibly removing these two reheat boilers. The boiler for Units 1 and 2 has been disconnected and will no longer be used.

Emission Unit U-8 Description: Gypsum Processing Plant (GPP)

Applicable Regulations:

Federally Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
7.08	Standards of Performance for New Process Operations	1, 2, 3

District Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
5.11	Standards of Performance for Existing Sources Emitting Toxic Air Pollutants	1, 2, 3, 4, 5, 6

Allowable Emissions:

Pollutant	Standard
PM	See Additional Condition 1.a.
Opacity	See Additional Condition 1.b.
TAP	See Additional Condition 1.c.

Components:

E-13 2 Flyash silos, controlled by baghouse (C15) and baghouse (C16)

Additional Conditions

1. **Standards** (Regulation 2.16, section 4.1.1)

   a. **PM**

   The owner or operator shall limit PM emissions from emission point E-13 to 34.9 lb/hr. (Regulation 7.08, section 3.3)

   b. **Opacity**

   The owner or operator shall not cause to be discharged into the atmosphere any gases that contain PM that is equal to or greater than 20% opacity. (Regulation 7.08, section 3.2)

   c. **TAP**

   The owner or operator shall not allow TAP emissions to exceed the ASL, unless RACT or modeling is performed. (Regulation 5.11)

2. **Monitoring** (Regulation 2.16, section 4.1.9.1)

   a. **PM**

   The owner or operator has shown, by worst-case calculations, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring to demonstrate compliance with the applicable PM standards specified in Regulation 7.08 is required for this emission unit.

   b. **Opacity**

   The owner or operator shall conduct a weekly one-minute visible emissions survey, during normal operation and daylight hours, of the PM Emission Points (stacks). No more than four Emission Points shall be observed simultaneously. For Emission Points without observed visible emissions during twelve consecutive operating weeks, the owner or operator may elect to conduct a monthly one-minute visible emission survey, during normal operation and daylight hours. No more than four Emission Points shall be observed simultaneously. At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9 for stack emissions within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

   c. **TAP**

See Additional Condition 3.c.

3. **Record keeping** (Regulation 2.16, section 4.1.9.2)

a. **PM**

The owner or operator has shown, by worst-case calculations, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional recordkeeping to demonstrate compliance with the applicable PM standards specified in Regulation 7.08 is required for this emission unit.

b. **Opacity**

The owner or operator shall maintain records of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date and time of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed.

c. **TAP**

The owner or operator shall calculate and record monthly TAP emissions using a 30-day material balance, and ascertain that the adjusted significant level (ASL) has not been exceeded; and make these records available to the District upon request.

4. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall clearly identify all deviations from permit requirements in the semi-annual reports. All reports shall be certified by a responsible official as defined in Regulation 2.16, section 2.36. If no deviations occur in that reporting period then the owner or operator shall report a negative declaration for each of the following categories. The owner or operator shall report semi-annually the following:

a. **PM**

There are no compliance reporting requirements for this pollutant.

b. **Opacity**

i. Emission Unit ID number and Emission point ID number
ii. The beginning and ending date of the reporting period
iii. The date, time and results of each Method 9 that exceeded the opacity standards
iv. The number of surveys that visible emissions were observed
v. Description of any corrective action taken

c. **TAP**

i. Emission Unit ID number and Emission point ID number
ii. The beginning and ending date of the reporting period
iii. Identification of all periods of exceedances of the ASL
iv. Description of any corrective action taken for each exceedance

Comment

The following equipment has been removed:

E-12 2 Lime silos, controlled by baghouse (C14)
E-14 Pug Mill Mixer A, controlled by wet dust collector (C17)
E-15 Pug Mill Mixer B, controlled by wet dust collector (C18)

Emission Unit U-9 Description: Flyash transfer bins system

Applicable Regulations:

Federally Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
7.08	Standards of Performance for New Process Operations	1, 2, 3

District Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
5.11	Standards of Performance for Existing Sources Emitting Toxic Air Pollutants	1, 2, 3, 4, 5, 6

Allowable Emissions:

Pollutant	Standard
PM	See Additional Condition 1.a.
Opacity	See Additional Condition 1.b.
TAP	See Additional Condition 1.c.

Components:

E-16 Transfer bin for units 1 and 2, controlled by baghouse (C19)
E-17 Transfer bin for unit 3, controlled by baghouse (C20)
E-18 Transfer bin for unit 4, controlled by baghouse (C21)

Additional Conditions

1. **Standards** (Regulation 2.16, section 4.1.1)

   a. **PM**

   The owner or operator shall limit PM emissions from emission point E-16 through E-18 to 34.9 lb/hr combined for all three emission points. (Regulation 7.08, section 3.3)

   b. **Opacity**

   The owner or operator shall not cause to be discharged into the atmosphere any gases that contain PM that is equal to or greater than 20% opacity. (Regulation 7.08, section 3.2)

   c. **TAP**

   The owner or operator shall not allow TAP emissions to exceed the ASL, unless BACT or modeling is performed. (Regulation 5.11)

2. **Monitoring** (Regulation 2.16, section 4.1.9.1)

   a. **PM**

   The owner or operator has shown, by worst-case calculations, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring to demonstrate compliance with the applicable PM standards specified in Regulation 7.08 is required for this emission unit.

   b. **Opacity**

   The owner or operator shall conduct a weekly one-minute visible emissions survey, during normal operation and daylight hours, of the PM Emission Points (stacks). No more than four Emission Points shall be observed simultaneously. For Emission Points without observed visible emissions during twelve consecutive operating weeks, the owner or operator may elect to conduct a monthly one-minute visible emission survey, during normal operation and daylight hours. No more than four Emission Points shall be observed simultaneously. At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9 within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

   c. **TAP**

See Additional Condition 3.c.

3. **Record keeping** (Regulation 2.16, section 4.1.9.2)

a. **PM**

The owner or operator has shown, by worst-case calculations, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional recordkeeping to demonstrate compliance with the applicable PM standards specified in Regulation 7.08 is required for this emission unit.

b. **Opacity**

The owner or operator shall maintain records of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date and time of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed.

c. **TAP**

The owner or operator shall calculate and record monthly TAP emissions using a 30-day material balance, and ascertain that the adjusted significant level (ASL) has not been exceeded; and make these records available to the District upon request.

4. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall clearly identify all deviations from permit requirements in the semi-annual reports. All reports shall be certified by a responsible official as defined in Regulation 2.16, section 2.36. If no deviations occur in that reporting period then the owner or operator shall report a negative declaration for each of the following categories. The owner or operator shall report semi-annually the following:

a. **PM**

There are no compliance reporting requirements for this pollutant.

b. **Opacity**

i. Emission Unit ID number and Emission point ID number
ii. The beginning and ending date of the reporting period
iii. The date, time and results of each Method 9 that exceeded the opacity standards
iv. The number of surveys that visible emissions were observed
v. Description of any corrective action taken

c. **TAP**

i. Emission Unit ID number and Emission point ID number
ii. The beginning and ending date of the reporting period
iii. Identification of all periods of exceedances of the ASL
iv. Description of any corrective action taken for each exceedance

Emission Unit U-10 Description: Stage I gasoline fueling station

Applicable Regulations:

Federally Enforceable Regulations		
Regulation	**Title**	**Sections**
6.40	Standards of Performance for Gasoline Transfer to Motor Vehicles (Stage II Vapor Recovery)	1.3
7.15	Standards of Performance for Gasoline Transfer to New Service Station Storage Tanks (Stage I Vapor Recovery)	1, 2, 3.1, 3.3, 3.4, 3.6, 3.7, 3.8 and 5

District Enforceable Regulations		
Regulation	**Title**	**Sections**
5.14	Hazardous Air Pollutants and Source Categories	1, 2, 3

Allowable Emissions:

Pollutant	Standards
VOC	See Additional Condition 1.

Components:

E-20 Stage I gasoline refueling station including of one 3000 gallon unleaded gasoline storage tank

Additional Conditions

1. **Standards** (Regulation 2.16, section 4.1.1)

    VOC (Regulation 7.15, section 3 and Regulation 6.40, section 1.3)

    a. The owner or operator shall install, maintain and operate the storage tank with a submerged fill pipe, vent line restrictions, a vapor balance system, and vapor tight connections on the liquid fill and vapor return hoses.

    b. The owner or operator shall not allow delivery of fuel to the storage tanks until the vapor balance system is properly connected.

    c. The owner or operator shall not allow delivery of gasoline to a service station without connecting the vapor return hose between the tank of the truck and the storage tank receiving the product.

    d. The owner or operator shall maintain all above ground tanks with dry breaks

    e. The owner or operator shall operate and maintain equipment with no defects and all fill tubes shall be equipped with vapor-tight covers including gaskets; all hoses, fittings and couplings shall be in vapor-tight condition; and all dry breaks shall have vapor tight seals and shall be equipped with vapor tight covers or dust covers.

    f. The owner or operator shall not exceed 10000 gallons of throughput per month, in order to be exempted from Regulation 6.40, except for the recordkeeping and reporting requirements. (Regulation 6.40, section 1.3)

2. **Monitoring** (Regulation 2.16, section 4.1.9.1)

    VOC

    See Additional Condition 3.

3. **Record keeping** (Regulation 2.16, section 4.1.9.2)

    VOC (Regulation 6.40, section 3.1.1)

    The owner or operator shall keep a record of the amount of throughput of gasoline per month to determine compliance with Additional Condition 1.f.

4. **Reporting** (Regulation 2.16, section 4.1.9.3)

    VOC (Regulation 6.40, section 1.3)

The owner or operator shall submit a report within 30 days of December 16 every year showing that they are still exempt from Regulation 6.40.

Emission Unit U-11 Description: Non-halogenated cold solvent parts cleaners

Applicable Regulations:

Federally Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
6.18	Standards of Performance for Solvent Metal Cleaning Equipment	1, 2, 3, 4

Allowable Emissions:

Pollutant	Standard
VOC	See Additional Condition 1.

Additional Conditions

1. **Standards** (Regulation 2.16, section 4.1.1)

VOC (Regulation 6.18, section 4.1, 4.2, 4.3.2)

a. The cleaner shall be equipped with a cover.

b. The cleaner shall be equipped with a drainage facility such that VOC that drains off parts removed from the cleaner will return to the cleaner.

c. A permanent, conspicuous label summarizing the operating requirements specified in section 4.2 shall be installed on or near the cleaner.

d. If used, the VOC spray shall be a fluid stream (not a fine, atomized, or shower type spray) at a pressure that does not cause excessive splashing.

e. Do not dispose of waste VOC or transfer it to another party in a manner that more than 20% by weight of the waste VOC can evaporate into the atmosphere. Store waste VOC only in covered containers.

f. Close degreaser cover whenever not handling a part in the cleaner.

g. Drain cleaned parts until dripping ceases (15 seconds is usually necessary).

h. The owner or operator shall not operate a cold cleaning degreaser with a solvent vapor pressure that exceeds 1.0 mm Hg (0.019 psi) measured at 20°C (68°F).

2. **Monitoring** (Regulation 2.16, section 4.1.9.1)

VOC

The owner or operator shall conduct monthly inspections to verify ongoing compliance with the control and operational requirements specified in Additional Condition 1.

3. **Record Keeping** (Regulation 2.16, section 4.1.9.2)

VOC (Regulation 6.18, section 4.4)

a. The owner or operator shall maintain records that include the following for each purchase:

i. The name and address of the solvent supplier,
ii. The date of the purchase,
iii. The type of the solvent, and

iv. The vapor pressure of the solvent measured in mm Hg at 20°C (68°F).

b. All records required by section 4.4 shall be retained for 5 years and made available to the District upon request.

c. The owner or operator shall maintain records of the results of the inspections specified in Additional Condition 2.

4. **Reporting** (Regulation 2.16, section 4.1.9.3)

VOC

There are no compliance reporting requirements for this pollutant

Emission Unit U-12 Description: Limestone Processing Operation

Applicable Regulations:

Federally Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
7.08	Standards of Performance for New Process Operations	1, 2, 3
40 CFR 60 Subpart A	General Provisions	60.1 through 60.19
40 CFR 60 Subpart OOO	Standards of Performance for Nonmetallic Mineral Processing Plants	60.670, 60.671, 60.672(b)(e), 60.673, 60.675(d), 60.676(f)(j)

District Enforceable Regulations		
Regulation	**Title**	**Applicable Sections**
7.02	Federal New Source Performance Standards Incorporated by Reference	1.1, 1.72, 2, 3, 4, 5

Allowable Emissions:

Pollutant	Standard
PM	See Additional Condition 1.a.
Opacity	See Additional Condition 1.b.

Components:

E-24 Barge Unloading including the unloading hopper at the barge (Regulation 7.08)
E-25 Transfer point from conveyor to storage pile (Regulation 7.08 and 40 CFR 60 Subpart OOO)
E-26 Transfer point from the hopper to the LA belt conveyor (Regulation 7.08 and 40 CFR 60 Subpart OOO)
E-27 Transfer point from the LA belt conveyor to the LB belt conveyor (Regulation 7.08 and 40 CFR 60 Subpart OOO)
E-28 Limestone grinding building containing the crushers and ball mills and including the reclaim conveyors (Regulation 7.08 and 40 CFR 60 Subpart OOO)

Additional Conditions

1. **Standards** (Regulation 2.16, section 4.1.1)

   a. **PM**

      i. The owner or operator shall limit PM emissions from emission point E-24 to 49.92 lb/hr. (Regulation 7.08, section 3.1.1)

      ii. The owner or operator shall limit PM emissions from emission point E-25, E-26, E-27, and E-28 to 52.28 lb/hr. (Regulation 7.08, section 3.1.1)

   b. **Opacity**

      i. For emission point E-24, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain PM that is equal to or greater than 20% opacity. (Regulation 7.08, section 3.2)

      ii. For emission point E-25, E-26, and E-27 no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any transfer point on belt conveyors or from any other affected facility any fugitive emissions which exhibit greater than 10 percent opacity. (40 CFR 60.672(b))(See Comment)

      iii. For emission point E-28, no owner or operator shall cause to be discharged into the atmosphere from any building enclosing any transfer point on a conveyor belt or any other affected facility any visible fugitive emissions. (40 CFR 60.672(e)(1))(See Comment)

2. **Monitoring** (Regulation 2.16, section 4.1.9.1)

   a. **PM**

      See Additional Condition 3.a.

   b. **Opacity**

      The owner or operator shall conduct a weekly one-minute visible emissions survey, during normal operation and daylight hours, of the PM Emission Points (E-24, E-25, E-26, E-27, and E-28). No more than four Emission Points shall be observed simultaneously. For Emission Points without observed visible emissions during twelve consecutive operating weeks, the owner or operator may elect to conduct a monthly one-minute visible emission survey, during normal operation and daylight hours. No more than four Emission Points shall be observed simultaneously. At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a

Method 9 within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

3. **Record keeping** (Regulation 2.16, section 4.1.9.2)

a. **PM**

The owner or operator shall keep a monthly records of the throughput of limestone for each emission point to determine that the PM emission limit is not exceeded.

b. **Opacity**

The owner or operator shall maintain records of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date and time of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed.

4. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall clearly identify all deviations from permit requirements in the semi-annual reports. All reports shall be certified by a responsible official as defined in Regulation 2.16, section 2.36. If no deviations occur in that reporting period then the owner or operator shall report a negative declaration for each of the following categories. The owner or operator shall report semi-annually the following:

a. **PM**

i. Emission Unit ID number and Emission point ID number
ii. The beginning and ending date of the reporting period
iii. The quantity of excess PM emissions for each exceedance
iv. Description of any corrective action taken for each exceedance

b. **Opacity**

i. Emission Unit ID number and Emission point ID number
ii. The beginning and ending date of the reporting period
iii. The date, time and results of each Method 9 that exceeded the opacity standards
iv. The number of surveys that visible emissions were observed
v. Description of any corrective action taken

Comment

By demonstrating compliance with the opacity requirements in these conditions it also demonstrates compliance with the 20% opacity requirement in Regulation 7.08.

Permit Shield

The owner or operator is hereby granted a permit shield that shall apply as long as the owner or operator demonstrates ongoing compliance with all conditions of this permit. Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements of the regulations cited in this permit as of the date of issuance, pursuant to Regulation 2.16, section 4.6.1.

Off-Permit Documents

There are no off-permit documents associated with this Title V permit.

Alternative Operating Scenario

The company requested no alternative operating scenario in its Title V application.

Insignificant Activities		
Description	**Quantity**	**Basis**
Fuel or Lubricating oils storage tanks with vapor pressure <10mm Hg @ 20 deg C	Various	Regulation 2.02, section 2.3.9.2
Storage tanks-diesel or fuel oil-not for sale, resale or distribution-annual turnover <2X capacity	Various	Regulation 2.02, section 2.3.25
Minor combustion sources <10 MMBtu/hr	Various	Regulation 2.02, section 2.1.1
Internal combustion engines	Various	Regulation 2.02, section 2.2
Brazing, soldering, or welding equipment	Various	Regulation 2.02, section 2.3.4
Emergency relief vents for boiler steam supply	Various	Regulation 2.02, section 2.3.10
Lab exhaust systems	Various	Regulation 2.02, section 2.3.11
Soil or groundwater remediation projects-passive or total removal	Various	Regulation 2.02, section 2.3.20
Portable fuel storage tanks (capacity less than 500 gallons)	Various	Regulation 2.02, section 2.3.23
No.2 fuel oil, secondary fuel (670,000 gallons each) (E-21 and E-22) (installation date 1978)	2	40 CFR60.111a(b) and Regulation 2.02, section 2.3.9.2
Ventilation system (bakeries & restaurants)	1	Regulation 2.02, section 2.3.12

Insignificant Activities		
Description	**Quantity**	**Basis**
Paved and Unpaved Roads	Various	No applicable regulation
Ashpond with wet storage	1	No applicable regulation
Infrequent evaporation of boiler cleaning solutions	Various	No applicable regulation
Infrequent burning of deminimus quantities of used oil for energy recovery	Various	No applicable regulation
Cooling Towers	Various	No applicable regulation
Enclosed sandblasting equipment	Various	No applicable regulation
Landfill	1	No applicable regulation

A. Insignificant Activities are only those activities or processes falling into the general categories defined in Regulation 2.02, Section 2, and not associated with a specific operation or process for which there is a specific regulation. Equipment associated with a specific operation or process (Emission Unit) shall be listed with the specific process even though there may be no applicable requirements. Information contained in the permit and permit summary shall clearly indicate that those items identified with negligible emissions have no applicable requirements.

B. Activities identified In Regulation 2.02, Section 2, may not require a permit and may be insignificant with regard to application disclosure requirements but may still have generally applicable requirements that continue to apply to the source and must be included in the Title V permit.

   i. No facility, having been designated as an insignificant activity, shall be exempt from any generally applicable requirements which shall include a 20% opacity limit for facilities not otherwise regulated.

   ii. No periodic monitoring shall be required for facilities designated as insignificant activities.

C. The Insignificant Activities table is correct as of the date of the permit was proposed for review by the USEPA, Region 4. The company shall submit an updated list of insignificant activities annually with the Title V compliance certification pursuant to District Regulation 2.16, section 4.3.5.3.6.

NO_x RACT Plan - Amendment 1

1. The oxides of nitrogen (NO_x, expressed as NO_2) emission from each utility boiler shall not exceed the rate as specified below, based upon a rolling 30-day average:

   Unit 1 0.47 lb/mmBtu of heat input
   Unit 2 0.47 lb/mmBtu of heat input
   Unit 3 0.52 lb/mmBtu of heat input
   Unit 4 0.52 lb/mmBtu of heat input

2. The NO_x emission rate for each utility boiler shall be determined using the methods and procedures specified in NO_x RACT Plan Appendix A - Amendment 1, except that any reference to an annual average shall be read as a rolling 30-day average.

3. The Louisville Gas and Electric Company Mill Creek Generating Station (LG&E/MCGS) shall install, maintain, and operate a NO_x continuous emissions monitoring system (CEMS) for each utility boiler and shall keep records and submit reports and other notifications as specified in NO_x RACT Plan Appendix A - Amendment 1.

4. The LG&E/MCGS shall keep a record identifying all deviations from the requirements of this NO_x RACT Plan and shall submit to the District a written report of all deviations that occurred during the preceding calendar quarter. The report shall contain the following information:
   A. The boiler number,
   B. The beginning and ending date of the reporting period,
   C. Identification of all periods during which a deviation occurred,
   D. A description, including the magnitude, of the deviation,
   E. If known, the cause of the deviation, and
   F. A description of all corrective actions taken to abate the deviation.

   If no deviation occurred during the calendar quarter, the report shall contain a negative declaration. Each report shall be submitted within 30 days following the end of the calendar quarter.

5. In lieu of the requirements in this NO_x RACT Plan, the LG&E/MCGS may comply with alternative requirements regarding emission limitations, equipment operation, test methods, monitoring, recordkeeping, or reporting, provided the following conditions are met:
   A. The alternative requirements are established and incorporated into an operating permit pursuant to a Title V Operating Permit issuance, renewal, or significant permit revision process as established in Regulation 2.16,
   B. The alternative requirements are consistent with the streamlining procedures and guidelines set forth in section II.A. of *White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program*, March 5, 1996, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. The overall effect of compliance with alternative requirements shall consider the effect on an intrinsic basis, such as pounds per million Btu of heat input. However, alternative requirements that are developed based upon revisions to the applicable requirements contained in

40 CFR Part 60 or Part 75 shall be approvable pursuant to this NO_x RACT Plan Element,

C. The U.S. Environmental Protection Agency (EPA) has not objected to the issuance, renewal, or revision of the Title V Operating Permit, and either

D. If the public comment period preceded the EPA review period, then the District had transmitted any public comments concerning the alternative requirements to EPA with the proposed permit, or

E. If the EPA and public comment periods ran concurrently, then the District had transmitted any public comments concerning the alternative requirements to EPA no later than 5 working days after the end of the public comment period.

The District's determination of approval of any alternative requirements is not binding on EPA. Noncompliance with any alternative requirement established pursuant to the Title V Operating Permit process constitutes a violation of this NO_x RACT Plan.

History: Approved 11-8-99; effective 1-1-00; amended a1/10-18-00 effective 1-1-01.

Appendix A to NO_x RACT Plan - Amendment 1
Requirements for NO_x CEMS

I. General Operating Requirements

A. Primary measurement requirements. The LG&E/MCGS shall, for each utility boiler, install, certify, operate, and maintain, in accordance with the requirements of 40 CFR 75, an oxides of nitrogen (NO_x) continuous emission monitoring system (CEMS), consisting of a NO_x pollutant concentration monitor and an oxygen (O_2) or carbon dioxide (CO_2) diluent gas monitor, with an automated data acquisition and handling system for measuring and recording NO_x concentration (in parts per million [ppm]), O_2 or CO_2 concentration (in percent O_2 or CO_2) and NO_x emission rate (in lb/mmBtu of heat input) discharged to the atmosphere. Any reference in this Appendix to an annual average shall be read as a rolling 30-day average. The LG&E/MCGS shall account for total NO_x emissions, both nitrogen oxide (NO) and nitrogen dioxide (NO_2), either by monitoring for both NO and NO_2 or by monitoring for NO only and adjusting the emissions data to account for NO_2.

B. Primary equipment performance requirements. The LG&E/MCGS shall ensure that each CEMS used to demonstrate compliance with the NO_x emission limit meets the equipment, installation, and performance specifications in 40 CFR 75 Appendix A, and is maintained according to the quality assurance and quality control procedures in 40 CFR 75 Appendix B. The NO_x emission rate for each utility boiler shall be recorded as lb/mmBtu of heat input.

C. Primary equipment hourly operating requirements.

1. The LG&E/MCGS shall ensure that all CEMS are in operation and monitoring the emissions from the associated utility boiler at all times that the utility boiler combusts any fuel except during a period of any of the following:
    a. Calibration, quality assurance, or preventive maintenance, any of which is performed pursuant to 40 CFR §75.21, 40 CFR 75 Appendix B, District regulations, District permit conditions, or this NO_x RACT Plan, or
    b. Repair, backups of data from the data acquisition and handling system, or recertification, any of which is performed pursuant to 40 CFR §75.20.
2. The LG&E/MCGS shall ensure that the following requirements are met:
    a. Each CEMS and component thereof is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute interval. The LG&E/MCGS shall reduce all volumetric flow, CO_2 concentration, O_2 concentration, NO_x concentration, and NO_x emission rate data collected by the monitors to hourly averages. Hourly averages shall be computed using at least one data point in each 15- minute quadrant of an hour during which the utility boiler combusted fuel during that quadrant of the hour. Notwithstanding this requirement, an hourly

average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of the hour) if data are unavailable as a result of the performance of any activity specified in paragraph I.C.1. of this Appendix. The LG&E/MCGS shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour.

b. Failure of a CO_2 or O_2 diluent concentration monitor, flow monitor, or NO_X pollutant concentration monitor to acquire the minimum number of data points for calculation of an hourly average shall result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour. An hourly average NO_x emission rate in lb/mmBtu of heat input is valid only if the minimum number of data points are acquired by both the pollutant concentration monitor (NO_x) and the diluent monitor (CO_2 or O_2). If a valid hour of data is not obtained, the owner or operator shall estimate and record emissions, moisture, or flow data for the missing hour by means of the automated data acquisition and handling system, in accordance with the applicable procedure for missing data substitution in 40 CFR 75 Subpart D .

D. **Optional backup monitor requirements.** If the LG&E/MCGS chooses to use two or more CEMS, each of which is capable of monitoring the same stack or duct at a specific utility boiler, then the LG&E/MCGS shall designate one CEMS as the primary monitoring system and shall record this designation in the monitoring plan. The LG&E/MCGS shall designate any other CEMS as a backup CEMS in the monitoring plan. Any other backup CEMS shall be designated as a redundant backup CEMS, non-redundant backup CEMS, or reference method CEMS, as described in 40 CFR §75.20(d). When the certified primary monitoring system is operating and not out-of-control as defined in 40 CFR §75.24, only data from the certified primary monitoring system shall be reported as valid, quality-assured data. Thus, data from a backup CEMS may be reported as valid, quality-assured data only when a backup CEMS is operating and not out-of-control as defined in 40 CFR §75.24 or in the applicable reference method in 40 CFR 60 Appendix A and when the certified primary monitoring system is not operating or is operating but out-of-control. A particular monitor may be designated both as a certified primary monitor for one unit and as a certified redundant backup monitor for another unit.

E. **Minimum measurement capability requirements.** Each CEMS and component thereof shall be capable of accurately measuring, recording, and reporting data, and shall not incur a full scale exceedance, except as provided in section 2.1.2.5 of 40 CFR 75 Appendix A.

F. The LG&E/MCGS shall not operate a utility boiler so as to discharge, or allow to be discharged, emissions of NO_x to the atmosphere without accounting for all such emissions in accordance with the methods and procedures specified in this Appendix.

G. The LG&E/MCGS shall not disrupt the CEMS, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_x emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the provisions of this Appendix.

H. The LG&E/MCGS shall not retire or permanently discontinue use of the CEMS, any component thereof, or any other approved emission monitoring system under this Appendix except under any one of the following circumstances:

1. The LG&E/MCGS is monitoring NO_x emissions from the utility boiler with another certified monitoring system approved in accordance with the provisions of paragraph I.D. of this Appendix, or
2. The LG&E/MCGS submits notification of the date of certification testing of a replacement monitoring system.

I. The quality assurance and quality control requirements in 40 CFR §75.21 that apply to NO_x pollutant concentration monitors and diluent gas monitors shall be met. A NO_x pollutant concentration monitor for determining NO_x emissions shall meet the same certification testing requirements, quality assurance requirements, and bias test requirements as those specified in 40 CFR 75 for an SO_2 pollutant concentration monitor.

J. **Moisture correction.** If a correction for the stack gas moisture content is needed to properly calculate the NO_x emission rate in lb/mmBtu of heat input (i.e., if the NO_x pollutant concentration monitor measures on a different moisture basis from the diluent monitor), LG&E/MCGS shall either report a fuel-specific default moisture value for each utility boiler operating hour, as provided in 40 CFR §75.11(b)(1), or shall install, operate, maintain, and quality assure a continuous moisture monitoring system, as defined in 40 CFR §75.11(b)(2). Notwithstanding this requirement, if Equation 19-3, 19-4 or 19-8 in Method 19 in Appendix A to 40 CFR Part 60 is used to measure NO_x emission rate, the following fuel-specific default moisture percentages shall be used in lieu of the default values specified in 40 CFR §75.11(b)(1): 5.0%, for anthracite coal; 8.0% for bituminous coal; 12.0% for sub-bituminous coal; 13.0% for lignite coal; and 15.0% for wood.

II. Specific Provisions for Monitoring NO_x Emission Rate (NO_x and diluent gas monitors)

A. The LG&E/MCGS shall meet the general operating requirements in 40 CFR §75.10 for a NO_x CEMS for each utility boiler. The diluent gas monitor in the NO_x CEMS may measure either O_2 or CO_2 concentration in the flue gases.

B. The LG&E/MCGS shall calculate hourly and rolling 30-day NO_x emission rates (in lb/mmBtu of heat input) by combining the NO_x concentration (in ppm), diluent concentration (in percent O_2 or CO_2), and percent moisture (if applicable) measurements according to the procedures in 40 CFR 75 Appendix F.

III. Monitoring plan

The LG&E/MCGS shall prepare and maintain a monitoring plan as specified in 40 CFR 75.53. The monitoring plan shall be submitted to the District no later than 45 days prior to the first scheduled certification test.

IV. Recordkeeping Provisions

A. The LG&E/MCGS shall maintain for each utility boiler a file of all measurements, data, reports, and other information required by this Appendix at the stationary source in a form suitable for inspection for at least 5 years from the date of each record. This file shall contain the following information:

1. The data and information required in paragraph IV.B. of this Appendix,
2. The component data and information used to calculate values required in paragraph IV.B. of this Appendix,
3. The current monitoring plan as specified in 40 CFR §75.53, and
4. The quality control plan as described in 40 CFR 75 Appendix B.

B. **NO_x emission record provisions.** The LG&E/MCGS shall record hourly the following information as measured and reported from the certified primary monitor, certified back-up or certified portable monitor, or other approved method of emissions determination for each utility boiler:

1. Date and hour,
2. Hourly average NO_x concentration (ppm, rounded to the nearest tenth),
3. Hourly average diluent gas concentration (percent O_2 or percent CO_2, rounded to the nearest tenth),
4. Hourly average NO_x emission rate (lb/mmBtu of heat input, rounded to nearest hundredth),
5. Hourly average NO_x emission rate (lb/mmBtu of heat input, rounded to nearest hundredth) adjusted for bias, if a bias adjustment factor is required by 40 CFR §75.24 (d),
6. Percent monitoring system data availability (recorded to the nearest tenth of a percent), calculated pursuant to 40 CFR §75.32,
7. Method of determination for hourly average NO_x emission rate using Codes 1-55 in 40 CFR §75.57 Table 4A, and
8. Unique code identifying emissions formula used to derive hourly average NO_x emission rate, as provided for in 40 CFR §75.53.

V. Certification, Quality Assurance, and Quality Control Record Provisions

A. For each NO_x pollutant concentration monitor and diluent gas monitor, the LG&E/MCGS shall record the following:

1. Results of all trial runs and certification tests and quality assurance activities and measurements (including all reference method field test sheets, charts, records of combined system responses, laboratory analyses, and example

calculations) necessary to substantiate compliance with all relevant requirements of this Appendix,

2. Bias test results as specified in 40 CFR 75, Appendix A, section 7.6.4,
3. The appropriate bias adjustment factor as follows:
    a. The value derived from Equations A-11 and A-12 in 40 CFR 75 Appendix A for any monitoring system or component that failed the bias test, or
    b. A value of 1.0 for any monitoring system or component that passed the bias test, and
4. The component/system identification code.

B. For each NO_x pollutant concentration monitor and diluent gas monitor, the LG&E/MCGS shall record the following for all daily and 7-day calibration error tests, including any follow-up tests after corrective action:

1. Instrument span and span scale,
2. Date and hour,
3. Reference value (i.e., calibration gas concentration or reference signal value, in ppm or other appropriate units),
4. Observed value (monitor response during calibration, in ppm or other appropriate units), (flag if using alternative performance specification for low emitters or differential pressure monitors),
5. Percent calibration error (rounded to the nearest tenth of a percent),
6. Calibration gas level,
7. Test number and reason for test,
8. For 7-day calibrations tests for certification or recertification, a certification from the cylinder gas vendor or CEMS vendor that calibration gases as defined in 40 CFR §72.2 and 40 CFR 75 Appendix A were used to conduct calibration error testing,
9. Description of any adjustments, corrective actions, or maintenance following a test,
10. For quality test for off-line calibration, whether the unit is off-line or on-line, and
11. The component/system identification code.

C. For each NO_x pollutant concentration monitor and diluent gas monitor, the LG&E/MCGS shall record the following for the initial and all subsequent linearity checks, including any follow-up tests after corrective action:

1. Instrument span and span scale,
2. Calibration gas level,
3. Date, hour, and minute of each gas injection at each calibration gas level,
4. Reference value (i.e., reference gas concentration for each gas injection at each calibration gas level, in ppm or other appropriate units),
5. Observed value (monitor response to each reference gas injection at each calibration gas level, in ppm or other appropriate units),
6. Mean of reference values and mean of measured values at each calibration gas level
7. Linearity error at each of the reference gases concentrations (rounded to the nearest tenth of a percent), (flag if using alternative performance specification),

8. Test number and reason for test (flag if aborted test),
9. Description of any adjustments, corrective action, or maintenance prior to a passed test or following a failed test,
10. The number of out-of-control hours, if any, following any tests, and
11. The component/system identification code.

D. For each NO_x pollutant concentration monitor and diluent gas monitor, the LG&E/MCGS shall record the following information for the initial and all subsequent relative accuracy tests and test audits:

1. Reference method(s) used,
2. Individual test run data from the relative accuracy test audit for the NOx pollutant concentration monitor or diluent gas monitor, including:
   a. Date, hour, and minute of beginning of test run,
   b. Date, hour, and minute of end of test run,
   c. Monitoring system identification code,
   d. Test number and reason for test,
   e. Operating load level (low, mid, high, or normal, as appropriate) and number of load levels comprising test,
   f. Normal load indicator for flow RATAs (except for peaking units),
   g. Units of measure,
   h. Run number,
   i. Run data from CEMS being tested, in the appropriate units of measure,
   j. Run data for reference method, in the appropriate units of measure,
   k. Flag value (0, 1, or 9, as appropriate) indicating whether run has been used in calculating relative accuracy and bias values or whether the test was aborted prior to completion,
   l. Average gross unit load (expressed as a total gross unit load rounded to the nearest MWe or as steam load rounded to the nearest thousand lb/hr), and
   m. Flag to indicate whether an alternative performance specification has been used,
3. Calculations and tabulated results, as follows:
   a. Arithmetic mean of the monitoring system measurement values, reference method values, and of their differences, as specified in Equation A-7 in 40 CFR 75 Appendix A,
   b. Standard deviation, as specified in Equation A-8 in 40 CFR 75 Appendix A,
   c. Confidence coefficient, as specified in Equation A-9 in 40 CFR 75 Appendix A,
   d. Statistical "t" value used in calculations,
   e. Relative accuracy test results, as specified in Equation A-10 in 40 CFR 75 Appendix A,
   f. Bias test results as specified in section 7.6.4 in 40 CFR 75 Appendix A,
   g. Bias adjustment factor from Equation A-12 in 40 CFR 75 Appendix A for any monitoring system or component that failed the bias test (except as otherwise provided in section 7.6.5 in 40 CFR 75 Appendix A) and 1.000 for any monitoring system or component that passed the bias test,
   h. F-factor value(s) used to convert NO_x pollutant concentration and diluent gas (O_2 or CO_2) concentration measurements into NO_x emission rates (in lb/mmBtu),
   i. The raw data and calculated results for any stratification tests performed in accordance with sections 6.5.6.1 through 6.5.6.3 in 40 CFR 75 Appendix A, and

j. For moisture monitoring systems, the coefficient "K" factor or other mathematical algorithm used to adjust the monitoring system with respect to the reference method,

4. Description of any adjustment, corrective action, or maintenance prior to a passed test or following a failed or aborted test,
5. For each run of each test using Method 7E or 3A in Appendix A of 40 CFR 60 to determine NO_x, CO_2, or O_2 concentration the following:
   a. Pollutant or diluent gas being measured,
   b. Span of reference method analyzer,
   c. Type of reference method system (e.g., extractive or dilution type),
   d. Reference method dilution factor (dilution type systems, only),
   e. Reference gas concentration (low, mid, and high gas levels) used for the 3-point, pre-test analyzer calibration error test (or, for dilution type reference method systems, for the 3-point, pre-test system calibration error test) and for any subsequent recalibrations,
   f. Analyzer responses to the zero-, mid-, and high-level calibration gases during the 3-point pre-test analyzer (or system) calibration error test and during any subsequent recalibration(s),
   g. Analyzer calibration error at each gas level (zero, mid, and high) for the 3-point, pre-test analyzer (or system) calibration error test and for any subsequent recalibration(s) (percent of span value),
   h. Upscale gas concentration (mid or high gas level) used for each pre-run or post-run system bias check or, for dilution type reference method systems, for each pre-run or post-run system calibration error check,
   i. Analyzer response to the calibration gas for each pre-run or post-run system bias (or system calibration error) check,
   j. The arithmetic average of the analyzer responses to the zero-level gas, for each pair of pre- and post-run system bias (or system calibration error) checks,
   k. The arithmetic average of the analyzer responses to the upscale calibration gas, for each pair of pre- and post-run system bias (or system calibration error) checks,
   l. The results of each pre-run and each post-run system bias (or system calibration error) check using the zero-level gas (percentage of span value),
   m. The results of each pre-run and each post-run system bias (or system calibration error) check using the upscale calibration gas (percentage of span value),
   n. Calibration drift and zero drift of analyzer during each RATA run (percentage of span value),
   o. Moisture basis of the reference method analysis,
   p. Moisture content of stack gas, in percent, during each test run (if needed to convert to moisture basis of CEMS being tested),
   q. Unadjusted (raw) average pollutant or diluent gas concentration for each run,
   r. Average pollutant or diluent gas concentration for each run, corrected for calibration bias (or calibration error) and, if applicable, corrected for moisture,
   s. The F-factor used to convert reference method data to units of lb/mmBtu (if applicable)
   t. Date(s) of the latest analyzer interference test(s),

u. Results of the latest analyzer interference test(s),
v. Date of the latest NO_2 to NO conversion test (Method 7E only),
w. Results of the latest NO_2 to NO conversion test (Method 7E only), and
x. For each calibration gas cylinder used during each RATA, record the cylinder gas vendor, cylinder number, expiration date, pollutant(s) in the cylinder, and

6. The number of out-of-control hours, if any, following any tests, and
7. The component/system identification code.

VI. Notifications

A. The LG&E/MCGS or a designated representative shall submit notice to the District for the following purposes, as required by this Appendix:

1. Initial certification and recertification test notifications. Written notification shall be submitted of initial certification tests, recertification tests, and revised test dates as specified in 40 CFR §75.20 for continuous emission monitoring systems, except for testing only of the data acquisition and handling system, and
2. Notification of initial certification testing. Initial certification test notifications shall be submitted not later than 45 days prior to the first scheduled day of initial certification testing. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means at least 7 days prior to the original scheduled test date or the revised test date, whichever is earlier.

B. For retesting following a loss of certification under 40 CFR §75.20(a)(5) or for recertification under 40 CFR §75.20(b), notice of testing shall be submitted either in writing or by telephone at least 7 days prior to the first scheduled day of testing, except that in emergency situations when testing is required following an uncontrollable failure of equipment that results in lost data, notice shall be sufficient if provided within 2 business days following the date when testing is scheduled. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided by telephone or other means at least 2 business days prior to the original scheduled test date or the revised test date, whichever is earlier.

C. Notwithstanding the notice requirements of paragraph B. above, the LG&E/MCGS may elect to repeat a certification test immediately, without advance notification, whenever the LG&E/MCGS has determined during the certification testing that a test was failed or that a second test is necessary in order to attain a reduced relative accuracy test frequency.

D. Written notice shall be submitted, either by mail or facsimile, of the date of periodic relative accuracy testing performed under 40 CFR Part 75 Appendix B no later than 21 days prior to the first scheduled day of testing. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means acceptable to the District, and the notice is provided as soon as practicable after the new testing date is known, but no later than 24 hours in advance of the new date of testing.

E. Notwithstanding the notice requirements under paragraph D. above, the LG&E/MCGS may elect to repeat a periodic relative accuracy test immediately, without additional notification whenever the LG&E/MCGS has determined that a test was failed, or that a second test is necessary in order to attain a reduced relative accuracy test frequency. If an observer from the District is present when a test is rescheduled, the observer may waive all notification requirements under paragraph D. above for the rescheduled test.

VII. Quarterly reports

A. The LG&E/MCGS shall, within 30 days following the end of each calendar quarter, submit a report to the District that includes the following data and information for each utility boiler:

1. The information and hourly data required in this Appendix, including all emissions and quality assurance data, and
2. Average NO_x emission rate (lb/mmBtu of heat input, rounded to the nearest hundredth) during the rolling 30-day averaging periods.

B. The LG&E/MCGS shall submit a certification in support of each quarterly emissions monitoring report. This certification shall indicate whether the monitoring data submitted were recorded in accordance with the requirements of this Appendix. In the event of any missing data periods, this certification shall include a description of the measures taken to minimize or eliminate the causes for the missing data periods.

Revised Board Order Dated February 20, 2002

1. LG&E shall continue to convert all four units of the Mill Creek Generating Station (Station) to wet stack operation as required by the March 21, 2001, Board Order, except that the following completion dates shall apply in lieu of the dates set forth in paragraph 2 of the March 21, 2001, Order:

Milestone	Completion Date
Unit 2 conversion	Completed
Unit 4 conversion	Completed
Unit 3 conversion (phase 1)	May 31, 2002
Unit 1 conversion	February 28, 2003
Unit 3 conversion (phase 2)	May 31, 2004

2. To address the safety concerns identified from the completed conversions, the Unit 3 conversion will be divided into two phases. In Phase 1, LG&E shall line the stack with a high-grade stainless steel alloy, install a new lined stack bottom, install water collection devices and a drain system in the upper portion of the stack, weld bypass dampers to a closed position, and install new mist eliminators and wash system. In Phase 2, LG&E shall remove the stack plume reheater and install water collection devices and a drain system in the lower portion of the stack. LG&E shall continue to operate the Unit 3 stack plume reheater until its removal in Phase 2 of the Unit 3 conversion.

3. LG&E shall monitor and review the six-minute average opacity values and the flue gas hourly temperature values in the stack to determine if there has been a degradation of the reheater efficiency. If there appears to be a decrease in the reheater efficiency, an inspection of the reheater shall be performed expeditiously to determine the problem.

4. The protection from enforcement actions, notices of violation, civil penalties, and other legal actions extended to LG&E pursuant to paragraph 5 of the March 21, 2001 Board Order shall terminate upon completion of the Unit 1 conversion or by February 28, 2003, whichever is sooner.

5. This amended Board Order shall not be deemed or construed to be a determination by the District of a violation of any federal, state, or local statute, regulation, or ordinance for any purpose whatsoever. Nothing in this Board Order shall be construed as an admission of any violation by LG&E or a waiver of any defenses available to LG&E. By consenting to the terms of this Board Order, LG&E shall not be denied the benefit of any approved amendment or modification of applicable law or regulation. LG&E reserves the right to contest, through administrative or judicial action, all determinations of the District made pursuant to this Board Order.

6. LG&E has reviewed this Board Order and consents to all its requirements and terms. Further, LG&E agrees to pay the costs of publishing legal notice of the public hearing.

7. In the event that it becomes necessary for the District to seek a court order to enforce this Board Order, LG&E agrees to pay the filing fees and costs of any such action.

Dated this 20th day of February, 2002.

TITLE IV
PHASE II ACID RAIN PERMIT

Permit No. 176-97-AR (R2) Plant ID 0127

Effective Date December 31, 2002 Expiration Date December 31, 2007

SIC Code 4911 ORIS Code 1364

Permission is hereby given by the Air Pollution Control District of Jefferson County to operate a Phase II Acid Rain Source located at:

Louisville Gas and Electric- Mill Creek Station
14660 Dixie Highway
Louisville, KY 40272

Statutory and Regulatory Authorities: In accordance with KRS Chapter 77 and Titles IV and V of the Clean Air Act, the Air Pollution Control District of Jefferson County issues this permit pursuant to Regulations 2.16, 6.47, and 7.82.

Designated Representative **Chris Hermann**

Alternate Designated Representative **John N. Voyles, Jr.**

Date Application Received **December 13, 1995**

Reviewing Engineer (61) Air Pollution Control Officer

Acid Rain Permit Revisions/Changes

Revision No.	Date of Reissuance	Public Notice Date	Type	Emission Unit/Page No.	Description
Initial	12/17/1997	NA	Initial	Entire Permit	Entire Permit
Rev. 1	12/31/1998	NA	Significant	Entire Permit	Added language and SO_2 allowances to the tables for each unit
Rev. 2	06/01/2003	NA	Reissuance	Entire Permit	Reissuance of the permit

SO_2 Allowance Allocations and NO_x Requirements for each affected unit

<table>
<tr><th></th><th></th><th>1998</th><th>1999</th><th>2000</th><th>2001</th><th>2002-2007</th></tr>
<tr><td rowspan="2">Unit 1</td><td>SO_2 allowances, under Tables 2, 3, or 4 of 40 CFR part 73.</td><td>NA</td><td>NA</td><td>8018*</td><td>8018*</td><td>8018*</td></tr>
<tr><td>NO_x Limit</td><td colspan="5">Pursuant to 40 CFR 76.8(d)(2), the Air Pollution Control District of Jefferson County approves a NO_x early election compliance plan for Unit 1. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.5(a)(1) of 0.45 lb/MMBtu for tangentially fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable emission limitation, under 40 CFR 76.7(a)(1), of 0.40 lb/MMBtu until calendar year 2008.

In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.</td></tr>
</table>

SO_2 Allowance Allocations and NO_x Requirements for each affected unit

		1998	1999	2000	2001	2002-2007
Unit 2	SO_2 allowances, under Tables 2, 3,or 4 of 40 CFR part 73.	NA	NA	8075*	8075*	8075*
	NO_x Limit	Pursuant to 40 CFR 76.8(d)(2), the Air Pollution Control District of Jefferson County approves a NO_x early election compliance plan for Unit 2. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.5(a)(1) of 0.45 lb/MMBtu for tangentially fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable emission limitation, under 40 CFR 76.7(a)(1), of 0.40 lb/MMBtu until calendar year 2008. In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.				

SO_2 Allowance Allocations and NO_x Requirements for each affected unit

		1998	1999	2000	2001	2002-2007
Unit 3	SO_2 allowances, under Tables 2, 3,or 4 of 40 CFR part 73.	NA	NA	10888*	10888*	10888*
	NO_x Limit	Pursuant to 40 CFR 76.8(d)(2), the Air Pollution Control District of Jefferson County approves a NO_x early election compliance plan for Unit 3. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.5(a)(2) of 0.50 lb/MMBtu for dry bottom wall-fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable emission limitation, under 40 CFR 76.7(a)(2), of 0.46 lb/MMBtu until calendar year 2008. In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.				

SO_2 Allowance Allocations and NO_x Requirements for each affected unit

		1998	1999	2000	2001	2002-2007
Unit 4	SO_2 allowances, under Tables 2, 3,or 4 of 40 CFR part 73.	NA	NA	13506*	13506*	13506*
	NO_x Limit	Pursuant to 40 CFR 76.8(d)(2), the Air Pollution Control District of Jefferson County approves a NO_x early election compliance plan for Unit 4. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.5(a)(2) of 0.50 lb/MMBtu for dry bottom wall-fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable emission limitation, under 40 CFR 76.7(a)(2), of 0.46 lb/MMBtu until calendar year 2008. In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.				

*The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84). The number of allowances allocated to Phase II affected units by US EPA may change under 40 CFR part 73.

Comments, Notes, and Justifications:

None

Permit Application:

The Louisville Gas & Electric Company Phase II Permit Application for the Mill Creek Generating Station, dated December 7, 1995, and signed by Chris Hermann, is attached hereto and is rendered part of this permit. The owners and operators of Louisville Gas and Electric Company must comply with the standard requirements and special provisions set forth in the application.

NO_x Compliance Plan:

The Louisville Gas & Electric Company Phase II NO_x Compliance Plan, dated December 22, 1997 and signed by John N Voyles, Jr. is attached hereto and is rendered part of this permit. The owners and operators of Louisville Gas & Electric Company must comply with the early election standard annual average NO_x emission limitation of 0.45 lb/MMBtu for Phase I tagentially fired boilers and 0.50 lb/MMBtu for Phase I dry bottom wall-fired boilers each year until calendar year 2008, unless the early election option is terminated.

Exhibit SLD-3 – Company's Letter to KYDAQ on SO_3 Mitigation

e·on | U.S.

May 12, 2006

E.ON U.S. LLC
Environmental Affairs
220 West Main Street
Louisville, Kentucky 40202
www.eon-us.com

Sharon Dodson
Director Environmental Affairs
T 502-627-2940
F 502-627-2550
sharon.dodson@eon-us.com

John Lyons, Director
Division For Air Quality
803 Schenkel Lane
Frankfort, Kentucky 40601

RE: SO_3 Mitigation Projects

Dear Mr. Lyons:

We appreciate your willingness to meet with us yesterday to discuss the status of our SO_3 mitigation efforts and obtain further clarification on the Cabinet's position on the issue of regulation and control of SO_3 emissions. As you know, as utilities have proceeded to install Selective Catalytic Reduction (SCR) controls in recent years to meet the NO_x reduction requirements of the NO_x SIP Call and Clean Air Interstate Rule (CAIR), there has been increasing scrutiny of SO_3 emissions associated with installation of SCR controls. We understand that the Division For Air Quality has been monitoring developments both at the federal level and in other states with respect to control of SO_3 emissions. Last year DAQ staff contacted E.ON U.S. and a number of other utilities in Kentucky to gather information on SO_3 emissions in an effort to identify instances where mitigation of SO_3 emissions may be required to protect human health and the environment.

As a follow up to those inquiries from DAQ, E.ON U.S. has assessed SO_3 emissions from its plants, undertaken studies to determine effective SO_3 mitigation options, and initiated planning for potential SO_3 mitigation projects at selected plants.

Based on our discussions with you and your staff, we understand that the Division interprets the general duty provisions of KRS Chapter 224 to require necessary and appropriate action on a case by case basis to mitigate SO_3 emissions that could potentially impact human health and the environment. In short, we understand that if a permittee fails to address SO_3 emissions that may potentially impact human health or the environment, DAQ reserves the right to take appropriate action under KRS Chapter 224 to compel compliance with this requirement. We would appreciate it if you would confirm our understanding of DAQ's interpretation of its authority to control SO_3 emissions as necessary to prevent or mitigate impacts on human health and the environment.

We are committed to working with the Division For Air Quality in a responsible manner to meet the air quality requirements of KRS Chapter 224 and applicable regulations. We will continue to keep you and your staff informed on the status of our SO_3 mitigation efforts.

Sincerely,

Sharon L. Dodson

Sharon L. Dodson, Director
Environmental Affairs

cc: Diana Andrews, Assistant Director

Exhibit SLD-4 – KYDAQ SO_3 Mitigation Response Letter

ERNIE FLETCHER
GOVERNOR

LAJUANA S. WILCHER
SECRETARY

COMMONWEALTH OF KENTUCKY
ENVIRONMENTAL AND PUBLIC PROTECTION CABINET
DEPARTMENT FOR ENVIRONMENTAL PROTECTION
DIVISION FOR AIR QUALITY
803 SCHENKEL LN
FRANKFORT, KY 40601-1403

May 19, 2006

RECEIVED
MAY 2 3 2006
ENVIRONMENTAL AFFAIRS
LG

Ms. Sharon L Dodson, Director
Environmental Affairs
E.ON U.S. LLC
220 West Main Street
Louisville, Kentucky 40202

Dear Ms. Dodson:

In response to your letter of May 12, 2006, the Division for Air Quality wishes to confirm the position taken by the Division at our meeting on May 11, 2006, with regard to SO_3 emissions from electric generating units in general and Trimble County Unit 1 in particular. Your letter accurately characterizes the concern we have regarding the potential health and environmental impacts that such emissions may pose. KRS 224.10-100, Powers and duties of cabinet, requires that we provide for the prevention, abatement, and control of air pollution. The emissions of SO_3 that may subsequently be converted to a fine acidic mist certainly falls within the purview of this statute. This is especially true given the fact that the stack plumes containing this acid mist have been shown to reach ground level in areas near the affected units. Therefore, it is necessary and appropriate that such emission be controlled.

The Division appreciated the efforts undertaken by E.ON U.S. to address this very significant issue in a proactive manner which will further the prevention or mitigation of impacts on human health and the environment. Please do keep the Division apprised of the status of these SO_3 mitigation projects as they progress.

Sincerely,

Diana J. Andrews

Diana J. Andrews
Assistant Director

DJA/cam

Exhibit SLD-5 – Mill Creek Station Agreed Board Order signed December 14, 2004

LOUISVILLE, KENTUCKY

AIR POLLUTION CONTROL DISTRICT

JERRY E. ABRAMSON
MAYOR

C. BRUCE TRAUGHBER
SECRETARY OF THE CABINET
FOR COMMUNITY DEVELOPMENT

ARTHUR L. WILLIAMS
DIRECTOR

January 12, 2005

Ms. Sharon Dodson
Director
Environmental Affairs
Louisville Gas & Energy, LLC
P.O. Box 32010
Louisville, Kentucky 40232

RECEIVED
JAN 17 2005
ENVIRONMENTAL AFFAIRS
LG&E

Re: Agreed Board Order dated December 15, 2004

Dear Sharon:

Enclosed please find the executed Agreed Board Order adopted December 15, 2004. Thank you for your and Jason's cooperation with this. Please don't hesitate to call me if you have questions or concerns.

Sincerely,

Terri Phelps

Terri E. Phelps

Enclosure

AGREED BOARD ORDER

LOUISVILLE METRO AIR POLLUTION CONTROL BOARD

This order is issued by the Louisville Metro Air Pollution Control Board (Board) pursuant to Kentucky Revised Statutes, Chapter 77 (Air Pollution Control).

COMPANY: Louisville Gas & Electric Company

RECEIVED
JAN 17 2005
ENVIRONMENTAL AFFAIRS
LG&E

FACILITY INVOLVED: Mill Creek Generating Station
14660 Dixie Highway
Louisville, Kentucky

REGULATIONS INVOLVED: 2.16 (Title V Operating Permits)

POLLUTANT: Particulate Matter (as measured by Opacity)

BACKGROUND AND DISCUSSION:

The Company operates a coal-fired steam electric generating station (the Station) pursuant to Air Pollution Control District (District) Operating Permit No.145-97-TV, which requires, among other things, that the Company demonstrate compliance with its opacity standard by installing and testing a continuous extractive opacity emission monitoring system in a stack at one of three plants owned by the Company before June 30, 2004. If, after testing, the extractive opacity monitoring (EOM) system is approved by the District, the permit requires the Company to install an EOM system in one stack at the Station by October 31, 2004, and to install an EOM system in each of the other three stacks at the Station by January 31, 2005, April 30, 2005, and July 31, 2005, respectively.

The Company notified the District by letter dated June 24, 2004, that it had installed and begun testing an EOM system at its Trimble County Station. There is a dispute between the District and the Company as to whether the testing was completed by June 30, 2004. The Company requested an extension of the deadlines in order to conduct further testing. The District has met with the Company and has agreed to an extension of time to test the EOM system and to submit the system for approval by the District.

In addition to the extension of time. this Agreed Board Order provides for the Company to (1) install and test a particulate matter continuous emissions monitoring system (PM CEMS); and (2) to install on all four stacks at the Station the monitors approved by the District.

The Company has advised the District that is has completed testing an EOM system and is awaiting results of the testing from the Electric Power Research Institute (EPRI). The Company has also agreed to install a PM CEMS for a trial evaluation by January 31, 2005. By September 1, 2005, the Company shall submit a report to the District evaluating the reliability of both the EOM and the PM CEMS systems based upon its testing conducted by that date. If the District approves either system as set forth herein, the Company shall install one of the approved systems as provided below.

On December 15, 2004, a public hearing was held before the Board on the proposed agreement. Based upon the evidence presented at that hearing, the Board determined that the proposed resolution and requirements were reasonable under the circumstances.

NOW THEREFORE, BE IT ORDERED THAT:

1. The Company shall be excused from compliance with the provisions of Title V Operating Permit No. 145-97-TV requiring testing of a continuous extractive opacity emission monitoring (EOM) system before June 30, 2004, and installing four continuous opacity monitoring systems for each of the four stacks by October 31, 2004, January 31, 2005, April 30, 2005, and July 31, 2005, respectively.

2. No later than January 31, 2005, the Company shall install a PM CEMS on one stack at the Station for testing and evaluation. No later than September 1, 2005, the Company shall submit to the District an evaluation of the EOM and the PM CEMS systems and a recommendation based upon the testing conducted by the Company. The District shall determine by November 1, 2005, whether to approve either system, and will specify whether the system shall be used to determine compliance or as an indicator of performance. If the District approves the use of either system as reliable and representative under appropriate regulatory standards, the Company shall install an approved system in one stack at the Station by January 31, 2006, and in the three remaining stacks by April 30, 2006, July 31, 2006, and October 31, 2006, respectively, unless the only approved system is not commercially available.

3. The requirement to install one of the systems will replace any requirement to operate any other continuous opacity monitoring system. If the District determines that neither the EOM system nor the PM CEMS can be used, even as an indicator of performance, or if other necessary regulatory approvals are not obtained, the Company shall install continuous opacity monitors in the precipitator pant leg ducts of each unit in accordance with the schedule in paragraph 2 of this Order.

4. The District shall issue a revised permit that reflects the provisions of this Order. However, failure of the District to revise the Company's permit shall not affect the Company's obligations to comply with this Order.

5. The Company shall be exempt from compliance with District Regulations 6.02, 7.02 and 7.06 to the extent necessary to comply with this Order.

6. The Company has reviewed this Order and consents to all its requirements and terms.

Further, the Company agrees to pay the cost of publishing legal notice of the public hearing.

7. In the event that it is necessary for the District to seek a court order to enforce this Order, the Company agrees to pay filing fees and costs of such action.

Dated this 15th day of December, 2004.

Louisville Metro Air Pollution Control Board

By: Karen Cassidy
Karen Cassidy
Chair

Louisville Gas & Electric Company

By: Sharon Dodson
Sharon Dodson
Director, Environmental Affairs

Louisville Metro Air Pollution Control District

By: Jerri Phelps for
Jesse Goldsmith, P.E.
Engineering/Enforcement Manager

Approved as to form and legality:

By:
Lauren Anderson
Assistant County Attorney

Exhibit SLD-6 – Approval Letter from Louisville Metro Air Pollution Control District for installation of particulate matter continuous emission monitors at Mill Creek Station

LOUISVILLE, KENTUCKY

AIR POLLUTION CONTROL DISTRICT

JERRY E. ABRAMSON
MAYOR

C. BRUCE TRAUGHBER
SECRETARY OF THE CABINET
FOR COMMUNITY DEVELOPMENT

ARTHUR L. WILLIAMS
DIRECTOR

November 1, 2005

RECEIVED
NOV 7 2005
ENVIRONMENTAL AFFAIRS
LG&E

Sharon L. Dodson
Director, Environmental Affairs
LG & E Energy LLC
220 West main Street
PO Box 32010
Louisville, Ky 40232

Reference: Approval of Alternative Continuous Opacity Monitoring

Dear Ms. Dodson:

The District is required by the Agreed Board Order with Louisville Gas and Electric Company, dated December 15, 2004, to provide determination and approval of alternative continuous opacity monitoring for the Mill Creek Generating Station. Both the Monitoring Device Recommendation document, dated August 31, 2005 and the SICK FWE 200 Particulate Monitor Summary Report dated August 23, 2005 have been reviewed by District staff and are under review by EPA Region 4.

The District has determined that the particulate matter continuous emissions monitor (PM CEM) is the preferred option for installation at Mill Creek. The linearity and correlation data are very favorable for reliable operation. The instrumentation is certainly capable of indicating real time boiler performance and compliance with applicable PM standards. The District authorizes Louisville Gas and Electric Company to proceed with the installation schedule of the PM CEM according to the schedule in the agreed order. This authorization is given with the understanding that all remaining qualification testing will be completed and approved in a timely manner. The process of amending the Title V operating permit will begin as soon as possible.

The Title V operating permit will be amended to show that the PM CEM are to be used to demonstrate compliance with applicable PM standards. The permit amendment will also show that the installation and operation of the PM CEM equipment shall replace any requirement to operate any other continuous opacity monitoring equipment. The District will add quarterly reporting and RATA requirements similar to current requirements for existing CEM equipment.

Opacity shall remain as a standard. Compliance with the opacity standard shall be determined by compliant PM CEM data and compliant Federal Reference Method 9 opacity observations as stipulated in the current permit. In the event that the company has attempted to perform FRM9s and were unable to do so, the satisfactory PM CEM data alone shall indicate compliance for that monitoring period. The company shall make reasonable effort to do FRM9s as stipulated and shall document those observations or reasons why a FRM9 was not possible.

It follows that a positive PM CEM reading shall demonstrate compliance with the PM standard, even if a FRM9 indicated non-compliance with the opacity standard at the same time. Similarly, a positive FRM9 reading shall demonstrate compliance with the opacity standard even if the PM CEM indicated non-compliance with the PM standard at the same time. If there is no FRM9 data to demonstrate compliance with the opacity standard and the PM CEM reading demonstrates non-compliance with the PM standard, then both PM and opacity will be evaluated as non-compliance.

The District intends to evaluate the performance and reliability of the PM CEM equipment over the next several reporting periods and will reevaluate the frequency of FRM9s during the Title V permit renewal process. During the renewal process, the District also intends to remove parametric monitoring of the electrostatic precipitators and the wet scrubbers as such monitoring would no longer be required for demonstration of compliance. Please advise if you have questions or concerns.

Sincerely,

Jess Goldsmith

Jesse M. Goldsmith, PE
Engineering Manager

cc: Art Williams LMAPCD

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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**

DIRECT TESTIMONY OF
JOHN P. MALLOY
DIRECTOR, GENERATION SERVICES
E.ON U.S. SERVICES INC.

Filed: June 23, 2006

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

A. My name is John P. Malloy. I am the Director of Generation Services for E.ON U.S. Services Inc. which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies"). My business address is 220 W. 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 testified several times including Case Nos. 2004-00421[1], and 2004-00426[2], the Companies' most recent Environmental Cost Recovery (ECR) applications.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following four exhibits:

Exhibit JPM-1	Louisville Gas and Electric Company's 2006 Environmental Compliance Plan
Exhibit JPM-2	Component Cost of Trimble County Unit 2 Air Quality Control System equipment
Exhibit JPM-3	Sargent & Lundy SO_3 Mitigation Study dated March 29, 2006

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

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

Exhibit JPM-4 *2006 SO_3 Mitigation Strategy for Kentucky Utilities and Louisville Gas and Electric*

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a description of the new and additional pollution control projects contained in LG&E's 2006 Environmental Surcharge Compliance Plan ("2006 Plan"). The 2006 Plan is attached as Exhibit JPM-1 for which LG&E is seeking environmental surcharge recovery. These projects are required to comply with the Clean Air Act as amended ("CAAA"), the Clean Air Interstate Rule ("CAIR"), the Clean Air Mercury Rule ("CAMR"), the Clean Air Visibility Rule ("CAVR") and other environmental requirements that apply to LG&E facilities used for the production of energy from coal as identified in the testimony of Ms. Dodson. I will outline the planning process and methodologies used in determining the most cost-effective means for meeting these environmental requirements and provide the timeframe for construction as well as the estimated cost of the projects.

2006 ENVIRONMENTAL COMPLIANCE PLAN

Q. Please provide an overview of the projects in LG&E's 2006 Environmental Compliance Plan.

A. The four projects contained in Exhibit JPM-1 and identified as LG&E Projects 18 through 21, are required in order for LG&E to comply with the CAAA, the CAIR, the CAMR, the CAVR, (also known as the Regional Haze Rule) and other environmental regulations applicable to LG&E power plants. The total capital cost of the new and additional projects to the Compliance Plan is estimated to be approximately $66.0 million.

Q. Please describe LG&E's 2006 Environmental Compliance Plan as shown in Exhibit JPM-1.

A. The new and additional pollution control projects in LG&E's Environmental Compliance Plan are shown in Exhibit JPM-1.

Column 1 assigns a number to the project for identification purposes in sequence with the projects from Case No. 94-332[3] (1 through 5), Case No. 2000-386[4] (6), Case No. 2002-00147[5] (7 through 10), and Case No. 2004-00421[6] (11 through 17).

Column 2 describes the air pollutant or waste / 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. Ms. Dodson's testimony describes in detail the environmental regulations creating the need for the new project.

---

[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*

[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*

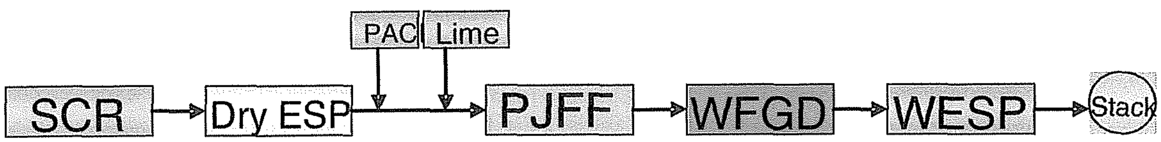
Column 6 identifies the environmental permit that demonstrates LG&E's project satisfies the environmental regulation. Ms. Dodson's testimony describes these environmental permits in further detail.

Column 7 shows anticipated completion date of the specific project.

Column 8 displays the estimated cost of the project.

Q. Please describe Project 18 in the LG&E 2006 Environmental Compliance Plan.

A. Project 18 is comprised of the Air Quality Control System ("AQCS") equipment necessary to operate Trimble County Unit 2 within the environmental limitations as set forth in the EPA Title V Operating Permit: V-02-043. Trimble County Unit 2 was granted a CCN on November 1, 2005 in Case 2004-00507[7]. The proposed AQCS equipment for the unit consists of a Selective Catalytic Reduction System ("SCR"), a Dry Electrostatic Precipitator ("DESP"), a pulverized activated carbon ("PAC") injection system for mercury control, a hydrated lime injection system, a Pulse Jet Fabric Filter ("PJFF"), a Limestone Forced Oxidation Wet Flue Gas Desulfurization System ("WFGD"), and a Wet Electrostatic Precipitator ("WESP"). The following provides a brief description of each component of the AQCS associated with Project 18:



[7] In the Matter of: *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity, and a Site Compatibility Certificate, for the Expansion of the Trimble County Generating Station*

Selective Catalytic Reduction System

The SCR is being installed to ensure compliance with NO_x limitations. Situated between the economizer outlet and the air pre-heater inlet, the SCR converts NO_x and ammonia to water and nitrogen. As part of the SCR project, low conversion catalyst and sorbent injection technology will be installed to mitigate the high SO_2 to SO_3 conversion problems associated with SCR operation

Dry Electrostatic Precipitator

The DESP is guaranteed to remove 90% of the particulate matter in the flue gas stream. The DESP uses electrical current to charge particles contained in the flue gas by passing them over discharge electrodes. The charged particles are then placed in an electrostatic field that drives them to collection plates (or curtains). After an increment of build-up, the collection surface plates are rapped to knock the particles into a hopper below for final byproduct disposal.

Pulverized Activated Carbon Injection

An activated carbon injection system will be installed to ensure Trimble Co. Unit 2 meets the mercury emission permit limitations across a full range of specified fuels. The PAC will be injected between the DESP and the PJFF. The PAC system is guaranteed to remove 90% of the total mercury and meet the permitted mercury emission limitation of 13×10^{-6} Lb/MWH.

Hydrated Lime Injection

Due to the range of fuels and operating parameters specified there are conditions in which condensation of sulfur trioxide (SO_3) may occur in the PJFF. To address the corrosion and operational issues related to sulfuric acid mist

(H_2SO_4) in the PJFF and to comply with relevant regulatory obligations a hydrated lime injection system will be installed. The sorbent will be directly injected in the flue gas stream upstream of the baghouse to chemically react with SO_3 and H_2SO_4 to produce filterable compounds which are then efficiently collected in a baghouse.

Pulse Jet Fabric Filter

Trimble County Unit 2 will be supplied with one PJFF system to control particulate matter and mercury emissions. The PJFF is comprised of two fields each containing six compartments. Each compartment contains 1,140 bags for a total of 13,680 bags in the PJFF. Flue gas with boiler fly ash, PAC and hydrated lime enter an inlet plenum and is distributed to each of the individual compartments. Flue gas enters the compartments and is evenly distributed via a baffle to the filter bag socks. The particle laden flue gas flows through the sides of the filters (where the particles collect and form a filter cake on the outside of the bags) and clean flue gas exits the top of the filter. In order to clean the filters, a pulse of air is directed into the top of the filters, causing a pressure change and dislodging the cake from the filter so that it falls into the collection hopper for disposal. Each filter bag is supported on a wire cage; the bags and cages are independently suspended from the top of each compartment.

There are numerous filter bag material alternatives for a baghouse. However, due to the high sulfur content of the coal to be burned, a degradation resistant fabric filter material will be required for this particular application.

The PJFF is designed and guaranteed for a filterable particulate matter emission rate of 0.015 lbs/mmBtu. This is tested at the outlet of the PJFF.

Wet Flue Gas Desulphurization

A WFGD system will be installed to ensure permitted sulfur dioxide emission limitations are met. The WFGD is designed to remove 99% of the SO_2 in the flue gas without the added costs of reaction enhancing chemicals. The WFGD is also effective in removing particulate matter, fluorides and oxidized mercury.

The WFGD consists of one absorber tower with two dual flow trays designed to treat 100% of the flue gas generated from the boiler. The absorber contains six limestone slurry spray levels and is designed to achieve 99% SO_2 removal with five spray levels in service; the sixth spray level is a spare. The WFGD system is designed for 5.5 lbs SO_2/mmBtu loading and 99% SO_2 removal.

Wet Electrostatic Precipitator

A WESP will be installed to ensure compliance with permitted particulate matter emission limitations. The WESP is designed to meet the permitted level of 0.0036 lbs/mmBtu of sulfuric acid at the stack. The WESP is also effective in removing many types of particulates, including acid mist, oil and tar based condensed aerosols, filterable particulates, and oxidized mercury.

A WESP charges particles in the flue gas by passing the particles over energized electrodes. The electrostatically charged particles then flow through an electrostatic field that drives them to oppositely charged collecting plates. The collection plates are continuously irrigated by an overhead washing system to eliminate concerns relating to contaminant build-up. The particle saturated water flows down the plates to the bottom of the WESP and to the reaction tank of the WFGD system.

The WESP is anticipated to have a removal impact on all particulate matter, both filterable and condensable. From the WESP, the flue gas flows to the stack and exits into the atmosphere. At the stack, the guaranteed total (filterable and condensable) particulate matter emission rate is 0.015 lbs/mmBtu.

Exhibit JPM-2 shows the capital costs of each of these components.

Q. Is this project required to comply with environmental regulations and permits?

A. Yes. As shown in the testimony of Ms. Dodson, the project is required to comply with the environmental regulations 401 KAR 51:017, 401 KAR 52:020 and Federal Regulation 40 CFR Part 52.21to determine the best available emission controls under Prevention of Significant Deterioration requirements. The requirements of the CAAA, CAIR, CAMR and CAVR also necessitate this project as described in Ms. Dodson's testimony.

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

A. Yes, as demonstrated in Case No. 2004-00507[8], the cost associated with Trimble County Unit 2, inclusive of cost associated with the above listed AQCS, is cost-effective.

Unlike previous environmental compliance projects which consisted of retrofits/modifications to existing units, the environmental project for TC2 was evaluated with the cost of the entire facility. Each prospective bidder on the TC2 project was required to construct a unit to meet the environmental requirements mandated by the USEPA. The Title 5 operating permit requirements cannot be met by purchasing allowances since the permit sets a maximum emission rate on the unit. In addition, the requirements are such that there is no fuel switch option other than Gas or Oil which would allow the unit to meet the SO_2 limitations in the permit. Therefore the required back-end environmental technologies were selected by each bidder on the TC2 project to most cost effectively comply with the permitting restrictions.

Q. Please describe Project 19 in the LG&E 2006 Environmental Compliance Plan.

A. Project 19 pertains to the mitigation of SO_3 on generating units where high sulfur coal is burned and NO_x emissions are controlled using an SCR during the ozone season: Mill Creek Units 3 and 4 and Trimble County Unit 1.

[8] In the Matter of: *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity, and a Site Compatibility Certificate, for the Expansion of the Trimble County Generating Station*

As a result of NO_x mitigation using the SCRs, SO_3 emissions have increased. With the addition of a third layer of SCR catalyst to maintain NO_x emission compliance, SO_3 emission levels further increased.

This unforeseen consequence of NO_x control can cause:

1) Increased air heater fouling and pluggage

2) Sulfuric acid accelerated corrosion in the duct work and balance of pollution control equipment post the SCR

3) Highly visible "blue plume" from the chimney discharge

To meet NOx compliance requirements as set forth in Title V permits and the general duty provisions of KRS Chapter 224 which require the company to mitigate emissions that could potentially impact human health or the environment, the Company has three alternatives:

1) Remove the SCR from service and purchase NO_x allowances

2) Remove the generating unit from service and purchase energy from the market to meet native load obligation

3) Install sorbent injection technology.

The installation of sorbent injection technology provides the lowest cost and least risk operational alternative for effective NO_x compliance.

As shown in Exhibit JPM-3 Sargent & Lundy SO_3 Mitigation Study and Exhibit JPM-4 2006 *SO_3 Mitigation Strategy for Kentucky Utilities and Louisville Gas and Electric*, sorbent injection is required at Trimble County Unit 1, Mill Creek Unit 3, and Mill Creek Unit 4.

Q. Is this project required to comply with environmental regulations and permits?

A. Yes. The project is required to comply with Mill Creek 3-4 and Trimble County 1 Title V Operating Permits (145-97-TV and V-02-043, respectively) and the general duty provisions of KRS Chapter 224 as discussed in Ms. Dodson's testimony

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

A. Yes. As shown in Exhibit JPM-3 *Sargent & Lundy* SO_3 *Mitigation Study* and Exhibit JPM-4 *2006* SO_3 *Mitigation Strategy for Kentucky Utilities and Louisville Gas and Electric*, the project provides the least cost alternative to mitigate emissions. Secondly, the reliance on market purchases of energy and/or NO_x allowances to meet Title V operating permit requirements is subject to volatile market conditions and eliminates the Company's ability to be self-compliant to environmental laws and regulations.

Q. Please describe Project 20 in the LG&E 2006 Environmental Compliance Plan.

A. The United States Environmental Protection Agency ("USEPA") has enacted regulations requiring continuous monitoring of mercury emissions from US Power Plants. In compliance with the CAMR, mercury monitors are required to be installed and certified prior to January 1, 2009 to facilitate full year compliance reporting and mercury allowance tracking on January 1, 2010. In order to add mercury monitors, the data loggers and software must be upgraded. This replacement must take place in 2006 to accommodate new recordkeeping and reporting software in 2007 and to be able to certify monitors for mercury in 2008. The new recordkeeping and reporting software also supports the new format changes that the USEPA has instituted for Electronic Data Reporting ("EDR").

Q. Is this project required to comply with environmental regulations and permits?

A. Yes. The project is required to comply with the environmental regulations as set forth in the CAMR and described in Ms. Dodson's testimony.

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

A. Yes. Project 20 provides the only means of compliance with the CAMR which requires monitoring, tracking, and reporting of mercury emissions.

Q. Please describe Project 21 –Particulate Monitors at Mill Creek Station - in the LG&E 2006 Environmental Compliance Plan.

A. Mill Creek Station converted all four generating units to "wet stack" operation requiring a change to monitoring methodologies. Particulate matter ("PM") monitoring devices were installed consistent with the Title V operating permit and an Agreed Board Order approved by the Louisville Metro Air Pollution Control

District ("LMAPCD"). The Agreed Board Order is included in Ms. Dodson's testimony as Exhibit SLD-4.

The PM monitors were installed in the stacks at the "official" continuous emissions monitoring platform. The PM monitors extract a sample of flue gas and dry the sample before going through a forward light scatter measurement section. The signal is then correlated to Particulate Matter. The monitors were tested using USEPA required tests and a testing protocol, Performance Specification 11.

Q. Is this project required to comply with environmental regulations and permits?

A. Yes. The project is required to comply with the environmental regulations related to Mill Creek's Title V Operating Permit (145-97-TV) as sponsored as an exhibit in Ms. Dodson's testimony.

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

A. Yes. Project 21 provided the only accurate measurement of PM approved by the Louisville Metro Air Pollution Control District ("LMAPCD") as reflected in Exhibit SLD-5.

Q. Describe the changes to the combined Companies emission allowance positions as it relates to the implementation of the CAIR.

A. The SO_2 position is consistent with the 2004 ECR filing (Case No. 2004-00421[9]) which considered the implementation of CAIR and sought approval for the purchase (including the inter-company transfers from KU) of emission allowances as required to meet Title V Operating Permit surrender requirements (LGE-Project 17).

The combined Companies NO_x allowance compliance strategy seeks to construct an SCR on Ghent Unit 2 Case No. 2006-00206[10]. The purchase of NO_x allowances, either inter-company from KU or market, will fall under the same project as identified above. Inter-company transfers of NO_x allowances will be handled consistent with the KPSC order in Case No. 2004-00421[11] which requires transfers at the weighted average cost. Currently, the combined Companies' NO_x allowance inventory consists solely of USEPA allocated allowances and therefore the cost basis is $0.00.

Q. Does this conclude your testimony?

A. Yes.

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

[10] 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*

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

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, John P. Malloy, being duly sworn, deposes and says he is Director, Generation Services for E.ON U.S. Services, Inc., 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.

John P. Malloy

John P. Malloy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of June 2006.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

TAMMY J. ELZY
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
My Commission Expires Nov. 9, 2006

Appendix A

John P. Malloy

Director – Generation Services
E.ON U.S.
220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40202
(502) 627-4836

Education

Indiana University, Master Business Administration – 2000
Indiana University, B.S. in Finance - 1998

Previous Positions

Louisville Gas and Electric Company, Louisville, Kentucky:

1998-2003 –	Maintenance Manager, Mill Creek
1996-1998 –	Manager Resource / Project Management, Louisville Gas and Electric - Fleet
1989-1996 –	Instrument and Electrical Supervisor, Mill Creek
1986-1989 –	Instrument and Electrical Technician, Mill Creek
1984-1986 –	Production Operations, Mill Creek
1983-1984 –	Coal Handling Operations, Cane Run
1980-1983 –	Instrument and Electrical Technician, Cane Run

Other Professional Associations

LG&E Credit Union

2001-Present	Chairman, Board of Directors
1998 - 2001	Treasurer, Board of Directors
1995-1998	Board of Directors

Exhibit JPM-1 – Louisville Gas and Electric Company's 2006 Environmental Compliance Plan

LOUISVILLE GAS AND ELECTRIC COMPANY

2006 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) Project Cost
18	Fly Ash, NO_x, SO_2, SO_3, Hg and Particulate	Selective Catalytic Reduction, Dry Electrostatic Precipitator, Pulverized Activated Carbon Injection, Hydrated Lime Injection, Fabric Filter Bag House, Wet Flue Gas Desulfurization, Wet Electrostatic Precipitator	Trimble Co. Unit 2	Clean Air Act Amendments (1990), Clean Air Interstate Rule (2005), Clean Air Mercury Rule (2005), Clean Air Visibility Rule (2005)	Title V Permit V-02-043 rev. 2	2010	$43.46 M (E)
19	NO_x/SO_3	Sorbent Injection	Mill Creek Unit 3, Mill Creek Unit 4, Trimble Co. Unit 1	KRS Chapter 224, General Duty Provisions, Clean Air Interstate Rule (2005)	Title V Permit 145-97-TV, Title V Permit V-02-043, rev. 2	2007	$18.66 M (E)
20	Mercury	Mercury Monitors	All Plants	Clean Air Mercury Rule (2005)	to be incorporated into Title V Operating Permits before 2009	2007	$2.84 M (E)
21	Fly Ash and Particulate	Particulate Monitors	Mill Creek Plant	40CFR Part 60, LMAPCD Regulations 6.02, 6.07, 7.01, and 7.06	Title V Permit 145-97-TV	2006	$.84 M (E)
							$65.79

**Sponsored by witness Dodson*

Exhibit JPM-2 – Component Cost of Trimble County Unit 2 Air Quality Control System Equipment

Louisville Gas and Electric's Allocation of Trimble County Unit 2 AQCS Cost

Equipment Type	$ Millions
Dry Electrostatic Precipitator (DESP)	$4.3
Pulverized Activated Carbon Injection (PAC)	$0.2
Pulse Jet Fabric Filter (PJFF) w/ Hydrated Lime	$4.3
Wet Flue Gas Desulphurization (WFGD)	$13.8
Wet Electrostatic Precipitator (WESP)	$8.7
Selective Catalytic Reduction System (SCR)	$3.5
ID Fans	$0.7
Stack Flue	$0.6
Miscellaneous Mechanical/Pipe	$4.3
Civil	$1.2
Electrical/Controls	$1.6
Miscellaneous Bulks	$0.3
Total	**$43.5**

Exhibit JPM-3 – Sargent & Lundy SO_3 Mitigation Study dated March 29, 2006

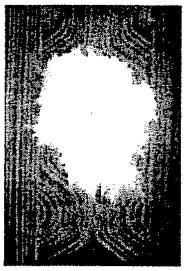
Exhibit JPM-3

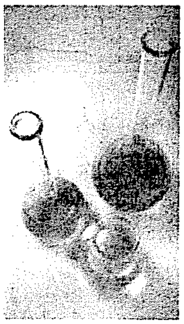
Sargent & Lundy SO_3 Mitigation Study is being provided electronically on CD

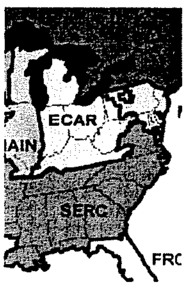
Exhibit JPM-4 – *2006 SO_3 Mitigation Strategy for Kentucky Utilities and Louisville Gas and Electric*

e·on | U.S.
Generation Services

Engineering
Laboratory
Planning







2006 SO_3 Mitigation Strategy for Kentucky Utilities and Louisville Gas and Electric

April 2006

Table of Contents

2006 SO_3 Mitigation Strategy for Kentucky Utilities and Louisville Gas and Electric

Executive Summary

Selective Catalytic Reactors (SCRs) have been installed at Ghent 1, 3, 4, Trimble 1 and Mill Creek 3 and 4 to reduce NOx emissions in compliance with the current regulations. The SCRs increase SO_3/H_2SO_4 in the flue gas which impacts particulate stack emissions. In order to mitigate the SCR impact on particulate emissions while maintaining NOx reduction, it is necessary to reduce the SO_3 levels in the flue gas.

E.On U.S. employed Sargent & Lundy (S&L) to evaluate all commercially available SO_3 reduction technologies and develop capital and O&M cost estimates for each technology to determine the most economic and technically effective approach to mitigate the impact of SO_3 on visible emissions for the SCR equipped units in the fleet. An economic evaluation was performed of the viable technologies to determine the best compliance option.

As a result of the study, sorbent injection was identified as a least cost option for units with cold-side ESP equipment. In order to select the most economic sorbent, it is recommended that KU and LG&E proceed with testing of hydrated lime and Trona injection at Ghent 1 and Trimble 1. Pending results of the testing the most economic sorbent will be selected as the technology of choice for all generating units with cold-side ESPs.

For Ghent 3&4, the units with hot-side ESP equipment, replacement of catalyst in conjunction with sorbent injection in the boiler and flue gas path was identified as the least cost option for SO3 reduction. In search of a lower cost option it is recommended that hydrated lime and Trona injection be tested at Ghent 3 & 4 while burning high sulfur coal. This approach is unproven but could save capital investment at these units if successful.

1.0 Background

During the combustion of sulfur-containing fossil fuels, a percentage of the sulfur dioxide (SO_2) formed is further oxidized to sulfur trioxide (SO_3). As the flue gas cools across the air heater and wet flue gas desulphurization equipment (WFGD), the SO_3 combines with flue gas moisture to form vapor-phase and/or condensed sulfuric acid (H_2SO_4). Sulfuric acid in flue gas has long been known to cause a variety of plant operation problems including plume visible emissions. The retrofit of selective catalytic reduction (SCR) units for nitrogen oxide (NOx) control can more than double flue gas SO_3/H_2SO_4 concentrations.

The SCR units at Ghent 1, 3, and 4, Trimble 1 and Mill Creek 3 and 4 increase SO_3/H_2SO_4 and thus particulate stack emissions. The amount of sulfur in the coal supply, the volume of SCR catalyst, along with various other equipment operating conditions, determines the total volume of SO_3 in the flue gas. Due to the specific conditions at Ghent 1 and Trimble 1, the addition of SCR equipment has increased flue gas SO_3 to a level that may result in visible emissions exceedences as measured by EPA Method 9. Under current conditions and with the existing fuel quality, the Mill Creek units and Ghent 3 and 4 are not experiencing visible emissions exceedences during SCR operation, though the particulate levels are elevated above normal operating levels. Plans to build FGD modules at Ghent 3 and 4 will result in a fuel switch to higher sulfur levels. This will increase the SO_3 and visible emissions levels at these units. The addition of catalyst in the Mill Creek SCRs to maintain NOx compliance will result in increased SO_3 and visible emissions.

E.On U.S. embarked on a SO_3 Mitigation Study to determine the most economic and technically effective approach to mitigate the impact of SO_3 on visible emissions for the SCR equipped units in the fleet. As part of the SO_3 mitigation study Generation Services employed Sargent & Lundy to investigate currently available SO_3 control technologies potential application at each unit. An economic evaluation of viable technologies was completed and combined with the technical evaluation to produce a lowest evaluated cost plan.

2.0 SO_3 Mitigation Alternatives

In order to mitigate SO_3/H_2SO_4 increases created by operation of the SCR, E.On U.S. has considered multiple alternatives.

1. Purchase of NOx Allowances
2. SO_3 Reduction Technologies
    a. Alkaline Additive Technology
    b. Sorbent Injection Technology
    c. Wet ESP Technology
    d. Low SO_2 to SO_3 conversion rate SCR catalyst
    e. Combination Technologies

2.1 Purchase NOx Allowances

By purchasing NOx allowances the SCR equipment can be turned off, reducing the formation of SO_3 in the flue gas. This option was considered during development of the NOx compliance strategy and was rejected. Dependence on the NOx allowance market results in the Companies being exposed to a volatile allowance market with significant price risk and the possibility that there will be minimal volumes of allowances available at any price. Installation of a combination of combustion NOx control equipment and SCR equipment has been demonstrated to be the least cost compliance strategy for NOx compliance.

2.2 SO_3 Reduction Technologies

EON-US employed Sargent & Lundy (S&L)to evaluate the feasibility of applying each commercially available SO_3 technology at each SCR unit in the combined company. As part of the evaluation S&L developed capital construction costing and annual operation and maintenance (O&M) costing for each technology at each unit. This data provides the basis for further technical and economic evaluation and development of an SO_3/visible emissions control strategy.

2.2.1 Alkaline Additive Technology

The alkaline components in flyash react with the SO_3 produced in the furnace to form sulfates, which are removed by the electrostatic precipitator (ESP). Introducing alkaline additives into the furnace allows higher SO_3 reaction and removal rates. These additives only capture boiler generated SO_3 and are not effective at capturing SCR-generated SO_3. Alkaline additives may also modify the slagging and fouling tendencies of the coal ash and increase furnace exit gas temperatures. Higher exit gas temperatures increase the SO_2 to SO_3 conversion in the SCR. For these reasons alkaline additives have been eliminated from consideration as viable SO_3 reduction options.

2.2.2 Sorbent Injection Technology

A variety of sorbents are available that can be added at various points in the flue gas path to reduce SO_3 and visible emissions. The following sorbent injection options were evaluated by S&L:

- Ammonia
- Humidification Water
- Hydrated Lime
- Magnesium Hydroxide
- Magnesium Oxide
- Micronized Limestone
- Sodium Bisulfite (SBS)
- Soda Ash
- Trona

Sorbent injection captures the SO_3 by reacting to form salts or sulfates which can be collected in the existing ESP, thus reducing the SO_3 impact on visible emissions. The use of sorbent injection technologies will be limited at Ghent Units 3&4 due to the hot-side ESPs, which are located upstream of the SCRs. Sorbent injection downstream of the ESP depends on particulate removal in the FGD and thus may be limited. A full assessment of each technology determined the viability at each unit as shown below in Table I.

Viability of Sorbent Injection Technologies

	Ghent - Unit 1	Ghent - Unit 3	Ghent - Unit 4	Mill Creek - Unit 3	Mill Creek - Unit 4	Trimble - Unit 1	Expected SO_3 Reduction
Ammonia	No	No	No	No	No	No	70%
Humidification	No	No	No	No	No	No	27%
Hydrated Lime	Yes	Yes*	Yes*	Yes	Yes	Yes	**90%**
Magnesium Hydroxide	Yes	Yes	Yes	Yes	Yes	Yes	90% Boiler/40-60%Overall
Magnesium Oxide	No	No	No	No	No	No	80%
Micronized Limestone	No	No	No	No	No	No	70%
Soda Ash	Yes	Yes*	Yes*	Yes	Yes	Yes	90%
Sodium BiSulfite (SBS)	Yes	Yes*	Yes*	Yes	Yes	Yes	90%
Trona	Yes	Yes*	Yes*	Yes	Yes	Yes	90%
Required SO_3 Reduction	90%	90%	90%	87%	85%	90%	

* Limited by capacity of FGD to collect particulate matter.

TABLE I

2.2.3 West ESP (WESP) Technology

Wet ESPs use water to clean collection plates while dry ESPs clean by mechanically rapping. Wet cleaning reduces particle re-entrainment and allows collection of fine particulate, mercury and aerosols. WESP technology is a primary candidate for compliance with proposed mercury and PM2.5 regulations. However, the capital cost of a wet ESP ranges from \$50 to \$70 million for the units in the KU and LG&E systems. For this reason it is prudent to avoid the installation of WESP technology until and unless additional regulations make this a cost-effective approach. Meanwhile, the Companies will pursue other means of reducing SO_3 and visible emissions.

2.2.4 Low Conversion Catalyst Technology

Catalyst manufacturers recognized the need for NOx reduction catalyst with lower SO_2 to SO_3 conversion rates and have brought 'low conversion' catalyst to market. New catalyst purchased for the LG&E and KU fleet in 2005 is low conversion type catalyst. By replacing existing catalyst with low conversion type, the level of SO_3 in the flue gas could be reduced by 28-43%. New catalyst alone will not reach the target of 5ppm SO_3 at the stack, but could work in combination with other technologies to reach the goal.

2.2.5 Combination Technologies

Sorbent injection technologies are potentially limited by the ability of the cold-side ESP or FGD (depending on the injection location) to collect the salts or sulfates produced. It may prove necessary to employ a combination of technologies to reduce the SO_3 to target levels, particularly at units with low ESP collection area. Table II identifies the technology combinations recommended by S&L in their evaluation.

Viability of Combination Technologies

	Ghent - Unit 1	Ghent - Unit 3	Ghent - Unit 4	Mill Creek - Unit 3	Mill Creek - Unit 4	Trimble - Unit 1	Expected SO_3 Reduction
Low Conversion Catalyst	Yes	Yes	Yes	Yes	Yes	Yes	28-43%
Combination Technologies							
Low Conv. Catalyst + Sorbent Injection	Yes			Yes	Yes	Yes	95%
Magnesium Hydroxide + Sorbent Injection	Yes			Yes	Yes		95%
Mag Hydroxide + Low Conv Catalyst + Sorbent Inj.		Yes	Yes				
Trona + Sorbacal (pending test results)		Yes	Yes				
Required SO_3 Reduction	90%	90%	90%	87%	85%	90%	

TABLE II

3.0 Cost of Particulate Control Alternatives

The Companies performed a full economic evaluation of all viable technologies to determine the present value of revenue requirements. The result of this evaluation is an economic ranking of viable technologies by unit. Table III-KU and Table III-LG&E summarize the results of the cost evaluation.

Kentucky Utilities Technology Ranking		
Economic Evaluation Results of all Viable Technologies		
Ghent 1	**PVRR**	**Rank**
Soda Ash	$19.88	1
LCC + Soda Ash	$21.62	2
LCC + Sodium BiSulfite	$29.29	3
LCC + Hyd Lime	$30.46	4
Sodium BiSulfite	$33.56	5
Magnesium Hydroxide + Soda Ash	$40.24	6
Hydrated Lime	$41.45	7
LCC + Trona	$42.26	8
Magnesium Hydroxide + Sodium BiSulfite	$50.03	9
Magnesium Hydroxide + Hydrated Lime	$53.58	10
Trona	$66.14	11
Magnesium Hydroxide + Trona	$69.93	12
Wet ESP (Horizontal)	$89.26	13
Wet ESP (Veritcal)	$108.54	14
Ghent 3	**PVRR**	**Rank**
LCC + Mag Hyd+ Soda Ash	$43.56	1
LCC + Mag Hyd+ Hyd Lime	$44.59	2
LCC + Mag Hyd+ Sodium BiSulfite	$45.55	3
LCC + Mag Hyd+ Trona	$48.92	4
Wet ESP (Horizontal)	$86.12	5
Wet ESP (Veritcal)	$108.79	6
Ghent 4	**PVRR**	**Rank**
LCC + Mag Hyd+ Soda Ash	$44.57	1
LCC + Mag Hyd+ Hyd Lime	$45.57	2
LCC + Mag Hyd+ Sodium BiSulfite	$46.77	3
LCC + Mag Hyd+ Trona	$50.45	4
Wet ESP (Horizontal)	$88.10	5
Wet ESP (Veritcal)	$113.22	6

Table III-KU

Note: "Sorbents" include Soda Ash, Sodium Bisulfite, Hyd Lime, Magnesium Hydroxide and Trona.

Louisville Gas & Electric Technology Ranking		
Economic Evaluation Results of all Viable Technologies		
Mill Creek 3	**PVRR**	**Rank**
Soda Ash	$15.91	1
LCC + Soda Ash	$20.26	2
Magnesium Hydroxide + Soda Ash	$24.57	3
Sodium BiSulfite	$24.82	4
LCC + Hyd Lime	$25.88	5
LCC + Sodium BiSulfite	$26.19	6
Hydrated Lime	$27.85	7
Magnesium Hydroxide + Sodium BiSulfite	$30.49	8
LCC + Trona	$35.18	9
Magnesium Hydroxide + Hydrated Lime	$41.13	10
Trona	$43.55	11
Magnesium Hydroxide + Trona	$50.41	12
Wet ESP (Veritcal)	$109.21	13
Mill Creek 4	**PVRR**	**Rank**
Soda Ash	$16.75	1
LCC + Soda Ash	$21.33	2
Magnesium Hydroxide + Soda Ash	$25.26	3
Sodium BiSulfite	$26.24	4
LCC + Sodium BiSulfite	$28.12	5
LCC + Hyd Lime	$28.18	6
Hydrated Lime	$29.33	7
Magnesium Hydroxide + Sodium BiSulfite	$31.30	8
LCC + Trona	$37.56	9
Magnesium Hydroxide + Hydrated Lime	$43.10	10
Trona	$44.52	11
Magnesium Hydroxide + Trona	$50.87	12
Wet ESP (Veritcal)	$109.04	13
Trimble 1	**PVRR**	**Rank**
Soda Ash	$15.49	1
LCC + Soda Ash	$19.32	2
Sodium BiSulfite	$21.05	3
Magnesium Hydroxide + Soda Ash	$25.89	4
Hydrated Lime	$26.64	5
LCC + Hyd Lime	$26.96	6
LCC + Sodium BiSulfite	$28.50	7
Magnesium Hydroxide + Hydrated Lime	$30.56	8
Magnesium Hydroxide + Sodium BiSulfite	$32.84	9
LCC + Trona	$36.90	10
Trona	$42.39	11
Magnesium Hydroxide + Trona	$52.63	12
Wet ESP (Veritcal)	$81.56	13

Table III-LG&E

Note: "Sorbents" include Soda Ash, Sodium Bisulfite, Hyd Lime, Magnesium Hydroxide and Trona.

4.0 Overall Evaluation of Top Ranking Technologies

The results of the economic evaluation must be considered in the context of economic and technologic risks and engineering evaluation. While all of the options evaluated are viable, the risks and potential side effects of each vary greatly. A summary of these risks is provided in Table IV, as provided in the S&L evaluation study report.

Risk Assessment Summary					
Technology	**Capital Cost**	**O&M Cost**	**Performance**	**Reliability**	**Overall**
Low Conversion Catalyst	Low	Low	Low	Low	Low
Sodium BiSulfite (SBS)	Low	Medium	Low	Medium	Low to Medium
Soda Ash	Low	Medium	Low	Medium	Low to Medium
Trona	Low	High	Low	Medium	Low to Medium
Hydrated Lime (Sorbacal)	Low	Medium	Medium	Medium	Medium
Magnesium Hydroxide	Medium	Medium	Medium	Medium	Medium
Wet ESP (Vertical)	High	Medium	Low	Medium	High
Wet ESP (Horizontal)	High	Medium	Low	Medium	High

Table IV

For all generating units with cold-side ESPs sorbent injection is the most economic technology. Soda ash, hydrated lime and sodium bisulfite are the top sorbent options. The cost estimates provided by S&L are based on predicted sorbent flow rates and average market prices. To make a final selection of the type of sorbent to be used at each unit, more accurate sorbent costs from suppliers must be obtained. Additionally, stoichiometric ratios for SO_3 reduction must be confirmed by testing.

Sorbacal is a type of hydrated lime with higher surface area and greater porosity. Sorbacal is expected to perform more efficiently than standard hydrated lime products. Testing of Sorbacal is being conducted at the Ghent 1 and Trimble 1 units. Initial results at Ghent 1 are favorable, while testing at Trimble 1 is currently underway. Long term testing (5 months) is being considered to fully evaluate the impact of Sorbacal injection on ESP performance. Current stoichiometric ratios for Sorbacal are below the hydrated lime estimates in the S&L study.

Trona sorbent injection is also being tested at Ghent 1 and Trimble 1. The price of Trona has dropped locally since the construction of a nearby distribution facility. Based on test results of Trona injection at these facilities stoichiometric ratios in the S&L study may be adjusted.

Refinement of the economic analysis after test results will be conducted to select the least cost sorbent injection option for cold-side ESP units.

For generating units with hot-side ESPs a combination of sorbent injection in the boiler and the gas path and catalyst replacement is the first choice technology on an economic basis.

It has been proposed that Sorbacal injection in combination with Trona may provide adequate SO_3 reduction on hot-side ESP units. The equipment arrangement on these units (Ghent 3 and 4) limits the use of sorbent injection downstream of the ESP. By injecting in two locations negative visible emissions impacts can be mitigated. A test of this combination is warranted before committing to the capital cost of catalyst replacement. Currently Ghent 3 and 4 are burning low sulfur coal and testing is not possible. When the flue gas desulphurization units have been installed and the units begin to burn high sulfur fuel a test will be conducted to prove the concept.

If the testing of split location sorbent injection is unsuccessful, Ghent 3 and 4 will require multiple reduction technologies to meet the target SO_3 emission level of 5 ppm. Magnesium hydroxide injection in the boiler coupled with replacement of existing NOx reduction catalyst with new 'low conversion' catalyst and sorbent injection in the gas path will be required.

5.0 Conclusion and Recommended Plan

The SCR units at Ghent 1, 3, 4, Trimble 1 and Mill Creek 3 and 4 increase SO_3/H_2SO_4 and thus particulate stack emissions. In order to mitigate the SCR impact on particulate emissions while maintaining NOx reduction, it is necessary to reduce the SO_3 levels in the flue gas.

All commercially available SO_3 reduction technologies were evaluated by S&L and the viable technologies were then subject to economic evaluation by the Companies. As a result it is recommended that KU and LG&E proceed with testing injection of various sorbents at Ghent 1 and Trimble 1. Pending success of the testing the most economic sorbent will become the technology of choice for all generating units with cold-side ESPs.

It is further recommended that a combination of Sorbacal and Trona injection be tested at Ghent 3 & 4 with high sulfur coal to prove the technology. Pending success of the testing, Sorbacal and Trona injection will become the technology of choice for Ghent 3 and 4. Failure of the tests will result in the need to inject sorbent in the boiler and flue gas path as well as replacement of the catalyst.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY OF
SHANNON L. CHARNAS
DIRECTOR, UTILITY ACCOUNTING AND REPORTING
E.ON U.S. SERVICES INC.

Filed: June 23, 2006

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

A. My name is Shannon L. Charnas. I am the Director of Utility Accounting and Reporting for E.ON U.S. Services Inc., 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. 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 2006 Environmental Compliance Plan ("2006 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 for the retirement of assets.

Recording and Tracking of Environmental Surcharge Expenses

Q. Is LG&E seeking recovery of operation and maintenance expenses associated with some to the Projects included in its proposed 2006 Plan?

A. Yes. The projects for which LG&E is seeking the recovery of operating and maintenance ("O&M") expense are Project Nos. 19 and 20. As explained in Mr. Malloy's testimony, Project 19 relates to the installation of Sorbent Injection equipment on Mill Creek Units 3 and 4 and on Trimble County Unit 1. This project includes O&M costs estimated to be $.9 million in 2007, $.9 million in 2008, and annual O&M costs beginning in 2009 of approximately $2.2 million.

The change in cost is due to the requirement to operate the SCRs year-round beginning in 2009, rather than just during the ozone season (May – September). Project No. 20 relates to the installation of mercury emission monitors on all generating units and includes annual O&M costs estimated to be approximately $612 thousand.

Q. How will LG&E identify the O&M expenses associated with Project Nos. 19 and 20 in its 2006 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 Nos. 502, Steam Expenses – Operation and 512, Maintenance of Boiler Plant, to identify and track the O&M expenses associated with the Sorbent Injection and mercury emission monitor projects, respectively, once they become operational. LG&E will use subaccounts to track specific expenses, and location codes to track expenses by unit. Since the Sorbent Injection equipment included in Project 19 and the mercury emission monitor equipment included in Project 20 are new, there is no expense currently in base rates for these units and LG&E will only include in its monthly surcharge filings the O&M associated with the new equipment.

No O&M expenses for Project Nos. 18 and 21 will be recovered through LG&E's environmental surcharge.

Q. Are there any changes necessary to account for NO_x allowance inventory?

A. Yes. In order to properly designate NO_x allowances for the annual and ozone season programs, two separate allowance inventory accounts will be tracked and reported on the forms as shown in Mr. Conroy's testimony.

Q. What book depreciation rates will be used in the calculation of the depreciation expense for the new and additional pollution control facility?

A. The book depreciation rate to be used for this equipment will be the existing depreciation rate for those assets. These rates are set forth in LG&E's Depreciation Study which is on file with and was approved by the Commission in Case No. 2001-141[1].

Q. What deferred income taxes are associated with pollution control facilities and equipment?

A. Deferred income taxes are recorded for all book versus tax temporary timing differences. These new pollution control facilities are eligible for accelerated tax depreciation and amortization. The pollution control facilities will generally fall into a 20-year Modified Accelerated Cost Recovery ("MACRS") life, or be eligible for U.S. Tax Code Section 169 amortization over a five-year or seven-year life.

Q. Please explain how property taxes associated with the new and additional pollution facilities are calculated.

A. Pollution control facilities located 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.

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[1] In the Matter of: *Application of Louisville Gas and Electric Company for an Order Approving Revised Depreciation Rates*

Costs Not Already Included In Existing Rates

Q. Are any of the capital expenditures for the new and additional pollution control facilities in this case already included in existing rates?

A. No. The current base rates were determined to be fair, just and reasonable by the Commission in its Order issued on June 30, 2004 in Case No. 2003-00433[2]. In making that determination, the Commission evaluated the reasonableness of LG&E's regulated return from Kentucky jurisdictional operations using the twelve month period ending September 30, 2003, as the test period, adjusted for known and measurable changes. No capital expenditures for the new and additional pollution control facilities in this case were incurred by LG&E during or prior to the twelve-month period ending September 30, 2003 or included as adjustments thereto.

Q. Are any of the operation and maintenance expenses for the new and additional pollution control facilities in this case already included in existing rates?

A. No. As previously explained, all O&M expenses for which LG&E is seeking recovery are associated with new pollution control projects. Therefore, LG&E's existing rates do not include any O&M for these facilities.

Q. Will the installation of the new pollution control facilities replace or cause existing facilities to be removed from service?

A. No. All assets for which LG&E is seeking recovery are new and do not result in the removal from service of any other assets.

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[2] In the Matter of: *An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*

Q. Will there be any operation and maintenance savings resulting from the installation of the equipment for the 2006 Plan that are already included in existing rates?

A. No. There are no O&M savings related to these projects.

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 she is Director, Utility Accounting and Reporting for E.ON U.S. Services Inc., that she 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 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 23rd day of June, 2006.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

TAMMY J. ELZY
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
My Commission Expires Nov. 9, 2006

APPENDIX A

Shannon L. Charnas
Director, Utility Accounting & Reporting
E.ON U.S. Services Inc.
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 Anderson 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 APPROVAL OF ITS 2006 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)))))	CASE NO. 2006-00208

DIRECT TESTIMONY OF
ROBERT M. CONROY
MANAGER, RATES
E.ON U.S. SERVICES INC.

Filed: June 23, 2006

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

A. My name is Robert M. Conroy. I am the Manager of Rates for E.ON U.S. Services Inc., 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 proceedings concerning the Companies' fuel adjustment clauses and 2004 amended environmental compliance plans ("2005 Plan").

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring four exhibits, identified as Exhibits RMC-1, RMC-2, RMC-3 and RMC-4. These exhibits are:

Exhibit RMC-1	Proposed LG&E Environmental Cost Recovery Surcharge Tariff
Exhibit RMC-2	Proposed LG&E Environmental Cost Recovery Surcharge Tariff (redline)
Exhibit RMC-3	Current LG&E Environmental Surcharge Monthly Reports
Exhibit RMC-4	Proposed LG&E Environmental Surcharge Monthly Reports

Q. What is the purpose of your testimony?

A. My testimony addresses how the environmental surcharge under LG&E Electric Rate Schedule Environmental Cost Recovery Surcharge ("ECR") tariff will be calculated to include the costs incurred in connection with the new and additional pollution control projects in LG&E's 2006 Environmental Compliance Plan ("2006 Plan").

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

A. Yes. LG&E is proposing a modification in the application of the ECR billing factor, and if approved, this modification will result in language revisions to the ECR tariff sheet. The proposed ECR Tariff is attached as Exhibit RMC-1. A redline version comparing the proposed ECR Tariff to the existing tariff is attached as Exhibit RMC-2.

Q. Will the methodologies for calculating the environmental surcharge change if the Commission approves recovery of LG&E's 2006 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[1], 2002-00147[2] and 2004-00421[3]. The calculation of the monthly Environmental Surcharge billing factor will continue to consolidate the 2001, 2003 and 2005 Environmental Compliance Plans and, if approved, the proposed 2006 Plan. However, LG&E is proposing a modification to the determination of R(m).

Q. Please explain the modification to the determination of R(m) that is being proposed by LG&E.

A. Under current practice, LG&E determines R(m) by deducting all non-jurisdictional revenues, all FAC revenues and all ECR revenues from each month's total revenues according to financial records. The remaining balance is treated as base revenues.

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[1] In the Matter of: *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*

That remaining balance, however, is actually net of small time-of-day ("STOD") program cost recovery factor ("PCRF"), merger surcredit ("MSR") and value delivery surcredit ("VDT") revenues. LG&E is proposing that the determination of R(m) be refined by removing the above referenced revenues from total revenue, leaving base revenues as the sum of customer charges, energy charges and demand charges. Therefore, if the Commission accepts LG&E's proposal, R(m) as determined in the monthly filings will closely approximate the revenues to which the monthly ECR billing factor is applied (i.e. base revenue plus fuel adjustment clause plus demand-side management plus STOD PCRF).

Q. Why is LG&E proposing to change the R(m)?

A. LG&E is proposing the change to R(m) so that the revenues used to determine the environmental surcharge factor are consistent with the revenues to which the environmental surcharge factor is applied on customer bills. Initially when the ECR was established, STOD, MSR and VDT were not established rate schedules and therefore were not included in the determination of R(m). As these rate schedules were established, the revenue (or surcredit) was included in R(m).

Q. What is the impact on the customer for the change in R(m)?

A. There will not be an impact on the customer by changing the determination of R(m). The proposed change to the determination of R(m) does not change the amount of the environmental costs (Net Jurisdictional E(m)) that LG&E is authorized to collect through the ECR billing factor.

Q. What is the benefit of the change?

A. As previously discussed, the change will more closely align the revenues used to determine the billing factor and the revenues to which the billing factor is applied. This alignment should somewhat reduce the variability of the monthly true-up adjustment for the over/under recovery of the monthly surcharge due to timing differences (from ES Form 2.00). There will still remain a variance due to the fact that a 12 month average revenue value is used to calculate the monthly factor and this factor is applied to actual monthly revenues.

Q. Will the monthly reporting forms used for calculating the environmental surcharge change if the Commission approves recovery of LG&E's 2006 Plan?

A. Yes. LG&E is proposing to change the format of several forms to reflect the recovery of the costs associated with the 2006 Plan and also edit the language used throughout the forms to provide consistency between the LG&E and KU filings. Exhibit RMC-3 contains the forms LG&E currently uses when filing its monthly environmental surcharge report. Exhibit RMC-4 shows the sample 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 2006 Plan.

A. The calculation of the monthly billing factor for recovery of the cost of LG&E's 2006 Plan will be consistent with the methodology approved by the Commission in Case No. 2004-00421[4] and used to calculate the recovery of the cost of LG&E's Post 1995 Environmental Compliance Plans. ES Form 1.00 will continue to show the

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

calculation of the Jurisdictional Environmental Surcharge Billing Factor using the same methodology previously approved by the Commission.

The 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 Case Nos. 2000-386[5], 2002-00147[6] and 2004-00421[7].

The plant, construction work in progress and depreciation expense for the 2001, 2003 and 2005 Plans previously reported on ES Forms 2.11 and 2.12 will be consolidated onto ES Form 2.11. LG&E is proposing to report the monthly plant, construction work in progress and depreciation expense for the additional projects in the 2006 Plan on ES Form 2.12.

The pollution control equipment operation and maintenance expenses for the 2001 and 2005 Plans are currently reported on ES Form 2.50. This form is being expanded to include the 2006 Plan projects for which LG&E is seeking to recover incremental operation and maintenance expenses as discussed in Ms. Charnas' testimony. The current month O&M expense for all plans shown on ES Form 2.50 will be utilized as the current month O&M on ES Form 2.40 in the determination of the pollution control cash working capital allowance.

Q. What modifications to the forms are necessary for the proposed change in the determination of R(m)?

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[5] In the Matter of: *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*

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

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

A. LG&E is proposing to modify ES Form 3.10 to specifically identify MSR, and VDT revenues in the section titled "Reconciling Revenues". Currently, those revenues are included in base revenues reported on ES Forms 3.00 and 3.10 even though the ECR is not applied to those revenues. Separate identification will result in an accurate match of base revenues used for the determination of the ECR billing factor and the method for applying the ECR billing factor on customer bills.

Both ES Form 3.00 and 3.10 are being further modified to separately identify DSM revenues and STOD PCRF revenues from base revenues leaving base revenue as the sum of customer, energy and demand charges.

Q. Is LG&E proposing to edit the language throughout the forms to be consistent between the LG&E and KU filings?

A. Yes. KU and LG&E are proposing to make changes to the forms in order to provide consistency between the two Companies. This consistency will facilitate the review process for both Companies and allow for easier comparison. It will also facilitate the Commission's review of the Companies monthly filings and the operation of the mechanism in the 6-month and 2-year review proceedings. In addition, by having both Companies' forms consistent, administration of the mechanism will be made easier and it will allow for the potential automation of our filing processes in the future. Due to the different projects that each Company has approval to include in the ECR, there will remain slight differences in the content of each form.

Q. Are there any other proposed changes to the Forms?

A. Yes. LG&E is proposing to add new form ES Form 2.32 and 2.33 to track and report NO_x emission allowance inventory, usage and purchases consistent with the SO_2

emission allowances reported on ES Form 2.31. As explained in Mr. Malloy's testimony, NO_x emission allowance purchases (either from the market or from KU) will be required. Currently there are NO_x allowances in inventory for the Ozone Season (May through September). ES Form 2.32 will be used to track and report the ozone season NO_x allowance inventory. Upon implementation of the Clean Air Interstate Rule, as discussed in Mr. Malloy's and Ms. Dodson's testimony, there will be an allocation of annual NO_x allowances and a separate inventory from the ozone season NO_x allowance inventory. As such, ES Form 2.33 will be used to track and report the annual NO_x allowance inventory.

Consistent with the Commission's Order of June 20, 2005 in Case No. 2004-00421[8] any purchases of allowances from KU will be at KU's weighted average cost of its emission allowance inventory. Currently there is a zero dollar value associated with LG&E's NO_x emission allowance inventory because the only NOx allowances held in inventory are those allocated by the Environmental Protection Agency at zero dollar value. The proposed new forms ES Form 2.32 and 2.33 are consistent with the Commission's approval of Project No. 17 in the June 20, 2005 Order in Case No. 2004-00421[9].

LG&E is also proposing to modify ES Form 2.30 in order to separately identify SO_2 and NO_x emission allowance inventory.

Q. Does the relief requested by LG&E in this case have any effect on the existing electric base rates?

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

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

A. No. Ms. Charnas' testimony affirms that none of the costs of the new and additional pollution control facilities was incurred prior to or during the 12-month period ending September 30, 2003 or included as adjustments hereto. Thus, none of these costs is already included in existing base rates.

The current base rates also do not include existing environmental surcharge revenues, expenses or assets associated with the proposed 2006 Plans. To the extent that the installation of the new and additional pollution control facilities causes existing facilities to be replaced or retired, the cost of which is already included in existing rates, LG&E will credit the amount of net plant balance of retired or replaced plant against the amount of the capital expenditure to be recovered through the surcharge in accordance with the Commission's Order of April 6, 1995 in Case No. 94-332[10] and its April 18, 2001 Order in Case No. 2000-386[11]. LG&E has been removing such amounts from the surcharge as necessary in the monthly calculation of the surcharge factor.

Q. Has LG&E estimated the impact of the new projects on the Environmental Cost Recovery tariff?

A. Yes. The estimated impact, upon approval by the Commission, on a residential customer using 1,000-kilowatt hours per month is expected to be an increase of $0.41 during 2007 with a maximum monthly impact estimated to be an increase of $0.81 in 2010. In addition to the projects associated with the 2006 Plan, LG&E has also

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[10] 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*

[11] In the Matter of: *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*

estimated the impact for those projects associated with the 2005 Plan[12] for the same time period. The estimated impact of those projects approved as part of the 2005 Plan is expected to be an increase of $0.11 during 2007 and $0.23 in 2010.

Q. Please summarize what relief LG&E is requesting from the Commission.

A. LG&E is seeking Commission approval of (1) the 2006 Plan proposed in this case for the purpose of recovering the costs of pollution control facilities in that plan through the environmental surcharge beginning with bills rendered on and after February 1, 2007; (2) the proposed ECR Tariff; and (3) the proposed reporting formats.

Q. Does this conclude your testimony?

A. Yes it does.

[12] Approved by the Commission in Case No. 2004-00421 by Order issued June 20, 2005

VERIFICATION

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

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says he is Manager, Rates for E.ON U.S. Services Inc., 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.

Robert M. Conroy
ROBERT M. CONROY

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of June 2006.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

TAMMY J. ELZY
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
My Commission Expires Nov. 9, 2006

APPENDIX A

Robert M. Conroy

Manager, Rates
E.ON U.S. Services Inc.
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

Center for Creative Leadership, Foundations in Leadership program, 1998.

Registered Professional Engineer in Kentucky, 1995.

Previous Positions

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.

Exhibit RMC-1 – Proposed LG&E Environmental Cost Recovery Surcharge Tariff

ECR

Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

To all electric rate schedules

RATE

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

$$CESF = E(m) / R(m) \qquad MESF = CESF - BESF$$

MESF = Monthly Environmental Surcharge Factor
CESF = Current Environmental Surcharge Factor
BESF = Base Environmental Surcharge Factor

Where 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 as set forth below.

DEFINITIONS

1) For all Plans, $E(m) = [(RB/12) (ROR + (ROR - DR) (TR / (1 - TR))] + OE - BAS$ T
   Where: T
   a) RB is the Total Environmental Compliance Rate Base. T
   b) ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the T overall all 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]. T
   d) TR is the Composite Federal and State Income Tax Rate. T
   e) OE is the Operating Expenses [Depreciation and Amortization Expense, Property Taxes, T Insurance 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 Case Nos. 2000-386, 2002-147, 2004-00421 and 2006-00208. T
   f) BAS is the total proceeds from by-product and allowance sales T

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor 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 T ending with the current expense month. Base revenue includes the customer, energy and T demand charge for each schedule to which this mechanism is applicable and automatic T adjustment clause revenues for the Fuel Adjustment Clause, the Demand-Side Management T Cost Recovery Mechanism and STOD Program Cost Recovery Factor as applicable for each T rate schedule. T

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

Exhibit RMC-2 – Proposed LG&E Environmental Cost Recovery Surcharge Tariff (redline)

Louisville Gas and Electric Company

Second Revision to Original Sheet No. 72
P.S.C. of Ky. Electric No. 6

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ECR
Environmental Cost Recovery Surcharge

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
To all electric rate schedules

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

CESF = E(m) / R(m)   MESF = CESF – BESF

MESF = Monthly Environmental Surcharge Factor
CESF = Current Environmental Surcharge Factor
BESF = Base Environmental Surcharge Factor

Where 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 as set forth below.

DEFINITIONS

1) For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE - BAS
   Where:
   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 all 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, Insurance 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 Case Nos. 2000-386, 2002-147, 2004-00421 and 2006-00208.
   f) BAS is the total proceeds from by-product and allowance sales

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor 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 schedule to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause, the Demand-Side Management Cost Recovery Mechanism and STOD Program Cost Recovery Factor 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.

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Date of Issue: June 23, 2006 | Issued By | Effective: With Bills Rendered On and After February 1, 2007
Canceling First Revision to Original Sheet No. 72
Issued June 28, 2005

John R. McCall, Executive Vice President
General Counsel and Secretary
Louisville, Kentucky
Issued by Authority of an Order of the KPSC in Case No. 2006-00208 dated

Exhibit RMC-3 – Current LG&E Environmental Surcharge Monthly Reports

ES Form 1.0

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Monthly Billed Environmental Surcharge Factor - MESF

For the Expense Month of

MESF = CESF - BESF

Where:

CESF = Current Period Jurisdictional Environmental Surcharge Factor

BESF = Base Period Jurisdictional Environmental Surcharge Factor

Calculation of MESF:

CESF, from ES Form 1.1	=	
BESF, from Case No. 2003-00433	=	2.38%
MESF	=	

Effective Date for Billing:

Submitted by: ______________________________

Title: Manager, Rates

Date Submitted: ______________________________

ES Form 1.1

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Calculation of E(m) and Jurisdictional Surcharge Billing Factor

For the Expense Month of

Calculation of Total E(m)

E(m) = [(RB / 12) (ROR-DR)(TR/(1-TR)))] + OE, 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

		Environmental Compliance Plans
RB	=	
RB / 12	=	
(ROR + (ROR - DR) (TR / (1 - TR)))	=	10 39%
OE	=	
BAS	=	
E(m)	=	

Calculation of Jurisdictional Environmental Surcharge Billing Factor

Retail Allocation Ratio for Current Expense Month	=	
Retail E(m) = Total E(m) x Jurisdictional Allocation Ratio	=	
Adjustment for Monthly True-Up (from Form 2 0)	=	
	=	
Net Retail E(m) = Retail E(m) minus Adjustment for Over/(Under) Recovery plus/minus Adjustment for Monthly True-Up	=	
Retail R(m) = Average Monthly Retail Revenue for the 12 Months Ending with the Current Expense Month	=	
Retail Environmental Surcharge Billing Factor: CESF = Net Retail E(m) / Retail R(m) ; as a % of Revenue	=	

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

	Environmental Compliance Plan	
Eligible Pollution Control Plant		
Eligible Pollution CWIP Excluding AFUDC		
Inventory-Emission Allowances per Form 2.31		
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		
Pollution Control Deferred Investment Tax Credit		
Subtotal		
Environmental Compliance Rate Base		

Determination of Pollution Control Operating Expenses

	Environmental Compliance Plan
Monthly Operations & Maintenance Expense	
Monthly Depreciation & Amortization Expense	
Monthly Property & Other Applicable Taxes	
Monthly Insurance Expense	
Monthly Emission Allowance Expense	
Monthly Permitting Fees	
Amortization of Mill Creek Ash Dredging	
Less : Reduction of O&M Expenses associated with 2003 Compliance Plan	$22,593
Less : Operating Expenses Associated with Retirements or Replacements	
Occuring Since Last Roll-In of Surcharge into Existing Rates	
Total Pollution Control Operations Expense	

Proceeds From By-Product and Allowance Sales

	Gross Proceeds	Sales Expenses	Net Proceeds
Allocated Allowance from EPA			
Scrubber By-Products Sales			
Total Proceeds from Sales			

True-up Adjustment: Over/Under Recovery of Monthly Surcharge Due to Timing Differences

A. MESF for December Expense Month	
B. Net Jurisdictional E(m) for December Expense Month	
C. Environmental Surcharge Revenue, current month (from Form 3.00)	
D. Retail E(m) recovered through base rates (Base Revenues, Form 3.0 times 2.38%)	
E. Over/(Under) Recovery due to Timing Differences ((D + C) - B)	
Over-recoveries will be deducted from the Jurisdictional E(m); under-recoveries will be added to the Jurisdictional E(m)	

ES FORM 2.11

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense - Post-1995 Plan

For the Month Ended

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Deferred Tax Balance as of	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)			
2001 Plan							
Project 6 - LGE NOx							
Subtotal							
Less Retirements and Replacement Subsequent to a 2001 Plan Roll-in							
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 Included in Base Rates							
Net Totals							

ES FORM 2.12

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense - 2005 Plan

For the Month Ended

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Deferred Tax Balance as of	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 Included in Base Rates							
Net Totals							

ES FORM 2.30

LOUISVILLE GAS & 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
Current Year			
2007			
2008			
2009			
2010			
2011			
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026 - 2034			

In the "Comments and Explanation" Column, describe any allowance inventory adjustment other than the assignment of allowances by EPA. Inventory adjustments include, but are not limited to, purchases, allowances acquired as part of other purchases, and the sale of allowances.

ES FORM 2.31

LOUISVILLE GAS & ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances - Current Vintage Year

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Steam Power)	Utilized (Other Power Generation)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: STEAM							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: OTHER POWER GENERATION							
Quantity							
Dollars							
$/Allowance							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
From KU:							
Quantity							
Dollars							
Cantor-Fitzgerald Market Price for SO2 emission allowances at [date]: [$ amount]							

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

Emission allowance inventory balance is due to the return of emission allowances from IMPA, received at current market value. Per the Commission's Order in Case No. 95-060, "An Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Company As Billed from August 1, 1994 to January 31, 1995," "...nor does returning the allowance in kind constitute a purchase." (Order at 5.) The Company concluded from this Order that allowance inventory and expense resulting from the return of allowances in kind is not recoverable through the ECR.

ES FORM 2.40

LOUISVILLE GAS & ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
O&M Expenses and Determination of Cash Working Capital Allowance

For the Month Ended

O&M Expenses	
11th Previous Month	
10th Previous Month	
9th Previous Month	
8th Previous Month	
7th Previous Month	
6th Previous Month	
5th Previous Month	
4th Previous Month	
3rd Previous Month	
2nd Previous Month	
Previous Month	
Current Month	
Total 12 Month O&M	
One Eighth (1/8) of 12 Month O&M Expense	1/8
Pollution Control Cash Working Capital Allowance	

ES FORM 2.50

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

O&M Expense Account	Mill Creek	Trimble County	Total
2001 Plan			
506104 - NOx Operation -- Consumables			
506105 - NOx Operation -- Labor and Other			
512101 - NOx Maintenance			
Total 2001 Plan O&M Expenses			
2005 Plan			
502006-Scrubber Operations			
512005-Scrubber Maintenance			
Ashpond Dredging Expense			
Total 2005 Plan O&M Expenses			

ES FORM 3.0

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Monthly Average Revenue Computation of R (m)
For the Month Ended

	Billed Retail Revenues					Wholesale Revenues	Total Company Revenues	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	Base Rate Revenues	Fuel Clause Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)	Total Excluding Environmental Surcharge (5)-(4)	Total Including Off-System Sales (See Note 1)	Total (5)+(7)	Total Excluding Environmental Surcharge (8)-(4)
Average Monthly Retail Revenues, Excluding Environmental Surcharge, for 12 Months Ending Current Expense Month.								
Retail Allocation Percentage for Current Month (Environmental Surcharge Excluded from Calculations): Expense Month Kentucky Retail Revenues Divided by Expense Month Total Company Revenues: Column (6) / Column (9) =								
						Note 1 - Excludes Brokered Sales, Total for Current Month =		$ -

ECR Form 3.10

LOUISVILLE GAS & ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Reconciliation of Reported Revenues

For the Month Ended

	Revenues per ES Form 3.0	Revenues per Income Statement
Kentucky Retail Revenues		
Base Rates		
Fuel Adjustment Clause		
Environmental Surcharge		
DSM DBA Billed		
Total Kentucky Retail 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		
Rate Refunds		
DSM Revenues from Lost Sales		
Merger Surcredit Settlement applied as bill credits in December		
Monthly Merger Surcredit Settlement Amortization		
Miscellaneous		
Total Company Revenues per Income Statement =		

Exhibit RMC-4 – Proposed LG&E Environmental Surcharge Monthly Reports

ES FORM 1.00

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Monthly Billed Environmental Surcharge Factor - MESF

For the Expense Month of

MESF = CESF - BESF

Where:

CESF	=	Current Period Jurisdictional Environmental Surcharge Factor
BESF	=	Base Period Jurisdictional Environmental Surcharge Factor

Calculation of MESF:

CESF, from ES Form 1.10	=
BESF, from Case No.	=
MESF	=

Effective Date for Billing:

Submitted by: ______________________________

Title: Manager, 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, 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

		Environmental Compliance Plans
RB	=	
RB / 12	=	
(ROR + (ROR - DR) (TR / (1 - TR)))	=	
OE	=	
BAS	=	
E(m)	=	

Calculation of Jurisdictional Environmental Surcharge Billing Factor

Jurisdictional Allocation Ratio for Expense Month	=	
Jurisdictional E(m) = E(m) x Jurisdictional Allocation Ratio	=	
Adjustment for Monthly True-up (from Form 2.00)	=	
Prior Period Adjustment (if necessary)	=	
Net Jurisdictional E(m) = Jurisdictional E(m) minus Adjustment for Monthly True-up plus/minus Prior Period Adjustment	=	
Jurisdictional R(m) = Average Monthly Jurisdictional Revenue for the 12 Months Ending with the Current Expense Month	=	
Jurisdictional Environmental Surcharge Billing Factor: Net Jurisdictional E(m) / Jurisdictional R(m) ; as a % of Revenue	=	

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

	Environmental Compliance Plan	
Eligible Pollution Control Plant		
Eligible Pollution CWIP Excluding AFUDC		
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

	Environmental Complaince Plan
Monthly Operations & Maintenance Expense	
Monthly Depreciation & Amortization Expense	
Monthly Property & 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 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	

Proceeds From By-Product and Allowance Sales

	Total Proceeds
Allowance Sales	
Scrubber By-Products Sales	
Total Proceeds from Sales	

True-up Adjustment: Over/Under Recovery of Monthly Surcharge Due to Timing Differences

A. MESF for two months prior to Expense Month	
B. Net Jurisdictional E(m) for two months prior to Expense Month	
C. Environmental Surcharge Revenue, current month (from ES Form 3.00)	
D. Retail E(m) recovered through base rates (Base Revenues, ES Form 3.00 times xx%)	
E. Over/(Under) Recovery due to Timing Differences ((D + C) - B)	
Over-recoveries will be deducted from the Jurisdictional E(m); under-recoveries will be added to the Jurisdictional E(m)	

ES FORM 2.11

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Deferred Tax Balance as of xx/dd/yyyy	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							
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							
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 - ES Form 2.11							

ES FORM 2.12

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Deferred Tax Balance as of xx/dd/yyyy	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 - ES Form 2.12							
Grand Total - ES Form 2.11 and 2.12							

ES FORM 2.30

LOUISVILLE GAS & 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							
2007							
2008							
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026 - 2034							

In the "Comments and Explanation" Column, describe any allowance inventory adjustment other than the assignment of allowances by EPA. Inventory adjustments include, but are not limited to, purchases, allowances acquired as part of other purchases, and the sale of allowances.

ES FORM 2.31

LOUISVILLE GAS & 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.

Emission allowance inventory balance is due to the return of emission allowances from IMPA, received at current market value. Per the Commission's Order in Case No. 95-060, "An Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Company As Billed from August 1, 1994 to January 31, 1995," "...nor does returning the allowance in kind constitute a purchase." (Order at 5.) The Company concluded from this Order that allowance inventory and expense resulting from the return of allowances in kind is not recoverable through the ECR.

ES FORM 2.32

LOUISVILLE GAS & 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 & 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 & 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	

ES FORM 2.50

LOUISVILLE GAS & 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				
506104 - NOx Operation -- Consumables	[redacted]			
506105 - NOx Operation -- Labor and Other	[redacted]			
512101 - NOx Maintenance	[redacted]			
Total 2001 Plan O&M Expenses	[redacted]			
2005 Plan				
502006-Scrubber Operations	[redacted]	[redacted]		
512005-Scrubber Maintenance	[redacted]	[redacted]		
Ashpond Dredging Expense	[redacted]		[redacted]	
Total 2005 Plan O&M Expenses	[redacted]			
2006 Plan				
506109 - Sorbent Injection Operation	[redacted]			
512102 - Sorbent Injection Maintenance	[redacted]			
506110 - Mercury Monitors Operation				
512103 - Mercury Monitors Maintenance				
Total 2006 Plan O&M Expenses				

Current Month O&M Expense for All Plans	

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)	(11)
Month	Base Rate Revenues	Fuel Clause Revenues	DSM Revenues	STOD Program Cost Recovery Factor Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)+(5)+(6)	Total Excluding Environmental Surcharge (7)-(6)	Total Including Off-System Sales (See Note 1)	Total (7)+(9)	Total Excluding Environmental Surcharge (10)-(6)
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 (8) / Column (11) =										
								Note 1 - Excludes Brokered Sales, Total for Current Month =		

ES FORM 3.10

LOUISVILLE GAS & ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Reconciliation of Reported Revenues

For the Month Ended:

	Revenues per ES Form 3.00	Revenues per Income Statement
Kentucky Retail Revenues		
Base Rates (Customer Charge, Energy Charge, Demand Charge)		
Fuel Adjustment Clause		
DSM		
STOD Program Cost Recovery Factor		
Environmental Surcharge		
Total Kentucky Retail 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		
Rate Refunds		
Merger Surcredit		
Value Delivery Surcredit		
Miscellaneous		
Total Company Revenues per Income Statement =		