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Robert M. Conroy
Director - Rates
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Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40602

November 17, 2009

RE: ***THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2009 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE***
CASE NO. 2009-00197

Dear Mr. DeRouen:

Please find enclosed and accept for filing the original in hardcopy and eight (8) copies of KU's Title V Permit Modification for the Addition of a SCR for the Brown Unit 3, in the above-referenced matter.

Should you have any questions concerning the enclosed, please contact me at your convenience.

Sincerely,

Robert M. Conroy

Enclosures

cc: Parties of Record

an e·on company

220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40232

<u>CERTIFIED MAIL</u>
<u>CERTIFIED NUMBER 7006 2760 0005 5303 8699</u>
<u>RETURN RECEIPT REQUESTED</u>

July 9, 2009

Mr. Jim Morse
Permit Review Branch
Kentucky Division for Air Quality
200 Fair Oaks Lane
Frankfort, KY 40601

RE: Modification to Permit V-03-023
I.D. # 21-167-00001
PSD Construction Permit Application/Title V Operating Application for the Addition of a SCR Control for E.W. Brown Unit 3

Dear Mr. Morse:

Section XVI of the Consent Decree between U.S. EPA and Kentucky Utilities (KU) for the E.W. Brown Station requires that KU obtain a construction permit for a SCR/pollution control device for E.W. Brown Unit 3. The proposed addition of this pollution control device is a major modification to an existing source, and thus is subject to Prevention of Significant Deterioration (PSD) review.

Attached please find KU's completed PSD permit application/Title V operating permit application seeking permission to commence construction on the new SCR control, along with an SO3 mitigation device, for E.W. Brown Unit 3. These completed forms constitute a revision to the original Title V permit application for the E.W. Brown Generating Station, filed with your office in December of 1996. The initial Title V Permit was issued March 1, 2005. In addition to this PSD application, a Title V renewal permit application will be submitted within the next several weeks.

The application has been signed by Ralph Bowling, the responsible official (designated representative) for KU's E.W. Brown Generating Station.

For your convenience, an electronic copy of the application has been placed on a CD and can be found in the inside front binder pocket. If you have any questions, please feel free to contact me (502-627-2343) or Gary Revlett (502-627-2357) regarding any questions.

Sincerely,

Marlene Zeckner Pardee
Senior Environmental Scientist

C:\DOCUMENTS AND SETTINGS\E005919\DESKTOP\SCR APPLICATION\EW BROWN PSD MOD COVERLETTER JULY 7 2009.DOC

CC:
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Mr. Ben Markin
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Kentucky Division for Air Quality
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Frankfort, KY 40601

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Chief, Environmental Enforcement Section
Environment and Natural Resources Division
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P.O. Box 7611, Ben Franklin Station
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DJ# 90-5-2-1-06837

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Director
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Sam Nunn Atlanta Federal Center
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Atlanta, GA 30303-8960

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William Bumpers
Baker Botts LLP
The Warner
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Kentucky Utilities Company

E.W. Brown Generating Station

Title V Permit Modification for Addition of
SCR for E.W. Brown Unit 3
Submitted to Kentucky Division for Air Quality
July 2009

Table of Contents

1.0 Introduction

Kentucky Utilities (KU), as operator of the E.W. Brown Generating Station located in Harrodsburg, Kentucky, is submitting a Prevention of Significant Deterioration (PSD) air permit application for the construction of a selective catalytic reduction device (SCR) with a sulfur trioxide (SO_3) mitigation system for E.W. Brown Unit 3. The SO_3 mitigation system is being proposed to control sulfur trioxide and sulfuric acid mist (H_2SO_4).

In 2008, KU received a consent decree for E.W. Brown Unit 3. On March 17, 2009, the consent decree was entered by the Court; hence, the clock began for the requirements noted in the consent decree. One of the requirements noted under section IV of the consent decree was to install and continually operate a SCR for Unit 3 by Dec. 31, 2012. Hence, KU is requesting approval of this PSD permit application to construct a SCR with SO_3 mitigation for E.W. Brown Unit 3. Section XVI of the consent decree states that KU must secure a permit to authorize construction or operation of any device required by the consent decree, including all preconstruction, construction, and operating permits required under state law, and that the application must be submitted in a timely manner.

Section XVI of the consent decree, states that within one hundred eighty days after entry of the consent decree or at the time that KU submits it Title V renewal permit application (expires March 1, 2010), whichever is later, KU shall amend any applicable Title V permit application, or apply for amendments of its Title V permit, to include a schedule for all unit-specific and plant – specific performance, operational , maintenance, and control technology requirements established by the consent decree including, but not limited to, required emission rates, removal efficiencies, and Unit Annual Tonnage Limitations for SO_2 and NO_x, and the requirements pertaining to the use and surrender of NO_x Allowances.

Due to the need to obtain a construction permit for the SCR and SO_3 mitigation system so that the SCR and SO_3 mitigation system is in operation by December 31, 2012, KU has decided to request a PSD for the construction of the SCR andSO_3 mitigation system and to submit a Title V Renewal Permit prior to September 1, 2009, to allow the Kentucky Division for Air Quality sufficient time for the review/approval of the permit applications.

2.0 Project Characterization

This section briefly characterizes the Project, the addition of a SCR/SO_3 mitigation system for E.W. Brown Unit 3. It includes a general description of Unit 3, location, local air quality status, and the applicability of New Source Review (NSR); and emission calculations for Prevention of Significant Deterioration (PSD) regulated pollutants emitted as the result of the additional pollution control devices (SCR and SO_3 mitigation system).

2.1 Project Location

The Project will be located at KU's E.W. Brown Generating Station, which is located in Burgin, Kentucky (Mercer County). The plant is approximately twenty-five miles southwest of Lexington, Kentucky. See Appendix D.

2.2 Project Description

Unit 3 is an existing unit (construction commenced July 19, 1971). It is a pulverized coal-fired, dry bottom, tangentially fired indirect heat exchanger, which is equipped with an electrostatic precipitator and low nitrogen oxides burners. A wet flue-gas desulphurization system is currently under construction for Units 1, 2, & 3.

This PSD application requests approval for the construction and operation of a SCR/SO_3 mitigation to control NO_X and sulfuric acid mist, a secondary pollutant, which is created as the result of adding the SCR pollution control device as required by the E.W. Brown Consent Decree.

The SCR System and Ammonia Storage contract has not been awarded; a Request for Proposal was sent to six technology suppliers on June 12, 2009. The Engineering, Procurement, and Construction of the SCR and balance of plant activities will be competitively bid in the third quarter of 2009. Contract release on the SCR is anticipated in the fourth quarter of 2009. The SO_3 mitigation system contract has not been awarded, but KU anticipates that it will be similar to the systems installed for Louisville Gas and Electric's Trimble County Generating and KU's Ghent Generating plants, which were supplied by Noltec. The SO3 mitigation contract will follow the SCR contract release as the design and implementation of this system is much shorter.

2.3 Project Emissions

The SCR system being installed per the USEPA and KU Consent Decree will reduce NO_X emissions at E.W. Brown Unit 3. Baseline NO_X emissions (prior to the operation of the SCR) are calculated as the highest "annual" average emission rate in tons per year, based on the actual emissions determined over a 24-month consecutive period during the most recent 5-year period preceding the contemporaneous emissions change. Due to the timing of the Project, the most recent "actual" emissions period starts in March 2009 and goes back 5 years through March 2004. The annual NO_x emission rate after the SCR operation was calculated based on expected boiler heat input for the 5-year period after SCR operation and meeting the 0.07 lb/mmBtu emissions rate listed in the Consent Decree. See Table 2-1 for a summary of the baseline and maximum projected NO_x emission rate in tons per year. Detailed worksheets showing calculation assumptions and methodology are contained in Appendix E.

A coincidental increase in emissions of sulfuric acid mist (H_2SO_4) will be generated from the operation of the selective catalytic reduction (SCR) system used specifically for E.W. Brown Unit 3. Post SCR operation emissions were calculated for the Unit 3 combustion source (with associated control devices) based on projected fuel burn rates and projected fuel quality, engineering design estimates for control device performance, known or industry accepted pollutant production/generation rates, and standard engineering calculation methodology.

As listed in the BACT determination (Section 3.0), H_2SO_4 emissions will be controlled using a combination of the wet flue gas desulphurization device (wet FGD) and a sorbent injection system. See Table 2-2 for a summary of the controlled and uncontrolled H_2SO_4 maximum projected emissions rates for the Project. Detailed worksheets showing calculation assumptions and methodology are contained in Appendix E.

Table 2-1
E.W. Brown Unit 3 PSD Emissions Comparison
Associated with SCR Project

Pollutant	Baseline tpy [(a)]	Baseline lb/hr [(a)]	Maximum Projected Unit 3 Boiler tpy	Maximum Projected Unit 3 Boiler lb/hr	Emissions Increase / Decrease	PSD Review Required (Yes/No)
H_2SO_4	457.6	114.5	596.8 [(d)]	151.3 [(b)]	Increase	Yes
NO_x	4,356.3	1,062.8	1,024.0 [(c)]	259.6 [(b)]	Decrease	No

(a) Baseline values of H_2SO_4 are prior to use of higher sulfur coal, wet FGD, SCR, and sorbent injection.
(b) Maximum projected lb/hr based on annual average tons per year (tpy).
(c) Maximum projected NO_x tpy based on meeting 0.07 lb/mmBtu emission rate per Consent Decree.
(d) Maximum projected tpy based on use of high sulfur coal, SCR, and wet FGD

2.4 Maximum Project PSD Pollutant Potential to Emit

Potential to emit (PTE) calculations for H_2SO_4 were performed based on 8,760 hours of operation, maximum boiler heat input, maximum coal fuel throughput, industry standard pollutant production rates, and design or expected control device efficiencies. See Table 2-2 for a summary of the Project PTE estimates for H_2SO_4. Detailed PTE worksheets showing calculation assumptions and methodology are contained in Appendix E.

Table 2-2
EW Brown Unit 3 Project H_2SO_4 Uncontrolled,
Controlled, and Potential to Emit

Pollutant	Maximum Projected Unit 3 Boiler tpy	Maximum Projected Unit 3 Boiler lb/hr	Unit 3 Boiler PTE tpy [(b)]	Unit 3 Boiler PTE lb/hr
H_2SO_4 Uncontrolled [(a)]	4,110.9	1,042.3	6,641.2	1,516.3
H_2SO_4 Controlled	596.8	151.3 [(c)]	964.3	220.2

(a) Uncontrolled values do not include reduction due to wet FGD or sorbent injection.
(b) PTE tpy in Table 2-2 correspond to the values as listed in the BACT analysis (BACT analysis includes a maximum hourly PTE and a 75% capacity factor; also represents the "uncontrolled" value with only a wet FGD).
(c) Maximum projected lb/hr H_2SO_4 based on annual average tpy.

2.5 PSD/NSR Major Modification Determination

As shown in table 2-1, the Project's post-change controlled H_2SO_4 emissions are greater than baseline amount by more than the 7 ton significance level allowed by PSD. Therefore, the project is subject to PSD review for H_2SO_4. See Table 2-1 for a summary of the baseline and post-change controlled H_2SO_4 emissions.

For the purpose of determining the difference in the pre-change "actual" baseline emissions and the post change "future actual" emissions, the WEPCO rule methodology was followed for calculating actual versus future projected emissions for an electric utility steam generating unit (EGU).

For an EGU, the baseline period actual emissions are calculated as the highest "annual" average emission rate in tons per year, based on the actual emissions determined over a 24-month consecutive period during the most recent 5-year period preceding the contemporaneous emissions change. Due to the timing of the project, the most recent "actual" emissions period starts in March 2009 and goes back 5 years through March 2004. The baseline annual NO_x emissions are 4,356 tons and the baseline annual H_2SO_4 emissions are 457.6 tons.

The post change future actual emissions is a projection of an annual rate in tons per year, that reflects the maximum annual emissions expected to occur during any one of the 5 years immediately after the change. The post-change rolling annual future actual emissions were calculated started in January 2013 (after SCR operation) through the 5 year period ending in December 2017. Based on the projected future utilization of Brown Unit 3 the projected maximum future NO_x emissions are 1,024.0 tons per year and 596.8 tons per year of sulfuric acid. This change represents a predicted decrease in NOx emissions following the installation of the SCR of 3,332.3 tons per year and the predicted increase in H_2SO_4 emissions with BACT control of 139.2 tons per year. In addition to calculating the projected future maximum yearly emissions, the Potential-To-Emit (PTE) was also calculated for H_2SO_4. This information along without calculated uncontrolled H_2SO_4 emissions in provided in Table 2-2. Detailed PSD actual (baseline) and future actual emissions showing calculation assumptions and example calculations are presented in Attachment E.

2.6 Local Air Quality Attainment/Nonattainment Status

As indicated in Table 2-1 the calculated increase in H_2SO_4 emissions is 139.2 tons per year and thus the proposed project will be a major modification under New Source Review (NSR) regulations, and will be subject to the PSD review program for H_2SO_4.

Accordingly, this application contains the following analyses to support a complete and thorough review of the Projects PSD air permit application:

- Best Available Control technology (BACT) Analysis
- Additional Impact Analysis
- Class II Area Impact Analysis
- Ambient Air Quality Impact Analysis

2.7 Federal and State Air Quality Requirements

Air quality permitting in Kentucky is under the jurisdiction of KDAQ. The USEPA has given KDAQ authority to implement and enforce the federal CAA provisions and state air regulations under its approved SIP. KDAQ will be responsible for the review of this application and the issuance of an air permit to construct and operate the pollution control devices for KU's E.W. Brown Unit 3. The following subsections discuss the applicable federal and state air quality programs, regulations, and standards, which relate to this project.

2.7.1 Federal Clean Air Act Requirements

The following subsections discuss the applicable federal regulations and how KU proposes to comply with the regulations for E.W. Brown Units 3.

2.7.1.1 New Source Review (NSR) Applicability

The federal CAA NSR provisions are implemented for new major stationary sources and major modifications under two programs: the PSD program outlined in 40 CFR 52.21, and the nonattainment NSR program outlined in 40 CFR 51 and 52.

The PSD program is designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the NAAQS, while providing a margin for future industrial and commercial growth. PSD applies to any new major stationary sources and any major modifications at an existing major source that occur in an area designated as attainment. As noted in Section 2.5, the E.W. Brown project is in attainment areas with respect to all pollutants. As such, PSD review will apply to the Project as a major modification.

A major stationary source is defined as any one of the listed major source categories which emits or has the PTE of 100 tpy or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the stationary source does not fall under one of the listed major source categories (i.e., fossil fuel fired boilers with greater than 250 mmBtu/hr heat input), and has a PTE of greater than 100 tpy for at least one regulated pollutants, it is classified as a major stationary source.

The only PSD pollutant of concern is sulfuric acid mist (H_2SO_4), which is a secondary pollutant that will be created as the result of adding the SCR. The significance level for H_2SO_4 is 7 tons per year. The PSD review consists of a best available control technology (BACT) analysis for sulfuric acid mist (H_2SO_4).

2.7.1.2 1990 CAA Title V

40 CFR Part 70, Title V of the CAA established an air quality operating permit program that provides a central point for tracking all applicable air quality requirements for every source required to obtain a permit. Each state is required to have a Title V operating permit program. In Kentucky's Title V operating permit program, KDAQ administers the construction permits and operating permits for Title V sources thought a "parallel review" process, which means that the construction and operating permit requirements are implemented and enforced through a single Title V Permit.

2.7.1.3 Compliance Assurance Monitoring – 40 CFR Part 64

In conjunction with the significant revision to the Title V Permit, a compliance assurance monitoring (CAM) plan in accordance with 40 CFR, Part 64, is required for the Project. The CAM rule became effective November 21, 1997. CAM applies to each pollutant specific emission unit (PSEU) that meets, the following three conditions:

1. Is subject to an emission limitation or standard, and
2. Use a control device to achieve compliance , and
3. Has precontrol emission that exceed or are equivalent to the major source threshold

The following PSEU are excluded from CAM rule:

1. Those subject to 111 or 112 standards promulgated after November 15, 1990, since those standards have been and will be designed with monitoring that provides a reasonable assurance of compliance.
2. Those subject to the acid rain program, emission trading programs such as acid rain programs, emission caps, or continuous compliance determination method for compliance, because CAM is believed to be redundant for those units.
3. Certain municipally owned utility units, as defined in 40 CFR 72.2, which produce electricity during periods of peak electrical demand or emergency situations, since these periods or situations are infrequent.

Uncontrolled emissions of sulfuric acid mist, a regulated pollutant, will exceed the 100 ton Part 64 major source threshold. Hence, CAM will apply to H_2SO_4 emissions. A CAM plan for H_2SO_4 emissions is attached in Appendix G.

2.7.2 Kentucky State Air Quality Requirements

KDAQ has permitting and review authority for all air quality projects in Kentucky through the USEPA approved SIP. Additionally, KDAQ has promulgated regulations for new and modified air pollutant sources, which are published in Kentucky Administrative Regulations (KAR), Title 401 Chapters 50 and 68. Several of these regulations have specific requirements regarding allowable emission rates and require air quality impact analyses. The regulations applicable to the E.W. Brown emission Unit 3 project are discussed in the following subsections.

2.7.2.1 Kentucky – Permit Registrations and Prohibitory Rules

KAR Chapter 52, Permits Registrations and Prohibitory Rules, stipulates KDAQ's construction and operating permit requirements. KDAQ administers the construction permits and operating permits through a "parallel review" process, which means that the construction and operating permit requirements for a Title V source are implemented and enforced through a single Title V permit.

The Project will be subject to 401 KAR 51:017 Prevention of Significant Deterioration of Air Quality as indicated by Table 2-1. 401 KAR 51:017 applies to the construction of a new major source or any project at an existing source that commences construction after September 22, 1982, and is located in an area designated attainment or unclassified under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii). According to 401 KAR 51:017, "The owner or operator of a new major stationary source or major modification, which is subject to the requirements of Sections 8 to 16 of this administrative regulation, shall not begin actual construction without a proposed permit or proposed permit revision issued under 401 KAR 52:020 stating that the major stationary source or major modification shall meet those requirements."

401 KAR 52:020, Title V Permits, already apply to the existing E.W. Brown Generating Station/Unit 3. Therefore, as required by KDAQ's "parallel review" process, this permit application is being submitted to comply with the requirements of 401 KAR 51:017 and 401 KAR 52:020, and KU is requesting a significant revision to the existing Title V permit for E.W. Brown Unit 3.

2.7.2.2 Kentucky – New Source Review Reform

The NSR program covers the construction of new major emitting facilities as well as existing facilities that make major modifications, which significantly increase emissions. The program requires that owners or new plants and existing plants planning major modifications obtain a permit before construction.

2.7.2.3 Chemical Accident Prevention

401 KAR 68, Chemical Accident Prevention, incorporates by reference federal 40 CFR Part 68, Accident Release Prevention Provisions.

The CAA added language to Section 112 that requires chemical accident prevention for affected facilities. Section 112(R), Prevention of Accidental Releases, establishes a general duty for owners and operators of stationary sources who produce, process, handle, or store any of a number of regulated substances to prevent and mitigate accidental releases of these substances by preparing detailed risk assessments and implementing a number of safety procedures through the preparation of a risk management plan (RMP).

The specific requirements of the RMP for affected facilities are established in 40 CFR Part 68, Accidental Release Prevention Provisions. These regulations require the owner/operator of an affected source to prepare and implement an RMP to detect and prevent/minimize accidental releases of regulated substances, and to provide a prompt emergency response to any such release in order to protect human health and the environment.

Affected facilities are those stationary sources that store, use, or handle any of 140 listed hazardous chemicals or flammable/explosive substances in greater than the listed threshold quantities. This list of regulated substances includes commonly stored liquid phases of gases such as ammonia, which the E.W. Brown currently stores at quantities above the threshold level. The plant will need additional storage for ammonia, which will be used, for the SCR.

The RMP is generally composed of three sections including a hazard assessment, a prevention program, and an emergency release response program. For affected facilities, submittal of the comprehensive RMP us required by the later of the following dates:

1. Three years after the date when a regulated substance is listed.
2. The date on which a regulated substance is first present above the threshold quantity at the facility.

The E.W. Brown Generating Station is already subject to the RMP since it currently uses and stores anhydrous ammonia in greater than the threshold quantities. The Project's SCR will use anhydrous ammonia. The RMP will be amended prior to the addition of anhydrous ammonia to the new SCR ammonia tanks.

3.0 Introduction and Executive Summary

As part of a consent decree between United States Environmental Protection Agency (USEPA) and Kentucky Utilities (KU), dated March 17, 2009, KU is required to install a selective catalytic reduction (SCR) to reduce NO_x emissions at Brown 3. The installation of this control equipment will coincidentally increase sulfuric acid mist (SAM or H_2SO_4) emissions above the 7 ton/yr significant emission rate threshold and will be classified as a New Source Review/Prevention of Significant Deterioration (NSR/PSD) major modification. As a result of the calculated emissions increase, the Project is subject to a Best Available Control Technology (BACT) review for sulfuric acid mist (H_2SO_4).

Brown 3 is a pulverized coal, tangentially fired boiler, combusting high-sulfur bituminous coal. It is equipped with cold-side dry ESP for particulate matter (PM) removal and wet FGD system for reduction of SO_2 in the flue gas. Future NO_x reduction utilizing selective catalytic reduction (SCR) is planned.

As required under the NSR/PSD regulations, the BACT analysis presented herein employed a "top-down," five-step analysis process to determine the appropriate emission control technologies and emissions limitations for the Project. The BACT analysis was conducted for the main boiler. The BACT analysis was conducted in accordance with the USEPA's recommended methodology:

- Step 1--Identify All Control Technologies.
- Step 2--Eliminate Technically Infeasible Options.
- Step 3--Rank Remaining Control Technologies by Control Effectiveness.
- Step 4--Evaluate Most Effective Controls.
- Step 5--Select BACT.

Step 1--Identify All Control Technologies

The first step in a "top-down" analysis is to identify all available control options for the emission unit in question. Identifying all the potential available control options consists of those air pollution control technologies or techniques with a practical potential for application to the emission unit and the regulated pollutant under evaluation. The potential available control technologies and techniques include lower emitting processes, practices, and post-combustion controls. Lower emitting practices can include fuel cleaning, treatment, or innovative fuel combustion techniques that are classified as pre-combustion controls. Post-combustion controls would be the various add-on controls for the pollutant being controlled.

Step 2--Eliminate Technically Infeasible Options

The second step of the "top-down" analysis is to identify the technical feasibility of the control options identified in Step 1, taking into account source-specific factors. A control option that is determined to be technically infeasible is eliminated. "Technically infeasible" is defined as a clearly documented case of a control option with technical difficulties precluding successful use of the control option because of physical, chemical, and engineering issues. After completion of this step, technically infeasible options are then eliminated from the BACT review process.

In Step 2, control options not eliminated are considered to be technically feasible. A "technically feasible" control option is defined as a control technology that has been installed and operated successfully at a similar type of source of comparable size to the proposed facility under review (i.e., "demonstrated"). If the control option cannot be demonstrated, the analysis considers two key concepts: availability and applicability. "Availability" is defined as technology that can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage/research and patenting) and testing stages (bench-scale/laboratory testing/pilot scale testing) are classified as not available. The second concept, "applicability," is defined as an available control option that can reasonably be installed and operated on the source type under consideration. In summary, the commercially available technology is applicable if it has been previously installed and operated at a similar type of source of comparable size, or a source with similar gas stream characteristics.

Step 3--Rank Remaining Control Technologies by Control Effectiveness

The third step of the "top-down" analysis is to rank all the remaining control alternatives not eliminated in Step 2, based on control effectiveness for the pollutant under review. If the BACT analysis proposes the top control alternative, it is not necessary to provide cost and other detailed information for other less effective control options.

Step 4--Evaluate Most Effective Controls

Once the control effectiveness is established in Step 3 for all the feasible control technologies identified in Step 2, additional evaluations of each technology are performed to make a BACT determination in Step 4. The impacts of the technology implementation on the viability of the control technology at the source are evaluated. The evaluation process of these impacts is also known as an impact analysis. The following impact analyses are performed for the remaining alternatives:

- Energy evaluation of alternatives.
- Environmental evaluation of alternatives.
- Economic evaluation of alternatives.

The first impact analysis addresses the energy evaluation of alternatives. The energy impact of each evaluated control technology is the energy penalty or benefit resulting from the operation of the control technology at the source. Direct energy impacts include such items as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance of the control technology in the flue gas flow path. The costs of these energy impacts are defined either in additional fuel costs or the cost of lost generation, which affects the cost-effectiveness of the control technology.

The second impact analysis addresses the environmental effects of alternatives. Non-air quality environmental effects are evaluated to determine the cost to mitigate the environmental effects caused by the operation of a control technology. Examples of non-air quality environmental effects include polluted water discharge and solids or waste generation. The procedure for conducting this analysis should be based on a consideration of site-specific circumstances.

The third and final impact analysis addresses the economic evaluation of alternatives. This analysis is performed to assess the cost to purchase and operate the control technology. The capital and operating/annual cost is estimated based on the established design parameters. Information for the design parameters is obtained from established reference sources. Documented assumptions can be made in the absence of available information for the design parameters. The estimated cost of control is represented as an annualized cost ($/year) and, with the estimated quantity of pollutant removed (tons/year), the cost-effectiveness ($/tons) of the control technology is determined. Cost-effectiveness is used to assess the economic cost to achieve the required emissions reduction in the most economical manner. Two types of cost-effectiveness are considered in a BACT analysis: average and incremental cost-effectiveness. Average cost-effectiveness is defined as the total annualized cost of control divided by the annual quantity of pollutant removed for each control technology. The incremental cost-effectiveness is a comparison of the cost and performance level of a control technology to the next most stringent option. It has a unit of (dollars/incremental ton removed). The incremental cost-effectiveness is a useful measure of economic viability when comparing technologies that have similar removal efficiencies.

Step 5--Select BACT

The highest ranked control technology that is not eliminated in Step 4 is proposed as BACT for the pollutant and emission unit under review.

As summarized in Table 3-1, the aforementioned BACT analysis process resulted in the following control technology and emissions level determinations for the Project's affected air emissions sources and pollutants.

Table 3-1
Brown 3 BACT Determination Summary

Pollutant	**Control Technology**	**Emission Basis**	**Compliance Method**
H_2SO_4	Wet FGD with Sorbent Injection	220 lb/hr	Initial Performance Test

3.1 BACT Analysis Basis

This section describes the basis of the BACT analysis, including the regulatory background, methodology and approach, and emission unit description and assumptions.

3.1.1 Regulatory Basis

The Clean Air Act Amendments of 1990 (CAA) established revised conditions for the approval of pre-construction permit applications under the PSD program. One of these requirements is that BACT be installed to control all pollutants regulated under the Act that are emitted in significant amounts from new major sources or major modifications.

The applicable state regulations governing this process can be found in Kentucky regulations 401 KAR 51:025, which states BACT as “Best available control technology" or "BACT" means an emissions limitation, including a visible emission standard, based on the maximum degree of reduction for each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification that:

(a) Is determined by the cabinet on a case-by-case basis after taking into account energy, environmental, and economic impacts and other costs, to be achievable by the source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of that pollutant;

(b) Does not result in emissions of a pollutant that would exceed the emissions allowed by an applicable standard of 40 C.F.R. Parts 60 and 61; and

(c) Is satisfied by a design, equipment, work practice, or operational standard or combination of standards approved by the cabinet, if, the cabinet determines technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, the standard establishes the emissions reduction achievable by implementation of the design, equipment, work practice or operation, and the standard provides for compliance by means that achieve equivalent results.

To bring consistency to the BACT process, states may use the USEPA’s “top-down” approach to BACT determinations, as discussed in USEPA guidelines. In practice, a top-down BACT analysis determines the most stringent control technology and emissions limitation combination available for a similar source or source category of emission units. At the head of the list in the top-down analysis are the control technologies and emissions limits that represent the Lowest Achievable Emission Rate (LAER) determinations, which, under NSR/PSD regulations, represent the most effective control alternative and must be considered under the BACT analysis process.

The following informational databases, clearinghouses, and documents were used to identify recent control technology determinations for similar source categories and emission units for this BACT analysis:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC).
- USEPA's National Coal Fired Utility Projects Spreadsheet (July 2007).
- Federal/State/Local new source review permits, permit applications, and associated inspection/test reports.
- Technical journals, newsletters, and reports.
- Information from air quality control (AQC) technology suppliers.
- Engineering design on other projects.

If the top level of control is feasible (for a similar type source and fuel category) and does not exhibit unacceptable economic, energy, or environmental effects, then that level of control must be declared to represent BACT for the respective pollutant and air emissions source. Alternatively, upon proper documentation that the top level of control is not feasible for a specific unit and pollutant based on a site- and/or project-specific consideration of the aforementioned screening criteria (e.g., technical, economic, energy, and environmental considerations), then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration. BACT cannot be determined to be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS) for the affected air emissions source.

3.1.2 Unit Operations and Baseline Emissions Basis

For coal fired boilers, reliable emission tests cannot be conducted during startup, shutdown, and malfunction to serve as a means of demonstrating compliance with an expressed BACT emission limit. This conclusion is consistent with the regulatory provisions of the NSPS, where the operations during periods of startup, shutdown, and malfunction are not considered representative for purposes of conducting compliance performance tests. BACT envisions these types of circumstances and provides for the use of applicable work practice standards such as good air pollution control practices and proper operation and maintenance as a basis for measurable and practicably enforceable compliance elements. However, recently EPA and the Kentucky Division for Air Quality (KDAQ) have held that BACT is applicable during all periods, including startup and shutdown. Additionally, KDAQ has made similar recommendations and have previously assigned lb/hr BACT emission limits for emission units undergoing NSR/PSD review. Therefore, should a H_2SO_4 BACT emission limit for startup and shutdown be determined to be applicable, this value should be based on a lb/hr rate consistent with previous determinations. Furthermore, the Brown 3 SCR will be designed for a wide range of operation and it likely will be in service at low loads. Thus, a lb/hr BACT limit is most appropriate.

Brown 3 is a base loaded electric generating unit and, for the purposes of this review, is designed to operate unrestricted for 8,760 hours per year with a planned capacity factor of 75%. The following subsections characterize the unit size, fuel, operating scenario, and emissions assumptions that were collectively utilized as a basis for the BACT analysis.

3.1.3 Coal Fired Boiler

Table 3-2 presents the BACT design basis for the Project's coal fired boiler.

Table 3-2
Main Boiler Design Basis[(a)]

Size	463 MW (gross) / 433 MW (net)
Maximum Heat Input	5,300 mmBtu/h[(b)]
Operating Hours	8,760 h/yr
Fuel	High-sulfur bituminous coal

[(a)] 100 percent load, average annual site conditions.
[(b)] Based upon firing design fuel.

Table 3-2 presents the typical high-sulfur bituminous coal quality fuel specifications which will be combusted by Brown 3. The fuel listed is considered representative of the design fuel proposed for this unit.

Table 3-3
Coal Fuel Specifications

Description	Value	High-Sulfur Bituminous
Higher Heating Value	Btu/lb_m	11,000
Ultimate Analysis		
Basis		As Received
Carbon	%	60.30
Hydrogen	%	4.50
Nitrogen	%	1.17
Sulfur	%	3.80
Chlorine	%	0.07
Ash	%	13.80
Moisture	%	9.56
Oxygen (by difference)	%	6.8

Using the design basis presented in Table 3-2 and the fuel specifications presented in Tables 3-3, the uncontrolled baseline emissions from Brown 3 for sulfuric acid mist are presented in Table 3-4.

Table 3-4
Brown 3 Baseline Uncontrolled H_2SO_4 Emissions[(a)]

Pollutant	Mass Rate (lb/h)
H_2SO_4	758

(a) Total emissions are based on typical, baseload fuel coal specifications at 5,300 mmBtu/h with future SCR in service.

3.2 Coal Fired Boiler Sulfuric Acid Mist BACT Analysis

This section presents the top-down, five-step BACT process used to evaluate and determine the H_2SO_4 emission limit for Brown 3. As this analysis will demonstrate, the proposed H_2SO_4 BACT limit for the Brown 3 is an emissions limit of 220 lb/hr.

3.2.1 Step 1--Identify All Control Technologies

The first step in a top-down analysis, according to the EPA's October 1990, Draft New Source Review Workshop Manual, is to identify all available control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emission unit and the sulfuric acid mist emission limit that is being evaluated. Sulfuric acid is present in the flue gases generated from the combustion of coal, because a small fraction of the SO_2 produced is further oxidized to SO_3. SO_3 reacts with water in the flue gas to form sulfuric acid vapor. Sulfuric acid can cause air heater fouling and equipment corrosion downstream, and when the flue gas containing sulfuric acid vapor is cooled, it condenses to form a submicron aerosol mist as it is emitted to the atmosphere.

In addition to the SO_3 formed during combustion, SCR catalysts used for NO_x control further oxidize a fraction of SO_2 to SO_3. The combination of furnace and SCR oxidation has the capability to produce significant quantities of SO_3. In addition, the SO_3 content in the furnace exit gas can limit SCR operation at lower unit loads because of the lower flue gas temperatures that result from the low load operation. The potential to form ammonium sulfate salts that will foul active catalyst sites increases at the lower economizer outlet flue gas temperatures.

Effective controls for H_2SO_4 include only post-combustion controls and include lime-based semi-dry FGDs, wet FGDs, wet ESPs, and alkali sorbent injection systems. These control technology alternatives are described below.

3.2.2 Lime-Based Semi-Dry FGD Systems

US utilities have installed numerous semi-dry FGD systems on some boilers using lower sulfur fuels such as lignite or subbituminous coals. While this FGD system is installed for SO_2 removal from flue gas, a co-benefit of the semi-dry FGD system is the high removal of SO_3. In fact, semi-dry FGD in combination with fabric filters have been determined as a BACT type technology for SO_3 removal.

The SO_3 removal is made possible because the flue gas temperature leaving a lime-based semi-dry FGD is lowered below the sulfuric acid dew point, and significant SO_3 removal is attained as the condensed acid reacts with the alkaline lime-based reagent in the fabric filter cake.

3.2.3 Wet FGD

Similar to the semi-dry FGD system, the wet FGD is capable of incremental removal (low removal rates) of SO_3 from the flue gas as a co-benefit to the primary controlled pollutant, which is SO_2. SO_3 reduction is achieved via two primary mechanisms.

The first method is by removing SO_3 that is condensed on the fly ash surface as the flue gas enters the FGD absorber and is quenched by the limestone slurry spray. This removal method is dependent on the particulate removal capability of the wet FGD system, which is also an incremental type co-benefit. Additionally, the wet FGD is typically installed downstream of the primary particulate collection device; therefore, the fly ash concentration in the flue gas will be very low.

The second mechanism for SO_3 removal from the flue gas is by contacting the SO_3 molecules with the limestone slurry spray droplets, absorbing the SO_3 molecules into the droplets, and neutralization of the acidic SO_3 by the alkaline limestone-based slurry. However, this removal mechanism is not very effective because the contact process between the SO_3 molecules and limestone slurry spray droplets cannot be achieved efficiently. The SO_3 molecules are very small when compared to the spray droplets, so the fluid dynamics interaction will result in the smaller SO_3 particle circumventing the large spray droplet when both particles collide from opposite directions. It should be noted that the efficiency of SO_3 contact with the spray droplet varies between the wet FGD designs available because of the different limestone spray philosophies.

3.2.4 Wet Electrostatic Precipitator

On the very few wet ESP (WESP) control systems installed on utility boilers, they are typically installed downstream of a wet FGD. In high-sulfur coal applications, the addition of a WESP allows sulfuric acid mist to condense and be collected as particulate or absorbed into the water stream along the charged collection surfaces.

A WESP collects particles based on the same principle as a dry ESP; negatively charged particles are collected on positively charged surfaces. However, the main difference in WESP operations is that the collecting surfaces are wet instead of dry and are flushed with water rather than being rapped to remove the particulate. Typically, a WESP is installed downstream of an existing wet FGD system, where the flue gas is already saturated, so the amount of added water is minimized. The particulate collection efficiency is enhanced by a lack of re-entrainment after contact with the wet collector plates (as contrasted with re-entrainment during rapping on a dry ESP). Therefore, a WESP is well suited for fine particulate or acid mist applications because it reduces opacity, sulfuric acid mist, and other aerosols.

However, a WESP is not well suited as the primary particulate control device for handling uncontrolled particulate emissions levels from the boiler. The large amount of sludge wastewater produced for capturing the large amount of particulate material would not be technically feasible.

The use of a WESP for acid mist collection was one of the earliest applications for ESP. Although there are relatively few applications in the utility industry, this is a mature technology with hundreds of industrial installations, though the scale of most of those is dramatically different.

3.2.5 Sorbent Injection Systems

Injection of finely divided alkalis into the flue gas has been demonstrated for the removal of SO_3 from flue gases. Most commercial experience is from units firing high sulfur oil where trace metals, mainly vanadium, increase SO_2 oxidation. Magnesium-based compounds have been used successfully for decades to capture SO_3 in oil fired units. As coal fired units burning high sulfur bituminous coals have been retrofitted with SCR systems (primarily in the east), interest in the injection of alkali compounds directly into the flue gas duct of a unit has increased. Sorbents such as sodium bisulfite, trona, and hydrated lime have recently been tested on large coal fired units, with reported results showing the achievement of high control efficiencies of SO_3 in high sulfur applications. The alkaline material injected can be classified to magnesium-, sodium-, and calcium- based sorbents. The injection points for the reagents may vary in the flue gas flow path, from in-furnace, upstream of air heater, upstream of dry ESP, and upstream of wet FGD.

3.2.6 Step 2--Eliminate Technically Infeasible Options

Step 2 of the BACT analysis involves the evaluation of all the identified available control technologies in Step 1 of the BACT analysis to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source of comparable size, or there is technical agreement that the technology can be applied to the source. Available and applicable are the two terms used to define the technical feasibility of a control technology.

From a review of the aforementioned H_2SO_4 control technologies, it can be concluded that all of the aforementioned four technologies (i.e., dry FGD, wet FGD, sorbent injection systems, and WESP) are technically feasible as H_2SO_4 control technology alternatives for Brown 3. Table 3-5 summarizes the evaluation of the technically feasible H_2SO_4 options. However, a wet FGD is currently being retrofitted at

Brown 3 and, therefore, a wet FGD with sorbent injection and the WESP will be considered further in the BACT analysis.

Table 3-5
Summary of Step 2--Eliminate Technically Infeasible Options

	Technically Feasible (Yes/No)	
Technology Alternative	Available	Applicable
Dry (or semi-dry) FGD	Yes	No
Wet FGD	Yes	Yes
Sorbent Injection with Wet FGD	Yes	Yes
Wet ESP with Wet FGD	Yes	Yes

3.2.7 Step 3--Rank Remaining Control Technologies by Effectiveness

A review of the information contained in the USEPA BACT/LAER Clearinghouse and other sources specified in Section 3.2.1 was conducted to determine the top level of H_2SO_4 control for pulverized coal boilers. A search was also conducted for recently permitted coal fired facilities whose BACT determinations have not yet been included in the current BACT/LAER Clearinghouse database, but no additional facilities were identified. The results of this search for all coal fired boilers are listed in Attachment A. Table 3-6 shows the H_2SO_4 BACT determinations (proposed and proposed limits) that have the closest attributes when compared to Brown 3, which include fuel type, boiler technology, and boiler size.

Table 3-6

H_2SO_4 Top-Down RBLC Clearinghouse Review Results

FACILITY	COMPANY	STATE	FUEL	SIZE (MW)	BOILER TECH.	LIMIT (lb/mmBtu)	LIMIT (lb/hr)	CONTROL TECH.	PERMIT STATUS	OPERATIONAL STATUS	COMPLIANCE METHOD
SANTEE COOPER CROSS GENERATING STATION UNITS 3 & 4	SANTEE COOPER	SC	Bituminous	2X660	PC	0.0014	$7.98^{(b)}$	WFGD	Permit issued	Unit 3 in 2007 Unit 4 in 2008	Initial Performance Test
TRIMBLE COUNTY GENERATINIG STATION UNIT 2	LOUISVILLE GAS & ELECTRIC COMPANY	KY	Subbituminous/ Bituminous Blend	750	PC	0.0038	$26.6^{(a)}$	WESP	Permit Issued	Under Construction	Initial Performance Test
ELK RUN ENERGY STATION	LS POWER DEVELOPMENT	IA	Subbituminous/ Bituminous Blend	750	PC	$0.0034+Z78^{(d)}$	$24.9^{(b)}$	DFGD/FF	Proposed	Cancelled (2009)	–
CLIFFSIDE	DUKE POWER	NC	Subbituminous/ Bituminous Blend	2x800	PC	$0.005^{(e)}$	$39.3^{(b)}$	WFGD	Proposed	One unit rejected; Unit 6 under construction	Annual testing
MAIDSVILLE	LONGVIEW POWER. LLC	WV	Bituminous	600	PC	0.0075	$45.8^{(a)}$	WFGD/Inj/FF	Permit issued	Under Construction	Initial Performance Test & Testing Every 5 Years
PEE DEE GENERATING STATION	SANTEE COOPER	SC	Bituminous/Pet Coke	2X660	PC	$0.005^{(c)}$	$28.5^{(b)}$	WFGD	Proposed	Under Construction	Initial Performance Test
AMERICAN MUNICIPAL POWER OHIO GENERATING STATION	AMP-OHIO	OH	Subbituminous/ Bituminous Blend	2x480	PC	0.0075	$38.9^{(a)}$	WFGD	Proposed	Permitting	Initial Performance Test
ELM ROAD GENERATING STATION (EXISTING OAK CREEK FACILITY) UNITS 1 & 2	WISCONSIN ENERGY	WI	Subbituminous	2X615	PC	0.0100	$61.8^{(a)}$	WFGD	Permit Issued	Under Construction	IPT + every 60 months + parametric
PRAIRIE STATE GENERATING STATION	PEABODY	IL	Bituminous	2X750	PC	$0.039^{(f)}$	$37.1^{(a)}$	WFGD	Permit issued - under appeal	Under Construction	Initial Performance Test
INTERMOUNTAIN POWER GENERATING STATION UNIT 3	INTERMOUNTAIN POWER SERVICE	UT	Bituminous/Blend	950	PC	0.0044	$39.82^{(b)}$	WFGD	Permit Issued	Cancelled (2007)	Annual Test
COMANCHE STATION UNIT 3	PUBLIC SERVICE COMPANY OF COLORADO	CO	Sub-Bituminous	750	PC	0.0042	$31.17^{(b)}$	Lime SD+FF	Permit Issued	Under Construction	3, 1-hr test runs
OPPD-NEBRASKA CITY STATION UNIT 2	OMAHA PUBLIC POWER DISTRICT	NE	Sub-Bituminous	660	PC	0.0042	$27.21^{(b)}$	DFGD+FF	Permit Issued	Under Construction	Test method average

(a) Value indicated in air permit.
(b) Calculated value based on the stated emission level and boiler heat input rate
(c) RBLC previously indicated 0 0075 lb/MBtu, but permit # 1040-0113-CA indicated 0 005 lb/MBtu
(d) RBLC previously indicated 0 0042, but draft permit indicated 0.0034 lb/Mbtu
(e) RBLC previously indicated 0 006. but draft permit indicated 0.005 lb/Mbtu
(f) Permit indicates 0 005 lb/Mbtu. but RBLC indicates 0 0390 lb/Mbtu

A review of the H_2SO_4 BACT determinations in Table 3-6 indicates the following information for new facilities; however, no information was identified for facilities undergoing a retrofit:

- The lowest H_2SO_4 emission limit **permitted** for a new high-sulfur bituminous fueled PC boiler is 0.0014 lb/mmBtu, utilizing a Wet FGD at the Santee Cooper Cross Generating Station.
- The lowest H_2SO_4 emission limit **permitted** for a new high-sulfur bituminous fueled PC boiler utilizing WESP is 0.0038 lb/mmBtu at the Louisville Gas & Electric Trimble County Generating Station.
- The lowest H_2SO_4 emission limit **permitted** for a new high-sulfur bituminous fueled PC boiler is 0.0042 lb/mmBtu, utilizing a Dry FGD and Fabric Filter at the LS Power Elk Run Energy Station.
- The most stringent H_2SO_4 emission limit **permitted** for a new high-sulfur bituminous fueled PC boiler utilizing Wet FGD with sorbent injection is 0.0075 lb/mmBtu at the Longview Power Maidsville project.
- Several H_2SO_4 emissions limits that are being **proposed and permitted** between 0.010 and 0.039 lb/mmBtu for new high-sulfur bituminous fueled PC units utilizing Wet FGD, including Wisconsin Energy Elm Road Generating Station at 0.010 lb/mmBtu, Sempra Generation Twin Oaks

Power Plant at 0.020 lb/mmBtu, and Peabody Prairie State Generating Station at 0.039 lb/mmBtu.

- Compliance for these facilities is based on emissions testing. The noted facility list does not contain retrofit designs.

The wide range of H_2SO_4 emission limits proposed for high-sulfur bituminous and blends of high-sulfur bituminous with other fuels in PC boilers (as shown in Attachment A) is, in large part, due to the fact that the emission reductions proposed are actually the result of an assumed collateral control benefit from control technologies used to limit emissions of SO_2 and PM/PM_{10}, and the variability in the assumed SO_2 to SO_3 conversion and fuel sulfur content. These aforementioned sources are new units which are designed to efficiently combined emission control technology to achieve combined control of H_2SO_4 emissions. However, Brown 3 is an existing unit being retrofitted as a result of a consent decree. Additionally, there is little to no information available for a new or retrofitted existing unit which demonstrates continuous long-term compliance with the H_2SO_4 BACT determination emission limits proposed and summarized above.

While the review of the H_2SO_4 BACT determinations indicated several projects with low permitted levels of H_2SO_4 for high-sulfur bituminous fueled PC boiler utilizing Wet FGD with sorbent injection (in some cases) it should be noted that these are new projects that have been designed for optimal reduction of H_2SO_4 using sorbent injection and particulate matter collection systems that accounts for the additional PM loading from the H_2SO_4 mitigation system. Therefore, the evaluation of the control effectiveness for Brown 3 has to take into consideration, additional factors that impact the level of H_2SO_4 control achievable.

3.2.8 Wet FGD with Sorbent Injection

One of these additional factors that can affect the level of achievable control is the additional PM loading due to sorbent injection rates. For Brown 3, the consent decree requires a controlled PM level of 0.03 lb/mmBtu (on a 6-hour and 24-hour rolling basis), which is achieved using the cold-side ESP and Wet FGD system. The use of sorbent injection for Brown 3 must take into consideration the design PM loading and removal capacity of the cold-side ESP and Wet FGD. The sorbent injection rate will be ultimately limited by the PM emissions level at the stack.

For the sorbent injection systems, KU has recently performed testing of a sorbent injection system at Ghent Unit 3, which has a similar back-end air quality control configuration (except for hot-side ESP versus cold-side ESP) as Brown 3. Trona injection was utilized at Ghent 3 because of its hot-side ESP arrangement, and Trona has been demonstrated for injection upstream of both the hot-side and cold-side ESP. Opacity measurements were also recorded during this test to continually evaluate the impacts of sorbent injection on the particulate matter emission level. From the test results, it can be seen that opacity levels below 20% were maintained for injection rates up to 3,000 lb/hr. Therefore, it is expected that the test results achieved at Ghent 3 will be representative of a similar injection scenario and the resulting H_2SO_4 emissions achieved, if applied at Brown 3. A summary of the test results for Ghent 3 are presented in Attachment B.

Applying similar level of control as demonstrated in the Ghent 3 test results to Brown 3, the expected control effectiveness of the sorbent injection system (limited by PM emission limit) is 0.042 lb/mmBtu. Correspondingly, this equates to an emission rate of 220 lb/hr. The calculation process to determine the emission rates is presented in Attachment C.

3.2.9 WESP

For the WESP system, high levels of H_2SO_4 reduction can be achieved due to the moisture saturated operating condition and high conductivity of the H_2SO_4 mist particles. For a retrofit scenario, the WESP is expected to remove H_2SO_4 to levels comparable to new units that were reviewed in Section 3.3.3.

3.2.10 Ranking of H_2SO_4 Control Technology

Based upon the technologies identified as technically feasible and available in Steps 1 and 2, the following technologies presented in Table 3-7 are ranked in a "Top-Down Approach" methodology.

Table 3-7
Ranking of H_2SO_4 Control Technologies

Control Option	Control Effectiveness (lb/mmBtu)
Wet ESP with Wet FGD	0.004
Sorbent Injection with Wet FGD	0.042

3.2.11 Step 4--Evaluate Most Effective Controls and Document Results

In the following subsections, the technically feasible control alternatives are evaluated in a comparative approach with respect to their energy, environmental, and economic impacts on the Project.

3.2.12 Energy Evaluation of Alternatives

While the energy impact of a WESP is considerably greater than that of sorbent injection, there are no significant energy impacts that would preclude the use of these technologies to limit H_2SO_4.

3.2.13 Environmental Evaluation of Alternatives

When considering any WESP technology, there are potential environmental impacts associated with the direct operation of the technology. In general, the impacts are consistent with that of a wet FGD, which is the creation of a visible stack plume, increased water consumption, and the requirements of a wastewater treatment system. However, since a WESP is typically located after a wet FGD, its environmental impacts are essentially shared.

As discussed in Section 3.3.8, the sorbent injection systems has a potential impact on the PM emission limit, but the increase in the PM emission level will be mitigated by the cold-side ESP and Wet FGD and a controlled sorbent injection rate for H_2SO_4 control.

3.2.14 Economic Evaluation of Alternatives

The economic evaluations of the WESP and sorbent injection control alternatives have been assessed in this BACT analysis and are presented in Section 3.3.15.

Tables 3-8 and 3-9 present the total capital investment for the installation of a WESP or sorbent injection system at Brown 3, respectively. As described in the tables, the purchased equipment costs include the respective sulfuric acid mist control technologies. The direct installation costs, which include balance-of-plant items such as foundations and supports, handling and erection, electrical, piping, insulation, and paint, were calculated as a percentage of the purchased equipment costs and totaled with the purchased equipment costs to estimate the total direct costs of each control alternative. Finally, the total capital investment was calculated as the summation of the total direct costs and total indirect costs (including engineering and owner's costs) and an allowance for funds used during construction.

Tables 3-8 and 3-9 also present the annualized operating costs for the installation of a wet ESP or sorbent injection system on the Project's main boiler. As described in the tables, the operating fixed and variable direct annual costs includes operating labor, maintenance labor and materials, and auxiliary and ID fan power costs. The indirect annual costs, which includes, the capital recovery costs, is totaled with the direct annual costs to estimate the total annual costs for the control system.

3.2.15 Step 5--Select H_2SO_4 BACT

The development of an emissions limit (and eventual compliance) has to be carefully considered and estimated on the basis of assumptions relative to fuel sulfur content (refer to Table 3-3), SO_2 to SO_3 conversion during the combustion process and across the SCR. The following assumptions form the basis for the H_2SO_4 BACT limitation for the proposed control technology:

- Oxidation conversion of a total of 2.0 percent of SO_2 to SO_3 in the combustion process and across the SCR catalyst.
- Fuel sulfur as presented in the BACT basis, Table 3-3.

Tables 3-8 and 3-9 provide the economic analysis for installation of the wet ESP and sorbent injection technology, respectively. Table 3-10 summarizes the top-down evaluation of the sulfuric acid mist BACT control alternatives, including economic, energy, and environmental considerations, in accordance with the BACT determination methodology previously discussed. Table 3-11 summarizes the Project's H_2SO_4 BACT determination for Brown 3.

KU has determined that a sorbent injection system, in combination with a wet FGD, represents the H_2SO_4 BACT for Brown 3. The decision to select sorbent injection is based on the control technology with a reasonable annualized cost and control effectiveness. This is also the top control technology evident in recent permits for similar sized units and fuels such as the Longview Power Maidsville project and the technology is more easily installed at an existing unit than other control options. Therefore, a sulfuric acid mist limit of 220 lb/hr is proposed as BACT for Brown 3. The emission limit of 220 lbs/hr corresponds to approximately 71 percent removal of H_2SO_4 for the sorbent injection system when firing the design basis fuel. The total reduction removal efficiency from uncontrolled SO_3 emissions is approximately 84 percent. These emission calculations, which are based on the Controlled Condensate Test Method, are shown in Attachment C of Section 3.

Table 3-8
Wet ESP Equipment Engineering Analysis - Cost Analysis (WESP)

Kentucky Utilities E.W. Brown H2SO4 BACT Analysis - Cost Estimate

Technology: Brown 3 - Wet ESP

Date: 6/12/2009

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
WESP system includes casing, electrical sys., penthouse blower & heater, access provisions	$29,900,000	Engineering estimate			
Ash handling system	$1,370,000	Engineering estimate			
Booster fans	$1,790,000	Engineering estimate			
Electrical system upgrades	$1,790,000	Engineering estimate			
Ductwork	$4,110,000	Engineering estimate			
Subtotal capital cost (CC)	$38,960,000				
Instrumentation and controls	$1,948,000	(CC) X	5.0%		
Freight	$974,000	(CC) X	2.5%		
Total purchased equipment cost (PEC)	$41,882,000				
Direct installation costs					
Foundation & supports	$8,376,000	(PEC) X	20.0%		
Handling & erection	$20,941,000	(PEC) X	50.0%		
Electrical	$4,188,000	(PEC) X	10.0%		
Piping	$2,094,000	(PEC) X	5.0%		
Insulation	$838,000	(PEC) X	2.0%		
Painting	$419,000	(PEC) X	1.0%		
Demolition	$419,000	(PEC) X	1.0%		
Relocation	$419,000	(PEC) X	1.0%		
Total direct installation costs (DIC)	$37,694,000				
Site preparation	$250,000	Engineering estimate			
Buildings	$0	N/A			
Total direct costs (DC) = (PEC) + (DIC)	$79,826,000				
Indirect Costs					
Engineering	$9,579,000	(DC) X	12.0%		
Owner's cost	$6,386,000	(DC) X	8.0%		
Construction management	$7,983,000	(DC) X	10.0%		
Start-up and spare parts	$1,197,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$15,965,000	(DC) X	20.0%		
Total indirect costs (IC)	$41,210,000				
Allowance for Funds Used During Construction (AFDC)	$8,424,000	[(DC)+(IC)] 4.64%		3 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$129,460,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance materials and labor	$2,395,000	(DC) X	3.0%		
Operating labor	$110,000		1 FTE and	110,000 $/year	Estimated manpower
Total fixed annual costs	$2,505,000				
Variable annual costs				75 %	capacity factor
Reagent [$Mg(OH)_2$]	$30,000		44 lb/hr and	210.00 $/ton	estimated
Auxiliary power	$362,000		1,636 kW and	0.03364 $/kWh	estimated
ID fan power	$539,000		2,441 kW and	0.03364 $/kWh	estimated
Service water	$245,000		207 gpm and	3 $/kgal	estimated
Total variable annual costs	$1,176,000				
Total direct annual costs (DAC)	$3,681,000				
Indirect Annual Costs					
Cost for capital recovery	$15,846,000	(TCI) X	12.24%	CRF	
Total indirect annual costs (IDAC)	$15,846,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$19,527,000**				

Table 3-9
SO_3 Sorbent Injection Equipment Engineering Analysis - Cost Analysis
(SO_3 Sorbent Injection)

Technology: Brown 3 - Sorbent Injection

Date: 5/19/2009

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
Long-term storage silo (with truck unloading sys.)	$350,000	Engineering estimate		
Short-term storage silo	$230,000	Engineering estimate		
Air blowers	$320,000	Engineering estimate		
Rotary feeders	$40,000	Engineering estimate		
Injection system	$150,000	Engineering estimate		
Ductwork modifications, supports, platforms	$30,000	Engineering estimate		
Electrical system upgrades	$960,000	Engineering estimate		
Instrumentation and controls	$50,000	Engineering estimate		
Subtotal capital cost (CC)	$2,130,000			
Freight	$53,000	(CC) X 2.5%		
Total purchased equipment cost (PEC)	$2,183,000			
Direct installation costs				
Foundation & supports	$218,000	(PEC) X 10.0%		
Handling & erection	$437,000	(PEC) X 20.0%		
Electrical	$218,000	(PEC) X 10.0%		
Piping	$109,000	(PEC) X 5.0%		
Insulation	$44,000	(PEC) X 2.0%		
Painting	$109,000	(PEC) X 5.0%		
Demolition	$0	(PEC) X 0.0%		
Relocation	$0	(PEC) X 0.0%		
Total direct installation costs (DIC)	$1,135,000			
Site preparation	$0	N/A		
Buildings	$75,000	Engineering estimate		
Total direct costs (DC) = (PEC) + (DIC)	$3,393,000			
Indirect Costs				
Engineering	$407,000	(DC) X 12.0%		
Owner's cost	$407,000	(DC) X 12.0%		
Construction management	$339,000	(DC) X 10.0%		
Start-up and spare parts	$51,000	(DC) X 1.5%		
Performance test	$100,000	Engineering estimate		
Contingencies	$679,000	(DC) X 20.0%		
Total indirect costs (IC)	$1,983,000			
Allowance for Funds Used During Construction (AFDC)	$125,000	[(DC)+(IC)] 4.64%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$5,501,000**			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Maintenance labor and materials	$102,000	(DC) X 3.0%		
Operating labor	$110,000	1 FTE and	110,000 $/year	Estimated manpower
Total fixed annual costs	$212,000			
Variable annual costs			75 %	capacity factor
Sorbent (trona)	$1,183,000	3,000 lb/hr and	120 $/ton	from Ghent 3 testing
Auxiliary power	$35,000	160 kW and	0.03364 $/kWh	estimated
Total variable annual costs	$1,218,000			
Total direct annual costs (DAC)	$1,430,000			
Indirect Annual Costs				
Cost for capital recovery	$673,000	(TCI) X 12.24%	CRF	
Total indirect annual costs (IDAC)	$673,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$2,103,000**			

Table 3-10
Sulfuric Acid Mist
Top-Down BACT Summary

	Emissions		Economic Impacts				Energy Impacts	Environmental Impacts	
Control Alternative	Emissions, lb/h	Emissions Reduction, tpy	Total Capital Cost, \$1,000	Total Annualized Cost, \$1,000/yr	Control Cost-Effectiveness, \$/ton	Incremental Cost-Effectiveness, \$/ ton	Incremental Increase Over Baseline, kWh/yr	Toxic Impacts (Yes/No)	Adverse Environmental Impacts (Yes/No)
Sorbent Injection with Wet FGD	220	1,767	5,501	2,103	1,190	--	1,051,200	No	No
Wet ESP with Wet FGD (0.004 lb/mmBtu)	21.2	2,420	129,460	19,527	8,068	26,683	26,785,892	No	No
Uncontrolled Base Line (with Wet FGD)	758	--	--	--	--	--	--	--	--

Table 3-11
Brown 3 H_2SO_4 BACT Determination

Control Technology	Emission Limit (lb/hr)
Sorbent Injection with Wet FGD	220(a)

(a)Is equivalent to a sulfuric acid mist rate of 0.042 lb/mmBtu (based on the Controlled Condensate Test Method) and a concentration of 10 ppmvw at actual O_2 conditions.

Attachment A
Coal Fired Boiler Top-Down RBLC Clearinghouse Review Results

H2SO4 Top Down RBLC Clearinghouse Technology Review Results

FACILITY	COMPANY	STATE	FUEL	SIZE (MW)	BOILER TECHNOLOGY	LIMIT (lb/mmBtu)	AVERAGING PERIOD	CONTROL TECHNOLOGY	STATUS	NSR BASIS	DATA SOURCE
SANTEE COOPER CROSS GENERATING STATION	SANTEE COOPER	SC	Bituminous	2X660	PC	0.0014		WFGD	Permit issued	PSD Avoidance/Net Out PSD	RBLC
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	CITY UTILITIES OF SPRINGFIELD	MO	Subbituminous	275	PC	0.00018		DFGD	Permit issued	BACT-PSD	Reg Spreadsheet
SEVIER POWER COMPANY	NEVCO - SEVIER POWER COMPANY	UT	Subbituminous	270	CFB	0.0024	24-Hr	Lime Scrubber	Permit issued	BACT-PSD	RBLC
BEECH HOLLOW POWER PROJECT	ROBINSON POWER COMPANY LLC	PA	Waste Coal	272	CFB	0.0030		Limestoned Inj.	Permit issued - under appeal	BACT-PSD	RBLC
CALAVERAS LAKE STATION (J K SPRUCE)	CITY PUBLIC SERVICE OF SAN ANTONIO	TX	Subbituminous	750	PC	0.0037		WFGD	Permit issued	BACT-PSD	Reg Spreadsheet
HUGO STATION	WESTERN FARMERS ELECTRIC COOP	OK	Subbituminous	750	PC	0.0037		DFGD	Permit issued	BACT-PSD	Reg Spreadsheet
SANDY CREEK ENERGY STATION	SANDY CREEK ENERGY ASSOCIATES	TX	Subbituminous	800	PC	0.0037		DFGD/FF	Permit issued	BACT-PSD	RBLC/Reg Spreadsheet
MUTIPLE GENERATING STATIONS	TXU	TX		800	PC	0.0037		WFGD	Proposed	BACT-PSD	Reg Spreadsheet
NORBORNE POWER PLANT	ASSOCIATED ELECTRIC CO-OPERATIVE INC	MO	Subbituminous	781	PC	0.0038		DFGD/FF	Permit Issued	BACT-PSD	Draft Permit
TRIMBLE COUNTY GENERATINIG STATION	LOUISVILLE GAS & ELECTRIC COMPANY	KY	Subbituminous/Bituminous Blend	750	PC	0.0038	3-Hr (26.6 lb/h)	WESP	Permit Issued	BACT-PSD	Reg Spreadsheet
GLADES POWER PARK	FLORIDA POWER & LIGHT COMPANY	FL	Bituminous/Pet Coke	2X980	PC	0.0040		WFGD	Withdrawn	BACT-PSD	Reg Spreadsheet
HOLCOMB POWER PLANT	SUNFLOWER ELECTRIC POWER	KS	PRB	3x700	PC	0.0040		DFGD/FF	Draft Permit	BACT-PSD	Reg Spreadsheet
SOUTH HEART POWER PROJECT	GREAT NORTHERN POWER DEVELOPMENT	ND	Lignite	500	CFB	0.0042		Limestone Inj and Polishing Dry Scrubber	Proposed	BACT-PSD	Reg Spreadsheet
OPPD - NEBRASKA CITY STATION	OMAHA PUBLIC POWER DISTRICT	NE	Subbituminous	660	PC	0.0042		DFGD/FF	Permit issued	BACT-PSD	RBLC
MIDAMERICAN ENERGY COMPANY	MIDAMERICAN ENERGY COMPANY	IA	PRB	790	PC	0.0042		DFGD	Permit issued	BACT-PSD	RBLC
COMANCHE STATION (UNIT 3)	XCEL ENERGY	CO	Subbituminous	750	PC	0.0042		DFGD	Permit issued	Net Out-PSD	Reg Spreadsheet
ELK RUN ENERGY STATION	LS POWER DEVELOPMENT	IA	Subbituminous/Bituminous Blend	750	PC	0.0042	3-Hr	DFGD/FF	Proposed	BACT-PSD	Draft Application
TS POWER PLANT	NEWMONT NEVADA ENERGY INVESTMENT, LLC	NV	PRB	200	PC	0.0043		DFGD/FF	Permit issued	BACT-PSD	RBLC
INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	INTERMOUNTAIN POWER SERVICE CORPORATION	UT	Subbituminous/Bituminous Blend	900	PC	0.0044	24-Hr	WFGD/FF	Permit issued	BACT-PSD	RBLC
MANITOWOC PUBLIC UTILITIES	MANITOWOC PUBLIC UTILITIES	WI	Coal/Pet Coke	64	CFB	0.0045		Limestone Inj.	Permit issued	N/A	RBLC
THOROUGHBRED GENERATING STATION	GENERATING COMPANY, LLC (PEABODY)	KY	Bituminous	2X750	PC	0.00497		WFGD	Permit issued	BACT-PSD	RBLC
BONANZA	DESERET GENERATION & TRANSMISSION	UT	Waste Coal	110	CFB	0.0050		Limestone Inj and Polishing Dry Scrubber	Proposed	Net Out-PSD	Reg Spreadsheet
WPS - WESTON PLANT (UNIT 4)	WISCONSIN PUBLIC SERVICE	WI	PRB	500	PC	0.0050	24-Hr	DFGD	Permit issued	BACT-PSD	RBLC/Reg Spreadsheet

H2SO4 Top Down RBLC Clearinghouse Techonology Review Results

FACILITY	COMPANY	STATE	FUEL	SIZE (MW)	BOILER TECHNOLOGY	LIMIT (lb/mmBtu)	AVERAGING PERIOD	CONTROL TECHNOLOGY	STATUS	NSR BASIS	DATA SOURCE
LONGLEAF ENERGY ASSOCIATES	LS POWER DEVELOPMENT	GA	Subbituminous/Bituminous Blend	2x600	PC	0.0050	30-Day	DFGD	Permit issued	BACT-PSD	Reg Spreadsheet
ESTILL COUNTY ENERGY PARTNERS	ESTILL COUNTY ENERGY PARTNERS	KY	Bituminous	110	CFB	0.0050	30-Day	Limestone Inj and Polishing Dry Scrubber	Proposed	BACT-PSD	Reg Spreadsheet
EAST KENTUCKY POWER COOP., INC./SPURLOCK POWER STA (Unit 4)	EAST KENTUCKY POWER COOP., INC.	KY	Bituminous	300	CFB	0.0050	3-Hr	Limestone Inj and Polishing Dry Scrubber	Draft Permit	BACT-PSD	Reg Spreadsheet
EAST KENTUCKY POWER COOP., INC./SPURLOCK POWER STA (UNIT 3)	EAST KENTUCKY POWER COOP., INC.	KY	Bituminous	270	CFB	0.0050	30-Day	Limestone Inj and Polishing Dry Scrubber	Permit issued	BACT-PSD	RBLC
OTTER TAIL POWER COMPANY	OTTER TAIL POWER COMPANY	SD	Subbituminous	600	PC	0.0050		WFGD	Proposed	Net Out-PSD	Reg Spreadsheet
HIGHWOOD GENERATING STATION	SOUTHERN MONTANA ELECTRIC GENERATION & TRANSMISSION COOP	MT	Subbituminous	270	CFB	0.0054	1-Hr	Limestone Inj	Proposed	BACT-PSD	Reg Spreadsheet
FORMOSA	FORMOSA PLASTICS CORP	TX	Subbituminous/Pet Coke	2X150	CFB	0.0055		Limestone Inj	Proposed	BACT-PSD	Reg Spreadsheet
OAK GROVE (UNITS 1 & 2)	TXU	TX	Lignite	2x800	PC	0.0055		WFGD	Proposed	BACT-PSD	Reg Spreadsheet
SWEPCO UNIT	AMERICAN ELECTRIC POWER (AEP)	AR	PRB	600	PC	0.0060		DFGD	Proposed	BACT-PSD	Reg Spreadsheet
WESTERN GREENBRIER CO-GENERATION, LLC	WESTERN GREENBRIER CO-GENERATION, LLC	WV	Waste Coal	98	CFB	0.0060		Limestone Inj/FF	Permit issued - under appeal	BACT-PSD	RBLC/Reg Spreadsheet
GREENE ENERGY RESOURCE RECOVERY PROJECT	WELLINGTON DEV/GREENE ENERGY	PA	Waste Coal	2X250	CFB	0.0060		Limestone Inj and Polishing Scrubber	Permit issued - under appeal	BACT-PSD	RBLC
CLIFFSIDE	DUKE POWER	NC	Subbituminous/Bituminous Blend	2x800	PC	0.0060	3-Hr	WFGD	Proposed	Net Out-PSD	Reg Spreadsheet
GASCOYNE GENERATING STATION	MONTANA DAKOTA UTILITIES / WESTMORELAND POWER	ND	Lignite	175	CFB	0.0061	3-Hr	Limestone Inj	Permit issued	BACT-PSD	RBLC
PLUM POINT ENERGY	PLUM POINT ASSOCIATES, LLC	AR	Subbituminous	800	PC	0.0061		DFGD/FF	Permit issued	BACT-PSD	RBLC
HARDIN GENERATOR PROJECT	ROCKY MOUNTAIN POWER, INC.	MT	Subbituminous	116	PC	0.0063	1-Hr	DFGD	Permit issued	Other Case-by-Case	RBLC/Reg Spreadsheet
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	BULL MOUNTAIN DEV. COMPANY	MT	Subbituminous	2X390	PC	0.0064		DFGD	Permit issued	BACT-PSD	RBLC/Reg Spreadsheet
MUSTANG GENERATING STATION	MUSTANG ENERGY (PEABODY)	NM	Subbituminous	300	PC	0.0066		DFGD	Under review - BACT unresolved	BACT-PSD	Reg Spreadsheet
IATAN GENERATING STATION (UNIT 2)	KANSAS CITY POWER & LIGHT	MO	Subbituminous	800	PC	0.0072		WFGD	Permit issued	Net Out-PSD	RBLC/Reg Spreadsheet
MAIDSVILLE	LONGVIEW POWER, LLC	WV	Bituminous	600	PC	0.0075	3-Hr	WFGD/Inj/FF	Permit issued	BACT-PSD	RBLC
PEE DEE GENERATING STATION	SANTEE COOPER	SC	Bituminous/Pet Coke	2X660	PC	0.0075	3-Hr	WFGD	Proposed	BACT-PSD	Reg Spreadsheet

H2SO4 Top Down RBLC Clearinghouse Technology Review Results

FACILITY	COMPANY	STATE	FUEL	SIZE (MW)	BOILER TECHNOLOGY	LIMIT (lb/mmBtu)	AVERAGING PERIOD	CONTROL TECHNOLOGY	STATUS	NSR BASIS	DATA SOURCE
AMERICAN MUNICIPAL POWER OHIO GENERATING STATION	AMP-OHIO	OH	Subbituminous/Bituminous Blend	2x480	PC	0.0075	3-Hr	WFGD	Proposed	BACT-PSD	Reg Spreadsheet
ELM ROAD GENERATING STATION (EXISTING OAK CREEK FACILITY	WISCONSIN ENERGY	WI	Subbituminous	2X615	PC	0.0100		WFGD	Permit Issued	BACT-PSD	Reg Spreadsheet
RIVER HILL POWER COMPANY, LLC	RIVER HILL POWER COMPANY, LLC	PA	Waste Coal	290	CFB	0.0100			Permit issued	BACT-PSD	RBLC
TWIN OAKS POWER PLANT (UNIT 3)	SEMPRA GENERATION	TX	Lignite	600	PC	0.0200		WFGD	Proposed	BACT-PSD	Reg Spreadsheet
PRAIRIE STATE GENERATING STATION	PEABODY	IL	Bituminous	2X750	PC	0.0390		WFGD	Permit issued - under appeal	BACT-PSD	Reg Spreadsheet
DESERT ROCK ENERGY FACILITY	SITHE GLOBAL	NM	Subbituminous	2X750	PC			WFGD	Proposed	BACT-PSD	Reg Spreadsheet-NO SAM Limit
COTTONWOOD ENERGY CENTER	BHP BILLITON	NM	Subbituminous	500	PC			WFGD	Proposed	BACT-PSD	Reg Spreadsheet-NO SAM Limit
TOUQUOP ENERGY PROJECT	TOUQUOP ENERGY PROJECT	NV	Subbituminous	750	PC			WFGD	Proposed	BACT-PSD	Reg Spreadsheet-NO SAM Limit
ELY ENERGY CENTER	SIERRA PACIFIC & NV POWER	NV	Subbituminous	2X750	PC			WFGD	Proposed	BACT-PSD	Reg Spreadsheet-NO SAM Limit
WYGEN 3	BLACK HILLS CORPORATION	WY	Subbituminous	100	PC			DFGD	Permit issued	BACT-PSD	RBLC-NO SAM Limit
WHITEPINE ENERGY STATION	LS POWER DEVELOPMENT	NV	PRB	3x530	PC			DFGD	Proposed	BACT-PSD	Reg Spreadsheet-NO SAM Limit
WYGEN 2	BLACK HILLS CORPORATION	WY	Subbituminous	500	PC			DFGD	Permit issued	BACT-PSD	RBLC-NO SAM Limit
BIG CAJUN II POWER PLANT	LOUISIANA GENERATING, LLC	LA	Subbituminous	675	PC			WFGD	Permit issued	BACT-PSD	RBLC-NO SAM Limit
HUNTER	PACIFICORP	UT	Subbituminous	575	PC			WFGD	Proposed	Net Out-PSD	Reg Spreadsheet-NO SAM Limit
LAMAR LIGHT & POWER POWER PLANT	LAMAR UTILITIES BOARD DBA LAMAR LIGHT & POWER	CO	Subbituminous/Bituminous Blend	44	CFB			Limestone Inj	Permit issued	BACT-PSD	RBLC/Reg Spreadsheet-NO SAM Limit
WHELAN ENERGY CENTER	HASTINGS UTILITIES	NE	Subbituminous	220	PC			DFGD	Permit issued	BACT-PSD	RBLC/Reg Spreadsheet-NO SAM Limit
INDECK ELWOOD	INDECK ELWOOD	IL	Bituminous	2X330	CFB			Limestone Inj	Permit issued - under appeal - EAB remand	BACT-PSD	Reg Spreadsheet-NO SAM Limit
PALATKA GENERATIING STATION	SEMINOLE ELECTRIC COORP	FL	Bituminous	800	PC			WFGD	Proposed	Net Out-PSD	Reg Spreadsheet-NO SAM Limit

Color Code Legend

Data from EPA Regions 4 and 7 Spreadsheet
Data from Draft Application
Data from EPA's RBLC Clearinghouse

Attachment B
SO_3 Testing Results
Ghent 3

Client: **E.ON US**
Plant: **Ghent Unit 3**
Location: **Stack**

Run Number:	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Date:	4/17/2009	4/17/2009	4/17/2009	4/17/2009	4/17/2009	4/17/2009	4/17/2009	4/17/2009
Run Time: Start	9:45	10:20	11:30	12:08	13:10	13:56	14:50	15:27
End	10:15	10:50	12:00	12:38	13:40	14:26	15:20	15:57
Pbar - Barometric Pressure:	29.60	29.60	29.60	29.60	29.60	29.60	29.60	29.60
TT - Sampling Time:	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
VM - Meter Volume:	17.890	17.101	17.027	17.139	16.897	17.012	16.137	16.957
TM - Avg. Meter Temp (F):	71	74	76	78	79	81	83	85
PM - Avg. Delta H (in. of H2O):	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Y - Meter Calibration Factor:	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01
VMSTD - Std. Gas Volume (SCF):	17.828	16.933	16.810	16.842	16.571	16.619	15.704	16.464
Vlc - Volume Water Collected:	67	70	64	67	66	64	65	67
%M - Percent Moisture:	15.04	16.30	15.21	15.78	15.80	15.35	16.31	16.08
Bws - Mole Fraction, Dry:	0.150	0.163	0.152	0.158	0.158	0.154	0.163	0.161
%CO2 - Carbon Dioxide, Dry:	12.0	12.0	11.9	11.9	12.2	12.2	12.1	12.1
%O2 - Oxygen, Dry:	7.5	7.5	7.5	7.5	7.2	7.2	7.5	7.5
MD - Dry Molecular Weight:	30.22	30.22	30.20	30.20	30.24	30.24	30.24	30.24
MS - Wet Molecular Weight:	28.38	28.23	28.35	28.28	28.31	28.36	28.24	28.27
PS - Static Press. (in. of Hg):	29.57	29.57	29.57	29.57	29.57	29.57	29.57	29.57
SO3								
Emission Concentration (gr/dscf):	0.006	0.015	0.016	0.015	0.011	0.015	0.015	0.013
Emission Concentration (ppm):	4.3	10.0	10.7	10.1	7.7	10.2	10.1	9.0
Emission Rate (lb/mmBtu):	0.014	0.032	0.034	0.032	0.024	0.032	0.032	0.029
Opacity (%):	18.3	18.0	15.5	16.1	16.2	16.0	15.2	14.1
Trona Injection Rates								
Inlet (lbs/hour)	1250	1250	1000	1000	0	0	1500	1500
Outlet (lbs/hour)	1250	1250	1000	1000	1500	1500	1500	1500
Unit Information								
MW	513	514	512	515	515	514	514	514

Attachment C
Emissions Estimate

Kentucky Utilities (KU) - E.W. Brown Unit 3
H_2SO_4 BACT Analysis
Emissions Estimate Rev. 3

	Uncontrolled	Reference	Controlled Sorbent Inj.	Reference
Ultimate Coal analysis, as received				
Carbon, %	60.30	Ref 1		
Hydrogen, %	4.50	Ref 1		
Sulfur, %	3.80	Ref 3		
Nitrogen, %	1.17	Ref 1		
Oxygen, %	6.80	Ref 1		
Chlorine, %	0.07	Ref 1		
Ash, %	13.80	Ref 1		
Moisture, %	9.56	Ref 1		
Total, %	100.00	Calculated		
Higher Heating Value, Btu/lb	11,000.00	Ref 1		
Unit Characteristics				
Unit Rating, Gross MW	457	Ref 1		
Unit Rating, Net MW	433	Ref 1		
Boiler Type	Tangential	Ref 1		
Boiler Manufacturer	CE	Ref 1		
Net Unit Heat Rate, Btu/kWh	10,150	Ref 1		
Boiler Heat Input, mmBtu/hr (HHV)	5,300.0	Ref 1		
Coal Flow Rate, lb/hr	481,818	Calculated		
Coal Flow Rate, tons/month	173,455	Note 4		
Capacity Factor, %	75	Year 2017		
Fly Ash Portion of Total Ash, %	80	Ref 1		
Boiler Economizer Outlet Conditions				
Flue Gas Temperature, F	700	Ref 1		
Flue Gas Pressure, in. w.g.	-4.5	Ref 1		
Flue Gas Composition				
Sulfur Dioxide (SO_2), lb/mmBtu	6.90	Calculated		
Sulfur Dioxide (SO_2), lb/hr	36,580	Calculated		
Sulfur Trioxide (SO_3), lb/hr	457	Note 1		
Sulfur Trioxide (SO_3), lb/mmBtu	0.086	Calculated		
SCR Outlet Conditions				
Sulfur Trioxide (SO_3), lb/hr	1,371	Note 1		
Sulfur Trioxide (SO_3), lb/mmBtu	0.259	Calculated		
Air Heater Outlet Conditions				
Flue Gas Temperature, F	330	Ref 1		
Flue Gas Pressure, in. w.g.	-16.5	Ref 1		
Flue Gas Composition				
Sulfur Trioxide (SO_3), lb/hr	1,303	Note 2 (a)		
Sulfur Trioxide (SO_3), lb/mmBtu	0.246	Calculated		
Cold-Side ESP Outlet Conditions				
Flue Gas Temperature, F	330	Ref 1		
Flue Gas Pressure, in. w.g.	-17.0	Ref 1		
Flue Gas Composition				
Sulfur Trioxide (SO_3), lb/hr	1,238	Note 2 (b)	359	Note 2 (c)
Sulfur Trioxide (SO_3), lb/mmBtu	0.234	Calculated	0.068	Calculated

FGD Outlet Conditions				
Flue Gas Temperature, F	128.00	Ref 1		
Flue Gas Pressure, in. w.g.	0.5	Ref 1		
Flue Gas Mass Flow Rate, lb/hr	6,356,503	Ref 2, Note 3		
Flue Gas Wet Molecular Weight, lb/mole	28.32	Ref 2		
Flue Gas Molar Flow Rate, moles/hr	224,453	Calculated		
Flue Gas Composition				
Sulfur Trioxide (SO_3), lb/hr	619	Note 2 (d)	180	Note 2 (d)
Sulfur Trioxide (SO_3), lb/mmBtu	0.117	Calculated	0.034	Calculated
Sulfur Trioxide (SO_3), ppmvw @ actual O_2	34	Calculated	10	Calculated
Sulfuric Acid Mist (H_2SO_4), lb/hr	758	Calculated	220	Calculated
Sulfuric Acid Mist (H_2SO_4), lb/mmBtu	0.143	Calculated	0.042	Calculated
Sulfuric Acid Mist (H_2SO_4), ppmvw @ actual O_2	34	Calculated	10	Calculated
Annual Emissions Estimate				
Sulfuric Acid Mist (H_2SO_4), ton/yr	2,490	Calculated	723	Calculated

Notes:

1. Sulfur dioxide to sulfur trioxide conversion is assumed to be:
   a. Across boiler = 1.0%
   b. Across SCR catalyst = 2.0%

2. Sulfur trioxide removal is assumed to be:
   a. Across air heater = 5% (from ref 3)
   b. Across ESP = 5% (from ref 3)
   c. Sorbent injection before (incl.) ESP = 71% estimated performance level
   d. Across FGD = 50% (from Fluor/BPI FGD performance guarantee)
   e. Total reduction = 84%

3. BR3 FGD outlet mass flow rate is based on ratio of BR3 FGD inlet mass flow rate to total FGD inlet mass flow rate applied to the total FGD outlet mass flow rate as shown in Ref 2.

4. Coal flow rate (tons/month) based on 24 hour/day and 30 day/month and 100% capacity factor.

References

1. BACT Analysis Information Request response, J. Wilkerson, 4/8/09.
2. Brown FGD Project Process Flow Diagram, BRO-M-00001/2, J. Wilkerson, 4/27/09.
3. E-mail from J. Wilkerson, 5/19/09.

Revision History

Rev	Date	Purpose
0	5/4/2009	Initial issue
1	5/19/2009	Revised as per client's comments
2	5/20/2009	Revised as per client's comments
3	7/1/2009	Revised as per client's comments

4.0 Ambient Air Quality Impact Analysis

The following section discusses the air dispersion modeling methodology and the modeling results from the ambient air quality impact analysis for the proposed project. This air quality analysis was performed for those PSD pollutants subject to PSD review (i.e., H_2SO_4). In addition, the ambient air quality analysis was performed to address any concerns under 401 KAR 63:020. Since the PSD pollutant is not subject to an ambient air quality standard or PSD increment, it is not a PSD requirement to determine the air quality impacts associated with this project. However, we have chosen to proactively demonstrate that the proposed project does not cause adverse ambient impacts.

4.1 PSD Pollutant Modeling Results

The AERMOD model was run for each of the five one-year periods as listed in the modeling analysis. To evaluate both short and long term impacts, both one-hour averages and annual averages were calculated to compare against the applicable risk threshold. The emission rates used in the modeling were maximum predicted future H_2SO_4 emissions for Brown Units 1 and 2 plus the proposed 220 lbs/hour BACT emission limit for Unit 3.

The maximum one-hour impact hazard quotient (HQ) of 0.14 occurs just beyond the property boundary southeast of the boiler stack and the maximum annual average impact HQ of 0.20 occurs to the northeast of the plant site across the Dix River and southeast of Bowman's Bend. The maximum HQ value of 0.20 demonstrates that the potential H_2SO_4 emissions from the new boiler stack after the project will not pose an adverse health risk at any offsite location. Table 4-1 summarizes the AERMOD modeling results.

The detailed H_2SO_4 air dispersion modeling analysis and risk assessment which lists all modeling assumptions, methodology, and modeling inputs and outputs are contained in Appendix H.

Table 4-1
Maximum Modeled Offsite H_2SO_4 Concentrations and Hazard Quotients

Averaging Period	Year	Risk Thresholds (b) (µg/m^3)	Maximum 1st High Impact (µg/m^3)	Maximum Hazard Quotient (µg/m^3)	Below Risk Threshold Levels (Yes/No)
1-hour (a)	1992-LEX (Max. of 5 yrs)	100	13.59	0.14	Yes
Annual (a)	1990-LEX (Max. of 5 yrs)	1.0	0.20	0.20	Yes

a. Evaluated 1st high impacts for each year modeled since risk thresholds are not to be exceeded.

b. Acute (1-hour) H_2SO_4 risk threshold is based on the North Carolina Division for Air Quality Acceptable Ambient Level under the State's Air Toxics Program. Non-cancer chronic (annual) H_2SO_4 risk threshold is based on the Louisville Metro Air Pollution Control District (LMAPCD) Benchmark Ambient Concentration (BAC).

5.0 MACT Analysis

There is no applicable MACT standard for the E.W. Brown Unit 3 Project, construction of a SCR. The pollutants of concerns are NOx, which will decrease, and sulfuric acid mist. The addition of the SCR will not create or increase any Hazardous Air Pollutants (HAPs). Therefore, no MACT analysis was performed.

6.0 Additional PSD Impact Analyses

Federal PSD regulations require additional analysis of impacts due to construction and operation of a new major stationary source or modified existing sources. The analysis considers impairment to visibility, impacts on soils and vegetation, as well as projected air quality impacts that may occur as the result of general commercial, residential, industrial, and other growth associated with the new major stationary source or modified existing sources.

6.1 Commercial, Residential, and Industrial Growth

Limited additional commercial, residential, and industrial growth will result from the project. This growth will be the result of an increase in workforce during the construction of the project. The construction phase will last approximately 24-months. Construction employment of approximately 400 workers is expected over the course of the construction period. Since the construction of the project will be temporary, the growth associated with project construction will be short-term and the effects to the ambient air quality are expected to be insignificant.

Project employment reflecting full time jobs directly tied to the operation of the proposed project will likely increase by four operators. Consequently, a quantitative assessment of growth-related air quality impacts due to full time jobs was not conducted.

6.2 Vegetation

The following sub-sections briefly describe the potential effects of sulfuric acid mist (H_2SO_4) produced by the proposed project on the nearby vegetation and soils.

6.2.1 Sulfuric Acid Mist (H_2SO_4)

H_2SO_4 is directly emitted by power plants. H_2SO_4 is formed as a result of combustion chemistry and air quality control system chemistry. Sulfur in the fuel converts to sulfur dioxide (SO2) via combustion chemistry. SO2 converts to sulfur trioxide (SO3) when Selective Catalytic Reduction (SCR) control is utilized. SO3 further converts to form H_2SO_4 when moisture is present in the stack or ambient air. However, due to good combustion practices and the use of a SO_3 "Mitigation System" which is highly effective at reducing SO_3 emissions, SO_3 emissions (and therefore H_2SO_4) will be reduced to a negligible increase. Consequently, no adverse impacts to vegetation at or near the proposed project are expected from H_2SO_4 emissions.

6.3 Soils

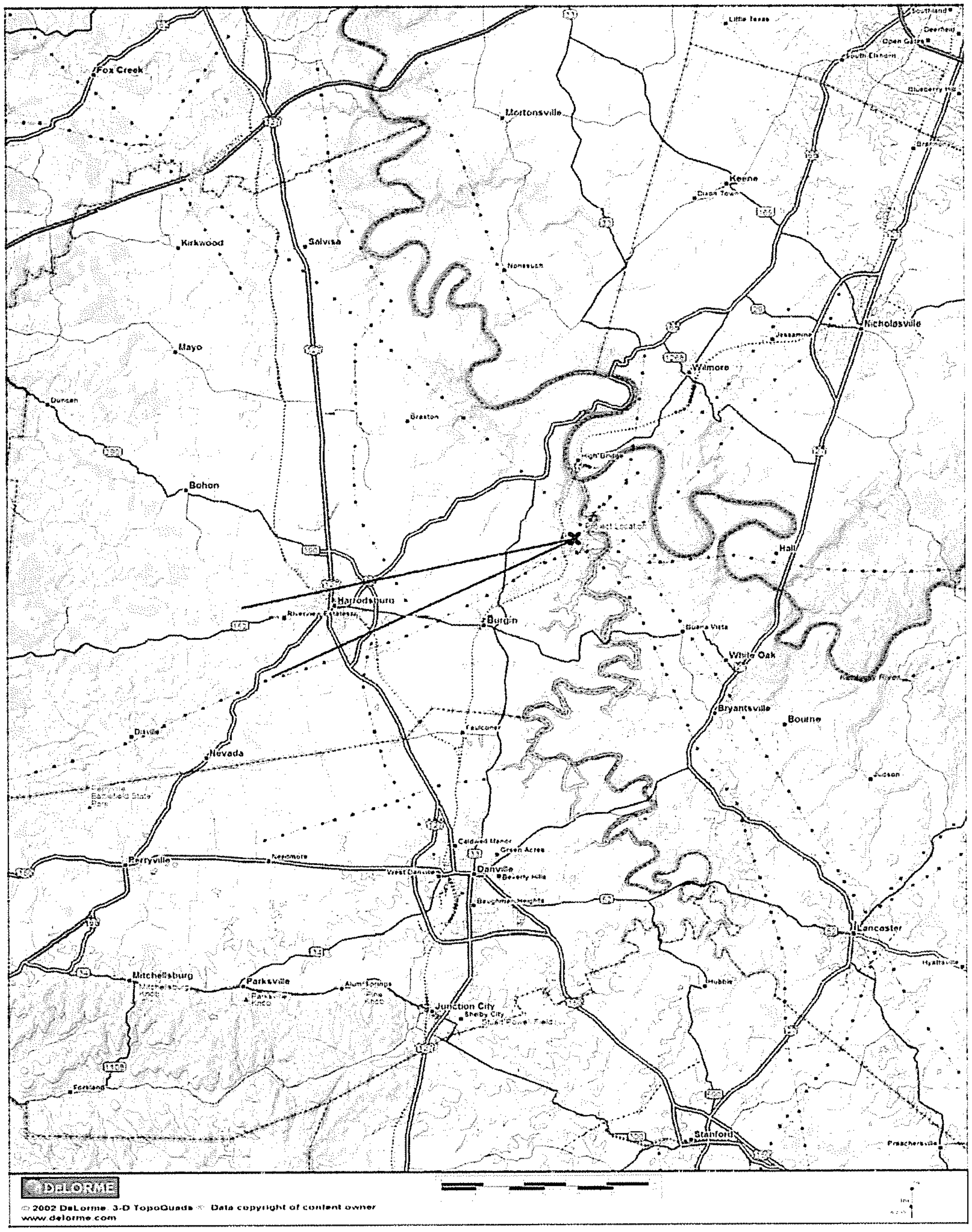
Ten dominant soil types are mapped out or are in the immediate vicinity of the project site. They include the following:

- Chenault gravelly silt loam, 2 to 6 percent slopes (CmB).
- Chenault gravelly silt loam, 6 to 12 percent slopes (CmC).
- Fairmount-Rock outcrop complex, 6 to 12 percent slopes (FaC).
- Fairmount-Rock outcrop complex, 12 to 30 percent slopes (FaD).
- Fairmount-Rock outcrop complex, 30 to 60 percent slopes (FaF).
- Maury silt loam, 2 to 6 percent slopes (MaB)
- Maury silt loam, 6 to 12 percent slopes (MaC)
- McAfee silt loam, 2 to 6 percent slopes (McB)
- McAfee silt loam, 6 to 12 percent slopes (McC)
- McAfee silt loam, 12 to 20 percent slopes (McD)

Sulfates caused by H_2SO_4 deposition onto the soils can be beneficial and detrimental to soil depending on its composition. However, as stated previously, the proposed project will have a negligible increase in H_2SO_4 emissions, as such, is not expected to have an adverse impact to the soils in the immediate vicinity.

6.4 Class II Visibility

E.W. Brown Generating Station is located in Mercer County, Kentucky. The KDAQ has not identified any areas of potential visibility concern for the proposed project. However, as visibility analyses are a requirement for PSD air permit applications, the proposed project has chosen to analyze its impact upon Class II visibility at the nearby town of Harrodsburg, Kentucky, located approximately 8.7 km southwest of the proposed project location. Figure 6-1 illustrates the location of Harrodsburg with respect to the proposed project.



Location of Class II Vista
For Visibility Analysis
Figure 6-1

As defined in the CAA, the PSD requirements provide for a system of area classifications. Class I areas are generally national parks and wilderness areas. Class II areas are areas that can accommodate well-managed industrial growth. As such, visibility analyses were performed to evaluate the potential for visibility impairment inside the selected Class II scenic vista.

Due to emissions control technologies that are being applied to the project, as previously described in Section 2, the effects on visibility are expected to be insignificant at Harrodsburg. Specifically, the technologies that are being applied include the use of SCR for NOx control, a wet flue gas desulphurization (WFGD) system for SO_2, and a SO_3 mitigation system (sorbent injection) to control H_2SO_4 emissions. These control systems will minimize significant visibility impacts.

6.4.1 Model Input Source Parameters and Methodology

6.4.1.1 Visual Impairment Screening Assessment

A visibility impairment screening analysis was conducted at the aforementioned Class II area to provide a conservative indication of the perceptibility of plumes from the proposed project. The analysis was performed in accordance with the USEPA's *Workbook for Plume Visual Impact Screening and Analysis* (EPA-450/4-88-015, September 1988, hereinafter referred to as the "Workbook"), using the VISCREEN model. It should be noted that the visibility impairment analysis and model VISCREEN are typical for assessments in PSD Class I areas where visibility preservation is a factor in the permit approval process. However, since no Class II visibility model is available, this model and the methodology for Class I areas as outlined in the Workbook were used.

Distinct from a Class I visibility analysis, the analysis presented herein in concerned with visibility impairment within a Class II sensitive area. The general components of a visibility impairment analysis include the following:

- Determination of the visual quality of the area.
- Determination of the potential for visibility impairment with a screening level assessment.
- If warranted, a more in-depth analysis of the visibility impairment potential.

In accordance with the workbooks visual screening procedures, the VISCREEN plume visual impact screening model would first be used with default worst-case Level 1 screening parameters. However, it is important to note that Level 1 analysis incorporate numerous worst-case default assumptions and parameters. As such, and in accordance with USEPA guidance, a more representative worst-case Level 2 screening analysis with situation-specific input parameters for just wind speed was conducted. Table 6-1 presents the Level 2 visual screening parameters used in the VISCREEN modeling. Many of the input parameters for the Level 2 analysis are the same as the default worst-case values for a Level 1 analysis specified in the Workbook. The shaded parameters in Table 6-1 designate the more representative, situation-specific wind speed inputs of the

Level 2 analysis. The situation specific Level 2 screening parameters are described below.

6.4.1.2 Emissions

The expected hourly SO_4 emissions (as H_2SO_4) from the boiler were used in the visibility analysis. This value can be found in Appendix E.

6.4.1.3 Wind Speed

The worst-case Level 1 VISCREEN default value for wind speed of 1m/sec was found not to be representative of the general climatological conditions in the vicinity of the proposed project. Therefore, wind speed data for Fayette County (Lexington, Kentucky area) for the previous year (prior to April 2009) was analyzed to determine a more representative worst-case wind speed value.

The results of the meteorological analyses are presented in Table 6-1 as the shaded wind speed values.

6.4.2 Level 2 Visibility Summary

The VISCREEN model was used with the aforementioned representative, worst-case, situation-specific Level 2 input parameters as identified in Table 6-1. Results of the VISCREEN modeling are included in Table 6-2 for Harrodsburg, Kentucky. The modeling methodology utilized is designed for Class I areas. The areas presented in this analysis are classified as Class II, and as such, have no set criteria from which to evaluate visual impacts. However, the USEPA's *Workbook for Estimating Visibility Impairment* (EPA 450-80-031) has adopted general criteria for use in a visibility analysis. These criteria indicate that if the absolute value of contrast is greater than 0.1 or Delta E is greater than 4.0, the possibility exists that the visual impact would be judged adverse or significant. Based on the above reference, the results presented in Table 6-2 indicate that the proposed project will not have an adverse or significant impact upon visibility within the Class II area of Harrodsburg. VISCREEN model input/output parameters are contained in Appendix I.

Table 6-1
VISCREEN Level 2 Model Inputs

VISCREEN Modeling Parameter	Level 2 (Representative Worst-case Analysis) (a)
	Harrodsburg, Kentucky
Particulate Emissions (b)	0 lb/hr
NO_x (as NO_2) Emissions (b)	0 lb/hr
Primary NO_2 Emissions	0 lb/hr (model default)
Soot Emissions	0 lb/hr (model default)
Sulfate Emissions (SO_4) (b)	45 lb/hr
Source-Observer Distance	8.7 km
Minimum Source Class II Distance	8.7 km
Maximum Source Class II Distance	10 km
Background Visual Range (c)	20 km
Plume –Source-Observer Angle	11.25 degrees
Background Ozone Concentration	0.04ppm
Stability Class	F
Wind Speed (c,d)	3.2 m/sec
Background Fine Particulate Density	1.5 g/cm^3
Background Fine Particulate Size Index	0.3 μ/m
Background Coarse Particulate Density	2.5g/cm^3
Background Coarse Particulate Size Index	6.0 μ/m
Plume Particulate Density	2.5 g/cm^3
Plume Particulate Size Index	2.0 μ/m
Plume Soot Density	2.0 g/cm^3
Plume Soot Size Index	0.1 μ/m
Plume Primary SO_4 Density.	1.5g/cm^3
Plume Primary SO_4 Size Index	0.5 μ/m

(a) VISCREEN model default values.
(b) Performance data as described in Appendix E.
(c) Worst case situation specific parameter.
(d) Meteorological data analyzed from Fayette County (Lexington, Kentucky) for the previous year (up to April 2009).

Table 6-2 VISCREEN Level 2 Model Results for "Inside the Class II Area"			
Background	Distance (km)	Delta E Plume [(a)]	Contrast Plume [(a)]
Sky	10.0	1.5	-0.014
Terrain	8.7	3.8	0.039

[(a)] While there are no Delta E or contrast criteria thresholds for Class II areas, the USEPA's *Workbook for Estimating Visibility Impairment* uses a Delta E of greater than 4 or a contrast of greater than 0.1 as having a threshold for having an adverse impact upon visibility.

Appendix I
Class II Visibility Analysis Modeling Input/Output

7.0 Class I Area Impact Analyses

The PSD regulations require the source to consider its impact on Class I areas. The closest Class I area, Mammoth Cave National Park, is located 77 miles (115 km) southwest of the E.W. Brown Station. The Class I impact analysis typically address two issues; visibility impacts and Class I increment consumption.

Class I increments only apply to PM/PM_{10}, SO_2 and NO_x. Since this project only has an increase in sulfuric acid mist emissions (NO_x emissions are reduced), there will be no Class I increment consumption associated with this project.

Based on VISCREEN Level 2 visibility modeling results provided in Section 6.4 of the PSD application, it was demonstrated that the SCR project did not have an adverse visibility impact near the facility (Class II area). Based on this modeling it is predicted that visibility impacts at Mammoth Cave (115 km – southwest) will also be insignificant.

ATTACHMENT A

Commonwealth of Kentucky
Natural Resources & Environmental Protection Cabinet
Department for Environmental Protection

Division for Air Quality
803 Schenkel Lane
Frankfort, Kentucky 40601

DEP7007AI

Administrative Information

Enter if known
AFS Plant ID#

Agency Use Only

Date Received

Log#

Permit#

PERMIT APPLICATION

The completion of this form is required under Regulations 401 KAR 52:020, 52:030, and 52:040 pursuant to KRS 224. Applications are incomplete unless accompanied by copies of all plans, specifications, and drawings requested herein. Failure to supply information required or deemed necessary by the division to enable it to act upon the application shall result in denial of the permit and ensuing administrative and legal action. Applications shall be submitted in triplicate.

1) APPLICATION INFORMATION

Note: The applicant must be the owner or operator (The owner/operator may be individual(s) or a corporation)

Name: Kentucky Utilities Company/E.W. Brown Generating Station

Title: ______ **Phone:** (502) 627-2343

Mailing Address: (If applicant is an individual)
Company Louisville Gas & Electric Company

Street or P.O. Box: P.O. BOX 32010

City: Louisville **State:** KY **Zip Code:** 40232

Is the applicant (check one): ☐ Owner ☐ Operator ☐ Owner & Operator ☒ Corporation/LLC* ☐ LP**

* If the applicant is a Corporation or a Limited Liability Corporation, submit a copy of the current Certificate of Authority from the Kentucky Secretary of State.

** If the applicant is a Limited Partnership, submit a copy of the current Certificate of Limited Partnership from the Kentucky Secretary of State.

Person to contact for technical information relating to application:

Name: Marlene Zeckner Pardee

Title: Senior Environmental Scientist **Phone:** 502-627-2343

2) OPERATOR INFORMATION

Note: The applicant must be the owner or operator (The owner/operator may be individual(s) or a corporation)

Name: Same as Applicant

Title: ______ **Phone:** ______

Mailing Address:
Company ______

Street or P.O. Box: ______

City: ______ **State:** ______ **Zip Code:** ______

DEP7007AI
(Continued)

3) TYPE OF PERMIT APPLICATION

For new sources that currently *do not* hold *any* air quality permits in Kentucky and are required to obtain a permit prior to construction pursuant to 401 KAR 52:020, 52:030, or 52:040.

☐ Initial Operating Permit (the permit will authorize both construction and operation of the new source)

Type of Source (*Check all that apply*): ☐ Major ☐ Conditional Major ☐ Synthetic Minor ☐ Minor

For existing sources that do not have a source-wide Operating Permit required by 401 KAR 52:020, 52:030, or 52:040.

Type of Source (*Check all that apply*): ☐ Major ☐ Conditional Major ☐ Synthetic Minor ☐ Minor

(*Check one only)*
☐ Initial Source-wide Operating Permit ☐ Construction of New Facilities at Existing Plant
☐ Construction of New Facilities at Existing Plant ☐ Modification of Existing Facilities at Existing Plant
☐ Other (explain) ______

For existing sources that currently have a source-wide Operating Permit.

Type of Source (*Check all that apply*): ☒ Major ☐ Conditional Major ☐ Synthetic Minor ☐ Minor

Current Operating Permit # V-03-034

☐ **Administrative Revision** (describe type of revision requested, e.g. name change): ______

☐ **Permit Renewal** ☐ **Significant Revision** ☐ **Minor Revision**

☐ **Addition of New Facilities** ☒ **Modification of Existing Facilities**

For all construction and modification requiring a permit pursuant to 401 KAR 52:020, 52:030, or 52:040.

Proposed Date for Start of Construction or Modification: 2010

Proposed date for Operation Start-up: 2012

4) SOURCE INFORMATION

Source Name: Kentucky Utilities Company/E.W. Brown Generating Station

Source Street Address: 815 Dix Dam Road

City: Harrodsburg **Zip Code:** 40330 **County:** Mercer

Primary Standard Industrial Classification (SIC) Category: Electric Services **Primary SIC #:** 4911

Property Area (Acres or Square Feet): 907.43 acres **Number of Employees:** 121

Description of Area Surrounding Source (*check one*):
☐ Commercial Area ☐ Residential Area ☐ Industrial Area ☐ Industrial Park ☒ Rural Area ☐ Urban Area

Approximate Distance to Nearest Residence or Commercial Property: < 0.5 mile

UTM or Standard Location Coordinates: (*Include topographical map showing property boundaries*)

UTM Coordinates: Zone 16 Horizontal (km) 701.3 Vertical (km) 4184.7

Standard Coordinates: Latitude ____ Degrees ____ Minutes ____ Seconds
Longitude ____ Degrees ____ Minutes ____ Seconds

DEP7007AI

(Continued)

4) SOURCE INFROMATION (CONTINUED)

Is any part of the source located on federal land? ☐ Yes ☒ No

What other environmental permits or registrations does this source currently hold in Kentucky?

Kentucky Division of Waste Management Certificate of Registration-EPA ID #KYD-000-622-951
Kentucky Division of Water KPDES Permit #KY0002020

What other environmental permits or registrations does this source need to obtain in Kentucky?

5) OTHER REQUIRED INFORMATION

Indicate the type(s) and number of forms attached as part of this application.

1	DEP7007A	Indirect Heat Exchanger, Turbine, Internal ___ Combustion Engine
___	DEP7007B	Manufacturing or Processing Operations
___	DEP7007C	Incinerators & Waste Burners
___	DEP7007F	Episode Standby Plan
___	DEP7007J	Volatile Liquid Storage
___	DEP7007K	Surface Coating or Printing Operations
___	DEP7007L	Concrete, Asphalt, Coal, Aggregate, Feed, Corn, Flour, Grain, & Fertilizer
___	DEP7007M	Metal Cleaning Degreasers
1	DEP7007N	Emissions, Stacks, and Controls Information
___	DEP7007P	Perchloroethylene Dry Cleaning Systems

___	DEP7007R	Emission Reduction Credit
___	DEP7007S	Service Stations
___	DEP7007T	Metal Plating & Surface Treatment Operations
1	DEP7007V	Applicable Requirements & Compliance Activities
___	DEP7007Y	Good Engineering Practice (GEP) Stack Height Determination
___	DEP7007AA	Compliance Schedule for Noncomplying Emission Units
___	DEP7007BB	Certified Progress Report
___	DEP7007CC	Compliance Certification
1	DEP7007DD	Insignificant Activities

Check other attachments that are part of this application.

Required Data

☐ Map or Drawing Showing Location
☐ Process Flow Diagram and Description
☐ Site Plan Showing Stack Data and Locations
☒ Emission Calculation Sheets
☒ Material Safety Data Sheets (MSDS)

Supplemental Data

☐ Stack Test Report
☐ Certificate of Authority from the Secretary of State (for Corporations and Limited Liability Companies)
☐ Certificate of Limited Partnership from the Secretary of State (for Limited Partnerships)
☐ Claim of Confidentiality (See 400 KAR 1:060)
☐ Other (Specify) ______________________

Indicate if you expect to emit, in any amount, hazardous or toxic materials or compounds or such materials into the atmosphere from any operation or process at this location.

☐ Pollutants regulated under 401 KAR 57:002 (NESHAP)
☒ Pollutants listed in 401 KAR 63:060 (HAPS)
☐ Pollutants listed in 40 CFR 68 Subpart F [112(r) pollutants]
☐ Other

Has your company filed an emergency response plan with local and/or state and federal officials outlining the measures that would be implemented to mitigate an emergency release?

☒ Yes ☐ No

Check whether your company is seeking coverage under a permit shield. If "Yes" is checked, applicable requirements must be identified on Form DEP7007V. Identify any non-applicable requirements for which you are seeking permit shield coverage on a separate attachment to the application.

☐ Yes ☒ No ☐ **A list of non-applicable requirements is attached**

DEP7007AI
(Continued)

6) OWNER INFORMATION

Note: If the applicant is the owner, write "same as applicant" on the name line.

Name: Same as Applicant

Title: ______________________ **Phone:** ______________________

Mailing Address:
Company ______________________

Street or P.O. Box: ______________________

City: ______________________ **State:** ______ **Zip Code:** ______________________

List names of owners and officers of your company who have an interest in the company of 5% or more.

Name	**Position (owner, partner, president, CEO, treasurer, etc.)**

(attach another sheet if necessary)

7) SIGNATURE BLOCK

I, the undersigned, hereby certify under penalty of law, that I am a responsible official, and that I have personally examined, and am familiar with, the information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including the possibility of fine or imprisonment.

BY: Ralph Bowling
(Authorized Signature)

7/5/09
(Date)

Ralph Bowling
(Typed or Printed Name of Signatory)

Vice President Power Production
(Title of Signatory)

Commonwealth of Kentucky
Natural Resources & Environmental Protection Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit.
Make additional copies as needed)

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 017 (new stack)
Emission Unit # 03

1) **Type of Unit (Make, Model, Etc.):** Combustion Engineering Pulverized Coal Boiler

Date Installed: 7/19/71 **Cost of Unit:** $16.5 million
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Unit 3

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** X
2. **Gas Turbine for Electricity Generation** ____
3. **Pipe Line Compressor Engines:**
   - ____ **Gas Turbine**
   - ____ **Reciprocating engines**
     - **(a) 2-cycle lean burn** ____
     - **(b) 4-cycle lean burn** ____
     - **(c) 4-cycle rich burn** ____
4. **Industrial Engine** ____

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** 5,300
2. **Power output (hp):** ____
   Power output (MW): ____

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

X **A. Coal** ____ **B. Fuel Oil #** *(Check one)* ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

____ **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): ____

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	20	3.8	11,000	11,000
Secondary	20	3.8	11,000	11,000

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate (*please specify units*)*:** Not Applicable

7) **Fuel Source or supplier:** Numerous – changes frequently

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

___ hours/day _______ days/week _______ weeks/year

9) If this unit is multipurpose, describe percent in each use category:

Space Heat ________% Process Heat ___________ % Power _________ %

10) Control options for turbine/IC engine (*Check*)

__ (1) Water Injection
__ (2) Steam Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Combustion Modification)
__ (5) Other (*Specify*) ______________________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

__X__ Pulverized Coal Fired:

__X__ Dry Bottom
_ Wall Fired
__ Wet Bottom
_X_ Tangentially Fired

_________ Cyclone Furnace

_________ Overfeed Stoker

_________ Fluidized Bed Combustor:
______ Circulating Bed
______ Bubbling Bed

Fly Ash Rejection:

☐ Yes ☐ No

_______ Spreader Stoker

_______ Underfeed Stoker

_______ Hand-fed

_______ Other (*specify*) ______________________

12) Oil-Fired Unit

______ Tangentially (Corner) Fired

_______ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

______ Dutch Oven/Fuel Cell Oven _______ Stoker _______ Suspension Firing

______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

15) **Combustion Air** **Draft: ________ Natural __X__ Induced**

Forced Pressure __________ lbs/sq. in.

Percent excess air (air supplied in excess of theoretical air) __15-40__ %

SECTION III

16) **Additional Stack Data**

A. Are sampling ports provided? ☒ Yes ☐ No
B. If yes, are they located in accordance with 40 CFR 60*? ☒ Yes ☐ No
C. List other units vented to this stack : Units 1& 2

17) **Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.**

18) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**

Coal Handling System – Coal is shipped to the site in unit trains and/or trucks. Coal is unloaded at a maximum rate of 1,640 tons per hour. The coal is either diverted to an open storage pile or it is transferred via conveyor to a crusher house. The crushed coal is then conveyed to coal storage bunkers for feed into the coal-fired unit's pulverizers. Coal can be reclaimed from the open storage pile into the crusher house, so it can then proceed through the coal handling system. The coal handling system is equipped with dust collectors and there is the capacity for wet suppression on the open coal pile necessary to control fugitive emissions.

Ash Handling System – Both bottom and fly ash residual are created from the combustion of coal. Bottom ash falls to the bottom of the boiler where it is collected in the boiler ash hoppers. Fly ash is captured in the ESP, the economizer and the air heater and is collected in each of these places through a hopper system. The ash (bottom and fly) collected in each of these hoppers is then sluiced (via water jet system) to the ash treatment basin on site (a surface impoundment with a KPDES permitted outfall). Fly ash captured in the ESP can be collected by a dry ash handling system for beneficial reuse.

Gypsum Handling System - The primary byproduct of the FGD system will be gypsum. Gypsum can be a saleable product if it meets certain quality characteristics. It is anticipated that the gypsum will meet these quality standards; hence a new gypsum dewatering facility will be constructed at Brown. The gypsum slurry will be pumped from the FGD to the dewatering facility to be processed for off-site users. It will then be conveyed to a new exterior storage pile. A portion of the gypsum product may serve as beneficial re-use for the construction of the Brown ash pond. From the storage pile, the gypsum will be conveyed to a new truck loading station or onto an adjacent rail car loading station. In event the gypsum cannot be marketed, the gypsum will be conveyed to the on-site ash pond. Based on the entrained moisture in the gypsum, fugitive dust emissions from this process are anticipated to be nonexistent.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Natural Resources & Environmental Protection Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007N

Emissions, Stacks, and Controls Information

Applicant Name: Kentucky Utilities Company, Ghent   Log # E-997

SECTION I. Emissions Unit and Emission Point Information

KyEIS ID #	Emissions Unit and Emission Point Descriptions	Maximum Operating Parameters		Permitted Operating Parameters		
		Hourly Operating Rate (SCC Units/hr)	Annual Operating Hours (hrs/yr)	Hourly Operating Rate (SCC Units/hr)	Annual Operating Rate (SCC Units/yr)	Annual Operating Hours (hrs/yr)
21 167 00001	Emission Unit Name: **Indirect Heat Exchanger (Unit 3)** Date Constructed: Prior to July 19, 1971 HAPs present? ☑ Yes ☑ No	5300 MMBTU/Hr.	8,760	NA	NA	NA
		Note: "The max continuos rating of all E.W. Brown units combined is 8293 MMBtu (Unit 1 -1,260 MMBtu, Unit 2 - 1,733 MMBtu, Unit 3 -5,300 MMBtu)				
	Emission Point Name: **Unit 3 Boiler** Source ID: new stack 017 SCC Code: 10100212 SCC Units: lbs/MMBtu KyEIS Stack #: new stack 017 Fuel Ash Content: 13.8% (average) Fuel Sulfur Content: 3.80% Fuel Heat Content Ratio: 11,000 Btu/lb Applicable Regulations: 401 KAR 61:015; Regulation 7					
	Emission Point Name: Source ID: SCC Code: SCC Units: KyEIS Stack #: Fuel Ash Content: Fuel Sulfur Content: Fuel Heat Content Ratio: Applicable Regulations:					

Division Use Only: F___ Reviewer _________ Supervisor _________

DEP7007N
(continued)

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS ID #	Emission Factors			Control Equipment		Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
	Pollutant	Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equipment Association	Pollutant Overall Efficiency (%)	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
21 167 00001	See Attachment: Calculations of Emissions for Form 7007N)					See Attachment: Calculations of Emissions for Form 7007N)			See Attachment: Calculations of Emissions for Form 7007N)		
				1st control device	Electrostatic Precipitator						
				KyEIS Control ID #:							
				Collection efficiency:	99%						
				2nd control device	Low-Nox Burners						
				KyEIS Control ID #:							
				Collection efficiency:	50%						
				3rd control device	Wet Limestone Forced Oxidation SO_2 Scrubber						
				KyEIS Control ID #:							
				Collection efficiency:	98%	(manfacture's guarantee)					
				4th control device	Selective Catalytic Reduction with SO_3 Control						
				KyEIS Control ID #:							
				Collection efficiency:	85%	(manfacture's guarantee)					

SECTION II. Stack Information

KyEIS Stack ID #	Stack Description	Stack Physical Data			Stack Geographic Data			Stack Gas Stream Data		
		Height (ft)	Diameter (ft)	Vent Height (ft)	Vertical Coordinate	Horizontal Coordinate	Coordinate Collection Method Code	Flowrate (acfm)	Temperature (^oF)	Exit Velocity (ft/sec)
21 167 00001								approximate	approximate	approximate
017 (new stack)	Unit #3 Boiler	561	26.67	561	4,184,403.39	701,443.17	INI	2,176,962	129	65.0

Division Use Only: Reviewer ________ Supervisor ________

DEP7007N
(continued)

SECTION III. Control Equipment Information for Electrostatic Precipitator

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
102 4140 0001	*Electrostatic Precipitator (Unit 3/stack 017)* *(2 precipitators - 2 split precips operated in series)*	*Research-Cottrell Inc*	*Research-Cottrell Inc*	24-May-1905	*Unknown*

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
289 °F ______ °C	1,750,000	Unknown	Unknown	Unknown

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of ESP:
Pick one:
☑ Dry, negative corona
☐ Wet, negative corona
☐ Wet, positive corona

Dimensions of ESP (specify units):
Collection plate height 30 ft.
Length of collection plate in direction of gas flow 18 & 24 ft
ESP total width 72"1" ESP total height 37"10"

Number of stages:
2 +3 Sections in direction of gas flow; 2 + 2 section across gas flow; 4 + 6 total sections/94 + 114 gas passages

Number of plates per stage:
48 & 58

Particle migration (drift) velocity:	Particle resistivity:	Voltage across plates:
Unknown	Typically 1×10^{11} - 1×10^{11} ohm-cm	45 kV

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
0.5"	Particulate Matter	99.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
102 4140 0001	*Low NOx Burners (stack 017) for Units 3*	*ABB*	*LNCFS III*	*1992*	*Unknown*

Inlet Gas Stream Data

Temperature: NA °F ______ °C	Flowrate (scfm at 68°F): NA	Gas density (lb/ft^3): NA	Particle density (lb/ft^3) or Specific Gravity: NA	Average particle diameter (μm): *(or attach a particle size distribution table)* NA

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Low NOx burners with seperated over-fired air. 50% NOx control efficiency.

Equipment Operational Data

Pressure drop across unit (inches water gauge): NA	Pollutants collected/controlled: NOx	Pollutant removal/destruction efficiency (%): 50%

Division Use Only: Reviewer ________ Supervisor ________

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
102 4140 0001	*Selective Catalytic Reduction (Unit 3)*	*TBD*	*TBD (Custom built*	*2012*	*Estimated $186.5 million*

Inlet Gas Stream Data

Temperature: _____ °F _____ °C	Flowrate (scfm at 68°F): Unknown	Gas density (lb/ft^3): Unknown	Particle density (lb/ft^3) or Specific Gravity: Unknown	Average particle diameter (μm): *(or attach a particle size distribution table)* Unknown

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Equipment Operational Data

Pressure drop across unit (inches water gauge): Unknown	Pollutants collected/controlled: NOx	Pollutant removal/destruction efficiency (%): 85%

Division Use Only: Reviewer _________ Supervisor _________

Revision 6/00
May 20, 2009

DEP7007N
(continued)

SECTION III. Control Equipment Information for Scrubber

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
102 **4140** **0001**	*Wet Limestone Forced-Oxidation Sulfur Dioxide Scrubber (Unit 3 /Stack 017)*	*Fluor*	*Fluor (custom built)*	*5/1/2010 (Estimated startup date)*	*TBD*

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
330 °F ____ °C	Max guarantee: 1,933,765 (wet)	Unknown	Unknown	Unknown

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of scrubber:
☐ Venturi Throat type ____
☐ Packed bed Packing type ____ Packing height (inches) ____
☑ Spray tower Number of nozzles TBD Nozzle pressure (psig) TBD
☐ Other (specify) L/G ratio for all spray towers 130 gal/Kacf

Type of Flow:
☐ Concurrent
☑ Countercurrent
☐ Crossflow

Dimensions of scrubber:
Length in direction of gas flow TBD ft
Cross-sectional area TBD sq.ft
Venturi throat velocity TBD ft/s

Type of mist eliminator:
FRP with high temp flame resistant resin (vertical flow design)

Dimensions of mist eliminator:
Cross-sectional area TBD sq ft

Pressure drop across mist eliminator (in. H_2O):
designed to remove 99.5% of droplets > 40 microns

Chemical composition of scrubbing liquid:
Limestone Slurry

Scrubbing liquid flowrate: TBD gal/min
Fresh liquid makeup rate: TBD gal/min

Disposal method of scrubber effluent:
Oxidation to CaSO4 (gypsum), dewatered to 10% moisture, placed in on site landfill.

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
6.6	Sulfur Dioxide & Particulates	98% manufacture guarantee

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
102 4140 0001	*SO3 Mitigation (Stack 017) for Unit 3*	*To be determined*	*Custom Built*	*2012*	*TBD*

Inlet Gas Stream Data

Temperature: NA °F ______ °C	Flowrate (scfm at 68°F): NA	Gas density (lb/ft^3): NA	Particle density (lb/ft^3) or Specific Gravity: NA	Average particle diameter (μm): *(or attach a particle size distribution table)* NA

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Custom Design, See Drawing #06-664-D For a Conceptional Drawing

Equipment Operational Data

Pressure drop across unit (inches water gauge): NA	Pollutants collected/controlled: SO_3	Pollutant removal/destruction efficiency (%): To be determined

Division Use Only: Reviewer ________ Supervisor ________

7007N Form Supplement Table 2 (Section I Part 2)

EON Brown Station

		Emission Factors					Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
03	**1**	**Unit 3 Indirect Heat Exchanger**														
		CO	00630-08-0	0.500	lb/ton	AP42 1.1-3, 9/98	na	na	na	240.9	120.5	na	na	527.6	na	na
		NOX	10102-44-0	15.000	lb/ton	AP42 1.1-3, 9/98	C03A, C03B	LNB, SCR	92.5%	240.9	3,613.6	271.0	371	15,827.7	1,187.1	na
		PM	na	138.000	lb/ton	AP42 1.1-4, 9/98	C03C	ESP	99.5%	240.9	33,245.5	159.0	159	145,615.1	696.4	na
		PM10	na	31.740	lb/ton	AP42 1.1-4, 9/98	C03C	ESP	97.9%	240.9	7,646.5	159.0	na	33,491.5	696.4	na
		PM2.5	na	8.280	lb/ton	AP42 1.1-6, 9/98	C03C	ESP	96.5%	240.9	1,994.7	70.7	na	8,736.9	309.5	na
		SO2	07446-09-5	144.400	lb/ton	AP42 1.1-3, 9/98	C03D	FGD	98.0%	240.9	34,787.3	695.7	1,044	152,368.3	3,047.4	na
		VOC (TNMOC)	na	0.060	lb/ton	AP42 1.1-19, 9/98	na	na	na	240.9	14.5	na	na	63.3	na	na
		H2SO4	07664-93-9	6.625	lb/ton	3% conversion to SO3	C03D	FGD	86.2%	240.9	1,596.1	220.2	na	6,990.8	964.3	na
		Antimony	07440-36-0	2.24E-04	lb/ton	AP42 1.1-16, 9/98	C03C	ESP	96.5%	240.9	5.40E-02	1.86E-03	na	2.36E-01	8.17E-03	na
		Arsenic	07740-38-2	1.24E-02	lb/ton	AP42 1.1-16, 9/98	C03C	ESP	98.9%	240.9	2.98E+00	3.18E-02	na	1.31E+01	1.39E-01	na
		Beryllium	07440-41-7	2.50E-03	lb/ton	AP42 1.1-16, 9/98	C03C	ESP	99.7%	240.9	6.03E-01	1.69E-03	na	2.64E+00	7.41E-03	na
		Cadmium	07440-43-9	4.89E-04	lb/ton	AP42 1.1-16, 9/98	C03C	ESP	93.1%	240.9	1.18E-01	8.15E-03	na	5.16E-01	3.57E-02	na
		Chromium	07440-47-3	4.22E-03	lb/ton	AP42 1.1-16, 9/98	C03C	ESP	95.5%	240.9	1.02E+00	4.59E-02	na	4.46E+00	2.01E-01	na
		Cobalt	07440-48-4	2.05E-03	lb/ton	AP42 1.1-16, 9/98	C03C	ESP	97.5%	240.9	4.94E-01	1.24E-02	na	2.16E+00	5.42E-02	na
		Lead	07439-92-1	1.00E-02	lb/ton	AP42 1.1-16, 9/98	C03C	ESP	98.6%	240.9	2.41E+00	3.35E-02	na	1.06E+01	1.47E-01	na
		Manganese	07439-96-5	6.32E-03	lb/ton	AP42 1.1-16, 9/98	C03C	ESP	95.9%	240.9	1.52E+00	6.17E-02	na	6.67E+00	2.70E-01	na
		Nickel	07440-02-0	2.22E-03	lb/ton	AP42 1.1-16, 9/98	C03C	ESP	92.3%	240.9	5.34E-01	4.11E-02	na	2.34E+00	1.80E-01	na
		Magnesium	07439-95-4	6.00E-01	lb/ton	AP42 1.1-18, 9/98	C03C	ESP	98.2%	240.9	1.45E+02	2.65E+00	na	6.33E+02	1.16E+01	na
		Mercury	07439-97-6	3.00E-04	lb/ton	AP42 1.1-18, 9/98	C03C	ESP	72.3%	240.9	7.23E-02	2.00E-02	na	3.17E-01	8.76E-02	na
		Selenium	07782-49-2	4.00E-03	lb/ton	AP42 1.1-18, 9/98	C03C	ESP	67.5%	240.9	9.64E-01	3.13E-01	na	4.22E+00	1.37E+00	na
		Biphenyl	00092-52-4	1.70E-06	lb/ton	AP42 1.1-13, 9/98	na	na	na	240.9	4.10E-04	na	na	1.79E-03	na	na
		Naphthalene	00091-20-3	1.30E-05	lb/ton	AP42 1.1-13, 9/98	na	na	na	240.9	3.13E-03	na	na	1.37E-02	na	na
		Acetaldehyde	00075-07-0	7.04E-05	lb/ton	PISCES	na	na	na	240.9	1.70E-02	na	na	7.43E-02	na	na
		Acetophenone	00098-86-2	2.64E-05	lb/ton	PISCES	na	na	na	240.9	6.36E-03	na	na	2.79E-02	na	na
		Acrolein	00107-02-8	4.18E-05	lb/ton	PISCES	na	na	na	240.9	1.01E-02	na	na	4.41E-02	na	na
		Benzene	00071-43-2	8.58E-05	lb/ton	PISCES	na	na	na	240.9	2.07E-02	na	na	9.05E-02	na	na
		Benzyl chloride	00100-44-7	6.16E-06	lb/ton	PISCES	na	na	na	240.9	1.48E-03	na	na	6.50E-03	na	na
		Bis(2-ethylhexyl)phthalate	00117-81-7	7.92E-05	lb/ton	PISCES	na	na	na	240.9	1.91E-02	na	na	8.36E-02	na	na
		Bromoform	00075-25-2	3.90E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	9.40E-03	na	na	4.12E-02	na	na

7007N Form Supplement Table 2 (Section I Part 2)

EON Brown Station

KyEIS ID #	Process ID(s)	Emission Factors				Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
		Carbon disulfide	00075-15-0	2.42E-05 lb/ton	PISCES	na	na	na	240.9	5.83E-03	na	na	2.55E-02	na	na
		2-Chloroacetophenone	00532-27-4	7.00E-06 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	1.69E-03	na	na	7.39E-03	na	na
		Chlorobenzene	00108-90-7	3.52E-06 lb/ton	PISCES	na	na	na	240.9	8.48E-04	na	na	3.71E-03	na	na
		Chloroform	00067-66-3	1.76E-05 lb/ton	PISCES	na	na	na	240.9	4.24E-03	na	na	1.86E-02	na	na
		Cumene	00098-82-8	5.30E-06 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	1.28E-03	na	na	5.59E-03	na	na
		Cyanide	00057-12-5	2.50E-03 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	6.02E-01	na	na	2.64E+00	na	na
		Dimethyl sulfate	00077-78-1	4.80E-05 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	1.16E-02	na	na	5.06E-02	na	na
		2,4-Dinitrotoluene	00121-14-2	4.40E-06 lb/ton	PISCES	na	na	na	240.9	1.06E-03	na	na	4.64E-03	na	na
		Ethylbenzene	00100-41-4	1.76E-05 lb/ton	PISCES	na	na	na	240.9	4.24E-03	na	na	1.86E-02	na	na
		Ethyl chloride	00075-00-3	4.20E-05 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	1.01E-02	na	na	4.43E-02	na	na
		Ethylene dibromide	00106-93-4	1.20E-06 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	2.89E-04	na	na	1.27E-03	na	na
		Ethylene dichloride	00107-06-2	4.00E-05 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	9.64E-03	na	na	4.22E-02	na	na
		Formaldehyde	00050-00-0	5.72E-05 lb/ton	PISCES	na	na	na	240.9	1.38E-02	na	na	6.04E-02	na	na
		Hexane	00110-54-3	6.70E-05 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	1.61E-02	na	na	7.07E-02	na	na
		Isophorone	00078-59-1	2.64E-05 lb/ton	PISCES	na	na	na	240.9	6.36E-03	na	na	2.79E-02	na	na
		Methyl bromide	00074-83-9	1.60E-04 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	3.85E-02	na	na	1.69E-01	na	na
		Methyl chloride	00074-87-3	5.30E-04 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	1.28E-01	na	na	5.59E-01	na	na
		Methyl ethyl ketone	00078-93-3	3.90E-04 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	9.40E-02	na	na	4.12E-01	na	na
		Methyl hydrazine	00060-34-4	1.70E-04 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	4.10E-02	na	na	1.79E-01	na	na
		Methyl methacrylate	00080-62-6	2.00E-05 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	4.82E-03	na	na	2.11E-02	na	na
		Methyl tert butyl ether	01634-04-4	3.50E-05 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	8.43E-03	na	na	3.69E-02	na	na
		Methylene chloride	00075-09-2	7.92E-05 lb/ton	PISCES	na	na	na	240.9	1.91E-02	na	na	8.36E-02	na	na
		Phenol	00108-95-2	7.26E-05 lb/ton	PISCES	na	na	na	240.9	1.75E-02	na	na	7.66E-02	na	na
		Propionaldehyde	00123-38-6	4.18E-05 lb/ton	PISCES	na	na	na	240.9	1.01E-02	na	na	4.41E-02	na	na
		Styrene	00100-42-5	1.54E-05 lb/ton	PISCES	na	na	na	240.9	3.71E-03	na	na	1.62E-02	na	na
		Tetrachloroethylene	00127-18-4	9.24E-06 lb/ton	PISCES	na	na	na	240.9	2.23E-03	na	na	9.75E-03	na	na
		Toluene	00108-88-3	3.74E-05 lb/ton	PISCES	na	na	na	240.9	9.01E-03	na	na	3.95E-02	na	na
		1,1,1-Trichloroethane	00079-00-5	2.00E-05 lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	4.82E-03	na	na	2.11E-02	na	na
		Vinyl acetate	00108-05-4	6.82E-06 lb/ton	PISCES	na	na	na	240.9	1.64E-03	na	na	7.20E-03	na	na
		m/p-Xylene	00108-38-3	1.80E-05 lb/ton	PISCES	na	na	na	240.9	4.35E-03	na	na	1.90E-02	na	na
		o-Xylene	00095-47-6	9.68E-06 lb/ton	PISCES	na	na	na	240.9	2.33E-03	na	na	1.02E-02	na	na
		POM	na	5.28E-05 lb/ton	AP42 1.1-17, 9/98	na	na	na	240.9	1.27E-02	na	na	5.57E-02	na	na
		Hydrogen Chloride	07647-01-0	1.44E+00 lb/ton	PISCES	C03D	FGD	80.8%	240.9	346.9	66.4	na	1,519.3	291.0	na
		Hydrogen Fluoride	07664-39-3	1.68E-01 lb/ton	PISCES	C03D	FGD	86.9%	240.9	40.6	5.3	na	177.8	23.3	na

Commonwealth of Kentucky
Natural Resources & Environmental Protection Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007V

Applicable Requirements & Compliance Activities

APPLICANT NAME: Kentucky Utilities Company - E.W. Brown Generating Station

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
U3	Utility Boiler	PM	401 KAR 61:015 Section 4(4), Reg 7, & 2009 Consent Decree	0.254 lbs/ MMBtu based on 3-hr avg (Until Dec. 31, 2010) By Dec. 31, 2010 continuely operate ESP for Unit 3 to achieve a PM limit of not greater than 0.030 lb/MMBtu (based on 3-hr avg)	Annual performance test and PM CEM (once FGD & SCR are in operation) Note: Performance test must be completed prior to 12/31/10 to certify that PM emissions do not exceed 0.030 lb.MMBtu. PM CEM (within 180-days following commencement of operation of the FGD)
		SO2	401 KAR 61:015 Section 5(1), & 2009 Consent Decree	5.15 lbs/ MMBtu based on 24-hr avg Annual plant limit of 31,998 tons/yr for 2009 & 2010 Within 1 year from the commencement of operation of the SCR & once sufficient data is obtained: (1) 30-day rolling avg emission rate (2) 30-day rolling avg SO2 removal efficiency (3) Annual SO2 limitation of 2,300 for Unit 3 beginning with calendar year 2011 Shall install a FGD by Dec. 31, 2012	CEM & reporting
		NOx	401 KAR 61:015 Section 4(4), Reg 7, & 2009 Consent Decree	Annual plant limit of 4,072 tons/yr for 2009 - 2012 Continuely operate low NOx burners Beginning with calendar year 2009-2020. Plant must surrender to EPA or transfer to a non-profit 3rd party surplus Nox allowances within 60-days of the end of each calendar year (beginning March 1, 2010) 30-day rolling avg emission rate for NOx (once sufficient data is obtained) By Dec. 31, 2012 commence continuous operation of the SCR to maintain a 30-day rolling avg of no greater than 0.070 lb/MMBtu, except if flue gas temp does not allow use of the SCR. In that case, a max of 0.080 lb/MMBtu.	CEM & reporting
		Opacity	401 KAR 61:015 Section 4(4) & Reg 7	Emission shall not exceed 40% based on a 6-min avg, except that a max of 60% is allowed for a periods or aggregate of periods of not more than 60-min in any 60-minutes during building a new fire, cleaning a firebox, or blowing soot.	COM/Method 9
		SO3	2009 Consent Decree	Installed as part of SCR (PM control)	reporting
		Heat Rate	2009 Consent Decree	Heat rate limit of 5300 MMBtu/hr (federally enforceable)	reporting

DEP7007V
continued

APPLICANT NAME: Kentucky Utilities Company - E.W. Brown Generating Station

SECTION II. MONITORING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Monitored(7)	Description of Monitoring(8)
U3	Utility Boiler	PM	401 KAR 61:005	PM	Continuous Emissions Monitoring System shall comply with Regulation 401 KAR 61:005 PM CEM (within 180-days following commencement of operation of the FGD) Measure avg electrical output and min and max hourly generation rate daily (can be summarized as monthly averages in the semi-annual monitoring reports, if records are retained at facility). CAM plan if PM-CEM is out of compliance (ESP secondary voltage and current)
		SO2	401 KAR 61:005 401 KAR 61:015	SO2	Continuous Emissions Monitoring System shall comply with Regulation 401 KAR 61:005 measureing SO2 and oxygen or carbon dioxide Monitor sulfur content of solid fuel
		NOx	401 KAR 61:005	NOx	Continuous Emissions Monitoring System shall comply with Regulation 401 KAR 61:005 (NOx)
		Opacity	401 KAR 61:005	Opacity	Continuous Emissions Monitoring System shall comply with Regulation 401 KAR 61:005 (Opacity) Accept COM or within 30-minutes of 3rd consec exceedence, inspect the COM and/or control equipment, initiate repairs, perform Method 9, or documents why Method 9 can not be performed.
			Consent Decree	SO3	Records
			Consent Decree	Heat Rate	Monitor heat rate (records)
				Startup	Monitor duration of startup

DEP7007V
continued

APPLICANT NAME: Kentucky Utilities Company - E.W. Brown Generating Station

SECTION III. RECORDKEEPING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Recorded(9)	Description of Recordkeeping(10)
U3	Utility Boiler	PM	401 KAR 61:015		CEM & COM monitoring data; compliance tests; records regarding maint and operation (avg electrical output and min & max hourly generation rate) of ESP shall be maintained
		SO2	401 KAR 61:015		CEM monitoring data; records regarding maint and operation FGD shall be maintained
		NOx	401 KAR 61:015		CEM monitoring data; records regarding maint and operation of SCR shall be maintained
		Opacity	401 KAR 61:015		COM monitoring data and Method 9's
			Consent Decree	SO3 (part of SCR)	Regards regarding operation
			Consent Decree	Heat Rate	Heat rate data
				Fuel Analysis	Fuel Analysis & ash content
				Startup data	Records of duration of startups & type (cold, warm, hot)

DEP7007V
continued

APPLICANT NAME: Kentucky Utilities Company - E.W. Brown Generating Station

SECTION IV. REPORTING REQUIREMENTS

KYEIS No.[1]	Emission Unit Description[2]	Contaminant[3]	Origin of Requirement or Standard[4]	Parameter Reported[11]	Description of Reporting[12]
U3	Utility Boiler	PM	401 KAR 61:005	PM	Report to EPA, pursuant to Section XII (Periodic Reporting), the data record by the PM CEM for Unit 3, expressed in electronic format in lb/MMBtu on a 6-hr and 24-hr rolling basis. PM monitor Quarterly EDR reports
		SO2			Quarterly EDR reports
		NOx			Quarterly EDR reports
		Opacity			Testing data/method 9.
				SO3	
				Heat Rate	Quarterly EDR reports for heat rate
				Deviations	DEVIATIONS, Notify EPA in writing as soon as practicable , but no later than 21-days following the date of a malfucntion occurrent.
				Exceedences	Exceedences, startup, shutdown & malfunction reports;
				Reports	Semi-Annual monitoring reports, annual certifications, annual KYEIS emission surveys reports .
				Startup data	Reporting of type of startup (cold, warm, hot) and if duration exceeded manufacture's or historical durations

DEP7007V
continued

APPLICANT NAME: Kentucky Utilities Company - E.W. Brown Generating Station

SECTION V. TESTING REQUIREMENTS

KYEIS No.[1]	Emission Unit Description[2]	Contaminant[3]	Origin of Requirement or Standard[4]	Parameter Tested[13]	Description of Testing[14]
U3	Utility Boiler	PM	401 KAR 50:045; Consent Decree	PM	Annual (PM) stack test
		SO2			
		NOx			
		Opacity			Method 9 at least once every 14 boiler operating days, or more frequencly if requested by the Division. If Method 9's are unable to be perform, document the reason.
				SO3	
				Heat Rate	

Commonwealth of Kentucky
Natural Resources & Environmental Protection Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007DD

INSIGNIFICANT ACTIVITIES

INSIGNIFICANT ACTIVITY CRITERIA

1. Emissions from insignificant activities shall be counted toward the source's potential to emit;
2. Emissions from the activity shall not be subject to a federally enforceable requirement other than generally applicable requirements that apply to all activities and affected facilities such as 401 KAR 59:010, 61:020, 63:010, and others deemed generally applicable by the Cabinet;
3. The potential to emit a regulated air pollutant from the activity or affected facility shall not exceed 5 tons/yr.
4. The potential to emit of a hazardous air pollutant from the activity or affected facility shall not exceed 1,000 pounds/yr., or the deminimis level established under Section 112(g) of the Act, whichever is less;
5. The activity shall be included in the permit application, identifying generally applicable and state origin requirements.

Description of Activity Including Rated Capacity	Generally Applicable Regulations Or State Origin Requirements	Does the Activity meet the Insignificant Activity Criteria Listed Above?
Hydrated Lime Silos (for SO3 mitigation)	401 KAR 63:010	PTE < 5 tpy, HAP emissions < 1000 lb/yr
Note: The insignificant activities listed above are modifications or additions to the existing activities, noted on prior submittals		

SIGNATURE BLOCK

I, THE UNDERSIGNED, HEREBY CERTIFY UNDER PENALTY OF LAW, THAT I AM A RESPONSIBLE OFFICIAL, AND THAT I HAVE PERSONALLY EXAMINED, AND AM FAMILIAR WITH, THE INFORMATION SUBMITTED IN THIS DOCUMENT AND ALL ITS ATTACHMENTS. BASED ON MY INQUIRY OF THOSE INDIVIDUALS WITH PRIMARY RESPONSIBILITY FOR OBTAINING THE INFORMATION, I CERTIFY THAT THE INFORMATION IS ON KNOWLEDGE AND BELIEF, TRUE, ACCURATE, AND COMPLETE. I AM AWARE THAT THERE ARE SIGNIFICANT PENALTIES FOR SUBMITTING FALSE OR INCOMPLETE INFORMATION, INCLUDING THE POSSIBILITY OF FINE OR IMPRISONMENT.

BY Ralph Bowling
Authorized Signature

7 / 9 / 09
Date

Ralph Bowling
Typed or Printed Name of Signatory

V.P. Power Production
Title of Signatory

ATTACHMENT B

BSS - 2 BROWN COAL ANALYSIS

NOTE: Powder River Basin Coal will be fired at most in a 50% mixture with Bituminous Coal

	FGD Design Basis Spreadsheet	**Brown Station**		**Project Fuel Range**	
Coal Data Sheet	**Units**	**Design (Bituminous)**	**Powder River Basin**	**Min**	**Max**
Design Coal Name	Must be filled in	Design			
Coal Source:	Coal Mine				
Date Sample Taken:	Date				
Coal Ultimate Analysis	As Received	As Received	As Received		
Carbon (C)	Wt%	60.30	48.18	49.4	71.15
Hydrogen (H)	Wt%	4.50	3.50	3.33	5.90
Oxygen (O_2)	Wt%	6.80	12.00	0.95	19.40
Nitrogen (N_2)	Wt%	1.17	0.90	0.15	1.89
Sulfur (S)	Wt%	3.80	0.40	0.2	3.80
Chlorine (Cl)	Wt%	0.07	0.02	0.02	0.23
Fluorine (Fl)	Wt%	-		0.01	0.02
Moisture (Water H_2O)	Wt%	9.56	28.00	5.00	20.80
Ash	Wt%	13.80	7.00	5.00	30.00
	Total	100.00	100.00		
Wt. % Volatile	Wt%	33.00	36.00	26.00	50.00
Wt % Fixed Carbon	Wt%	42.00	30.00	30.00	42.00
Higher Heating Value	Btu/lb, As Recvd	11,000	8,500	9000	12800
Trace Elements - Coal - As Rec'd	**Typical**				
Coal Basin Name	-				
Silver	ppm			0.00	0.00
Arsenic	ppm	10		3.00	15.00
Boron	ppm			0.00	0.00
Barium	*ppm*	*50*		*30.00*	*125.00*
Beryllium	ppm			0.00	0.00
Bromine	ppm			0.00	0.00
Manganese	ppm			0.00	0.00
Nickel	ppm	15		0.00	0.00
Lead	ppm	10		5.00	40.00
Antimony	ppm	1		1.00	2.00
Selenium	ppm	2		1.00	4.00
Strontium	ppm	60		20.00	175.00
Cadmium	ppm	1		1.00	2.00
Cobalt	ppm			0.00	0.00
Chromium	ppm			10.00	75.00
Copper	ppm			0.00	0.00
Germanium	ppm			0.00	0.00
Mercury	ppm	0.15		0.10	0.25
Thalius	ppm			0.00	0.00
Uranium	ppm			0.00	0.00
Vanadium	ppm	40		30.00	175.00
Zinc	ppm	20		10.00	100.00
Fluorine	ppm	*80*		*50.00*	*200.00*
Chlorine	ppm	700		200.00	2500.00
Additional Trace Elements					
Magnesium	ppm	300		200.00	1500.00
	ppm			0.00	0.00
	ppm			0.00	0.00
	ppm			0.00	0.00
	ppm			0.00	0.00
Mineral Analysis from Coal					
SiO_2	Wt%	47.00		31.00	63.00
Al_2O_3	Wt%	20.00		15.00	50.00
TiO_2	Wt%	1.00		0.50	1.80
Fe_2O_3	Wt%	22.00		6.00	40.00
CaO	Wt%	3.25		0.47[2]	8.46
MgO	Wt%	0.96		0.50	1.44
Na_2O	Wt%	0.50		0.20	1.68
K_2O	Wt%	2.00		1.00	10.00
P_2O_5	Wt%	0.30		0.08	0.50
SO_3	Wt%	1.70		0.25	4.77
SrO	Wt%	0.10		0.01	0.20
BaO	Wt%	0.05		0.01	0.20
Mn_3O_4	Wt%	0.05		0.01	0.50

BSS - 2 BROWN COAL ANALYSIS

NOTE: Powder River Basin Coal will be fired at most in a 50% mixture with Bituminous Coal

	FGD Design Basis Spreadsheet	**Brown Station**		**Project Fuel Range**	
Coal Data Sheet	**Units**	**Design (Bituminous)**	**Powder River Basin**	**Min**	**Max**
NiO	Wt%	-		0.00	0.00
V_2O_5	Wt%	-		0.00	0.00
Undetermined	Wt%	0.35		0.10	0.50
Ash Analysis					
Economizer Outlet Hopper	Y/N				
Economizer Outlet Ash Conditions					
Date Sample Taken:	Date				
Size Distribution	Percent				
1/"2"	%			0.00	0.00
-1/2 + 3/8	%			0.00	0.00
-3/8 + 1/4	%			0.00	0.00
1/4 + #4 mesh	%			0.00	0.00
-4 + 8 mesh	%			0.00	0.00
-8 + 16 mesh	%			0.00	0.00
-16 + 30 mesh	%			0.00	0.00
-30 + 50 mesh	%			0.00	0.00
-50 + 100 mesh	%			0.00	0.00
-100 + 200 mesh	%			0.00	0.00
-200 + 325 mesh	%			0.00	0.00
-325 mesh	%			0.00	0.00
Mineral Analysis	Percent of Ash by Weight				
SiO_2	% by Wt			0.00	0.00
Al_2O_3	% by Wt			0.00	0.00
TiO_2	% by Wt			0.00	0.00
Fe_2O_3	% by Wt			0.00	0.00
CaO	% by Wt			0.00	0.00
MgO	% by Wt			0.00	0.00
K_2O	% by Wt			0.00	0.00
Na_2O	% by Wt			0.00	0.00
P_2O_5	% by Wt			0.00	0.00
MnO_2	% by Wt			0.00	0.00
SO_3	% by Wt			0.00	0.00
SrO	% by Wt			0.00	0.00
BaO	% by Wt			0.00	0.00
Mn_3O_4	% by Wt			0.00	0.00
NiO	% by Wt			0.00	0.00
V_2O_5	% by Wt			0.00	0.00
Undetermined	% by Wt			0.00	0.00
Additional Ash Minerals					
	% by Wt			0.00	0.00
	% by Wt			0.00	0.00
	% by Wt			0.00	0.00
	% by Wt			0.00	0.00
	% by Wt			0.00	0.00
Trace Elements					
Arsenic	ppm			0.00	0.00
Barium	ppm			0.00	0.00
Beryllium	ppm			0.00	0.00
Cadmium	ppm			0.00	0.00
Chromium	ppm			0.00	0.00
Copper	ppm			0.00	0.00
Lead	ppm			0.00	0.00
Mercury	ppm			0.00	0.00
Selenium	ppm			0.00	0.00
Silver	ppm			0.00	0.00
Iron	ppm			0.00	0.00
Manganese	ppm			0.00	0.00
Zinc	ppm			0.00	0.00
Boron	ppm			0.00	0.00
Aluminum	ppm			0.00	0.00
Vanadium	ppm			0.00	0.00

BSS - 2 BROWN COAL ANALYSIS

NOTE: Powder River Basin Coal will be fired at most in a 50% mixture with Bituminous Coal

	FGD Design Basis Spreadsheet	**Brown Station**		**Project Fuel Range**	
				Min	**Max**
Coal Data Sheet	**Units**	**Design (Bituminous)**	**Powder River Basin**		
Additional Ash Trace Elements					
	ppm			0.00	0.00
	ppm			0.00	0.00
	ppm			0.00	0.00
	ppm			0.00	0.00
	ppm			0.00	0.00
Other Information					
Carbon	% Weight			0.00	0.00
Hydrogen	% Weight			0.00	0.00
Ph				0.00	0.00
ESP First Hopper					
Date Sample Taken:	Date				
Size Distribution	Percent				
1/"2"	%			0.00	0.00
-1/2 + 3/8	%			0.00	0.00
-3/8 + 1/4	%			0.00	0.00
1/4 + #4 mesh	%			0.00	0.00
-4 + 8 mesh	%			0.00	0.00
-8 + 16 mesh	%			0.00	0.00
-16 + 30 mesh	%			0.00	0.00
-30 + 50 mesh	%			0.00	0.00
-50 + 100 mesh	%			0.00	0.00
-100 + 200 mesh	%			0.00	0.00
-200 + 325 mesh	%			0.00	0.00
-325 mesh	%			0.00	0.00
Mineral Analysis	Percent of Ash by Weight				
SiO_2	% by Wt			0.00	0.00
Al_2O_3	% by Wt			0.00	0.00
TiO_2	% by Wt			0.00	0.00
Fe_2O_3	% by Wt			0.00	0.00
CaO	% by Wt			0.00	0.00
MgO	% by Wt			0.00	0.00
K_2O	% by Wt			0.00	0.00
Na_2O	% by Wt			0.00	0.00
P_2O_5	% by Wt			0.00	0.00
MnO_2	% by Wt			0.00	0.00
SO_3	% by Wt			0.00	0.00
SrO	% by Wt			0.00	0.00
BaO	% by Wt			0.00	0.00
Mn_3O_4	% by Wt			0.00	0.00
NiO	% by Wt			0.00	0.00
V_2O_5	% by Wt			0.00	0.00
Undetermined	% by Wt			0.00	0.00
Additional ESP Ash Minerals					
	% by Wt			0.00	0.00
	% by Wt			0.00	0.00
	% by Wt			0.00	0.00
	% by Wt			0.00	0.00
	% by Wt			0.00	0.00
Trace Elements					
Arsenic	ppm			0.00	0.00
Barium	ppm			0.00	0.00
Beryllium	ppm			0.00	0.00
Cadmium	ppm			0.00	0.00
Chromium	ppm			0.00	0.00
Copper	ppm			0.00	0.00
Lead	ppm			0.00	0.00
Mercury	ppm			0.00	0.00
Selenium	ppm			0.00	0.00
Silver	ppm			0.00	0.00
Iron	ppm			0.00	0.00

BSS - 2 BROWN COAL ANALYSIS

NOTE: Powder River Basin Coal will be fired at most in a 50% mixture with Bituminous Coal

	FGD Design Basis Spreadsheet	**Brown Station**		**Project Fuel Range**	
Coal Data Sheet	**Units**	**Design (Bituminous)**	**Powder River Basin**	**Min**	**Max**
Manganese	ppm			0.00	0.00
Zinc	ppm			0.00	0.00
Boron	ppm			0.00	0.00
Aluminum	ppm			0.00	0.00
Vanadium	ppm			0.00	0.00
Additional ESP Ash Trace Elements					
	ppm			0.00	0.00
	ppm			0.00	0.00
	ppm			0.00	0.00
	ppm			0.00	0.00
	ppm			0.00	0.00
Other Information					
Carbon	% Weight			0.00	0.00
Hydrogen	% Weight			0.00	0.00
Ph				0.00	0.00

ATTACHMENT C

SELECTIVE CATALYTIC REDUCTION SYSTEM

A selective catalytic reduction (SCR) system to control concentrations of NO_x generated by the combustion of coal will be installed on E.W. Brown Unit 3

Anhydrous ammonia will be use in the SCR system.

Flue gas containing ammonia and NO_x undergoes an exothermic reduction reaction as it passes through the catalyst, forming nitrogen and water vapor. The following are the predominant reactions that take place:

$$4NO + 4NH_3 + O_2 \xrightarrow{\text{Catalyst}} 4N_2 + 6H_2O + heat \uparrow$$

$$2NO_2 + 4NH_3 + O_2 \xrightarrow{\text{Catalyst}} 3N_2 + 6H_2O + heat \uparrow$$

The catalyst reactor shall be located in a temperature zone of the boiler where the catalyst will be most effective at all loads and ambient temperatures.

The ammonia injection grid shall be located upstream of the SCR reactor in a zone where gas or surface temperatures do not exceed 800° F. The injection grid shall be designed and arranged to ensure uniform mixing of the ammonia and the exhaust gas stream.

Anhydrous ammonia vaporizing and dilution equipment will be provided with the SCR system. Dilution air shall be introduced by a centrifugal blower and measured by an orifice. Auxiliary steam will be used to heat the dilution air. The anhydrous ammonia feed shall be filtered, measured, and injected into a vaporizer unit. The ammonia shall contact the heated dilution air in an evaporator. The ammonia injection equipment shall include dilution air fans, dilution air heaters, liquid ammonia mass flow meter, flow control valve, piping, instruments, and all other required accessories. The ammonia shall be diluted and mixed with conveying air prior to injection into the flue gas stream.

Multiple layers of catalyst will be provided. Typical layers are two to three, with a potential fourth layer left open for addition at a later time to allow catalyst life to be optimized.

Soot blowers or sonic horns will be used to periodically clean ash off of the catalyst.

The injection grid shall be designed with multiple injection branches or shall use static mixers in the duct to mix the flue gas and ammonia prior to reaching the catalyst.

The rate of ammonia injection shall be determined from the inlet NO_x concentration and the signal proportion to gas flow, based on the preset NH_3/NO_x molar ration and the desired target NO_x concentration. The rate of ammonia injection shall be adjusted upward in the outlet NO_x concentration exceeds the target NO_x emission rate.

During startup, injection of ammonia shall automatically be initiated when the following condition has been met:

> The flue gas temperature at the outlet of the SCR catalyst is at SCR operating conditions.

The ammonia flow shall be stopped under any of the following conditions:

> The ratio of ammonia and dilution airflow signals is greater than the maximum value specified.
>
> Leaks are detected in the ammonia storage or ammonia distribution areas by external ammonia leak detectors.
>
> SCR outlet temperatures fall below the minimum required temperature of the catalyst and SCR vendors.

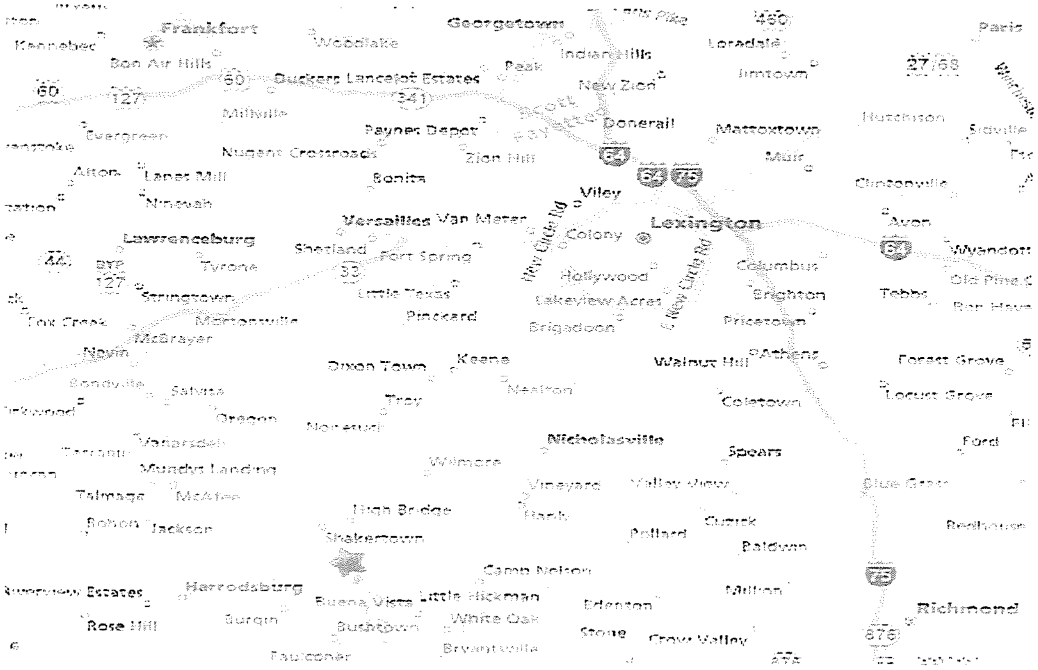
The truck unloading system shall be designed for safe transfer of anhydrous ammonia reagent from the truck, to the ammonia storage tanks and return of displaced ammonia vapor to the unloading vehicle. The ammonia storage tank(s) shall be designed for safe storage of anhydrous ammonia reagent.

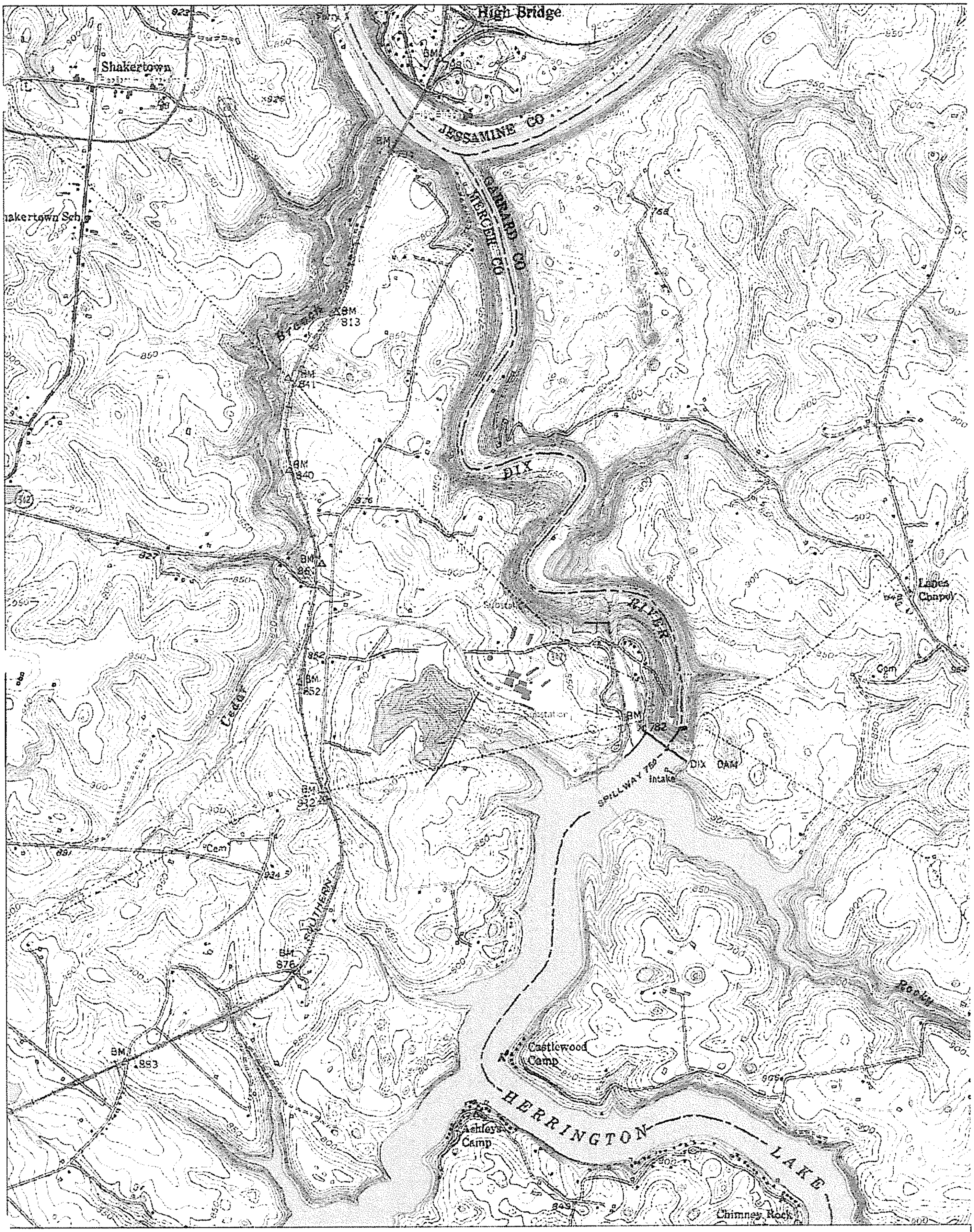
SO3 Mitigation

Hydrated lime or Trona (sodium based sorbent) will be injected (dry injection) before and/or after the ESP. These sorbents react with the flue gas to form solid compounds. The solid compounds are removed in the ESP with additional removal in the WFGD. KU will use a dry injection technique, which will use pneumatic conveying equipment to transport dry solids from the storage silo to the flue gas stream. Attachment D contains a flow diagram of a typical SO3 mitigation system.

ATTACHMENT D

KU's E. W. Brown Station is located approximately 25 miles southwest of Lexington, Kentucky, jus northeast of the town of Harrodsburg, Kentucky as indicated on the map below.





DeLORME

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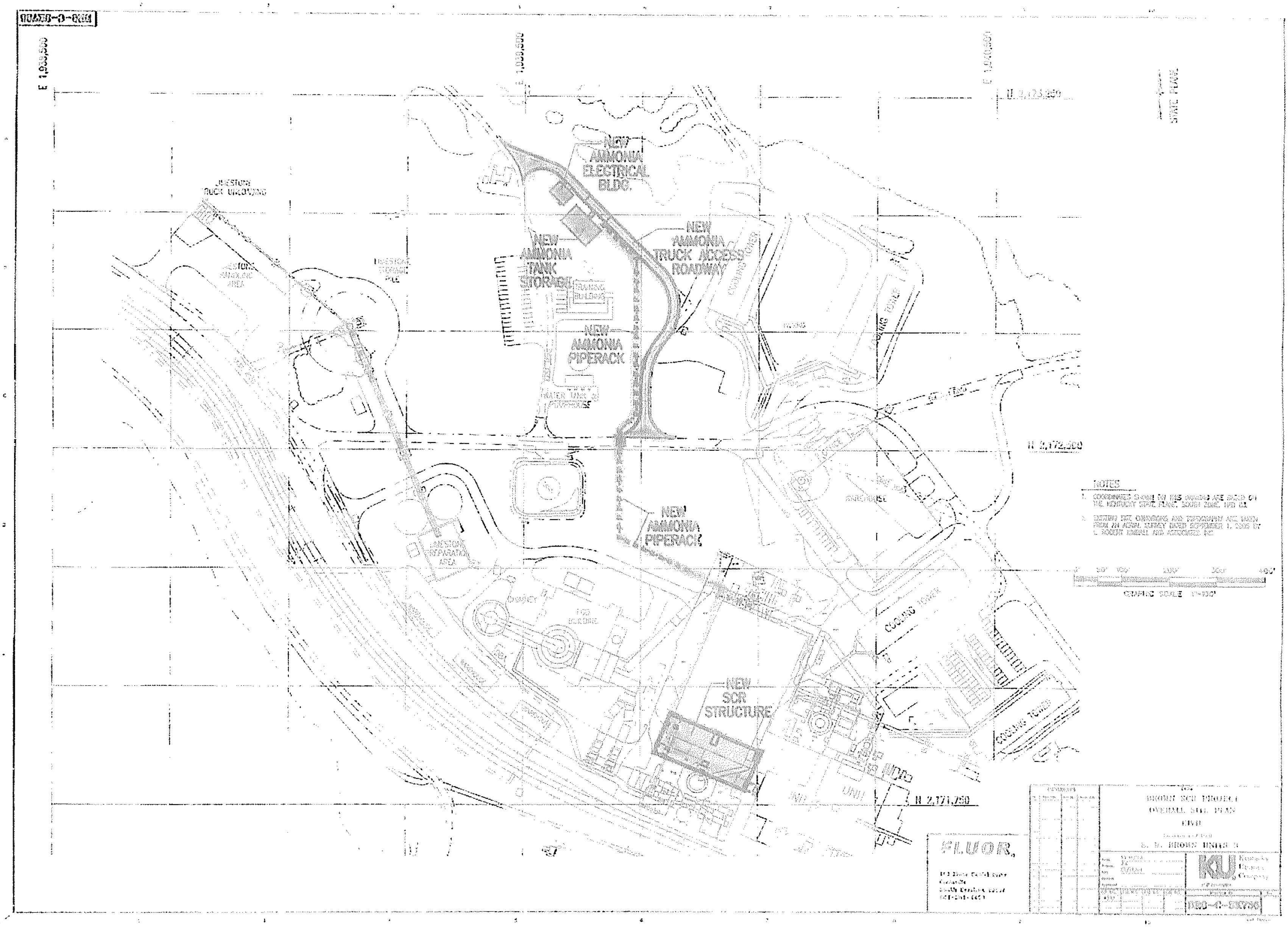
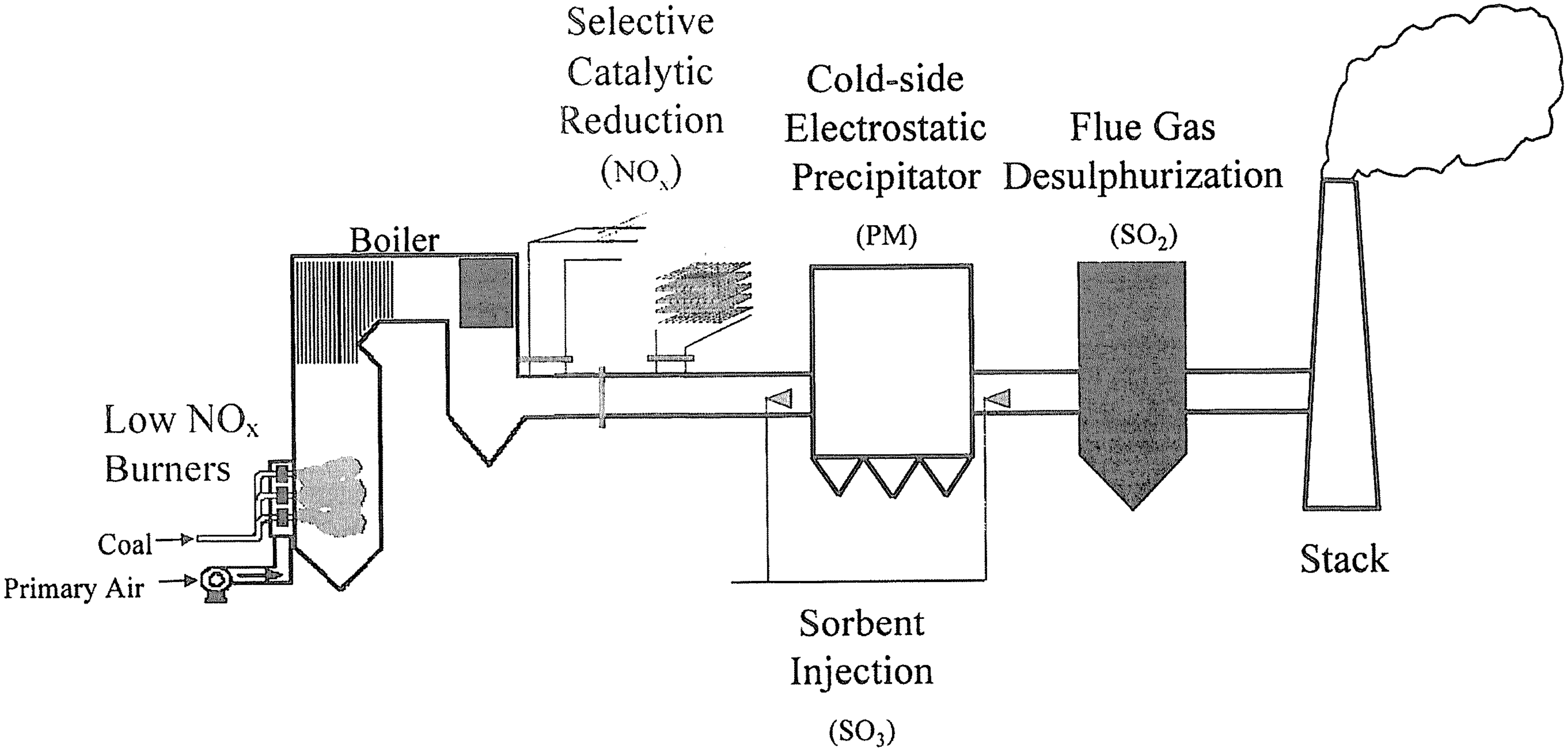
Zoom Level: 13-0 Datum: WGS84

Scale 1 : 25,000

E.W. Brown Station - Kentucky Utilities Co
Mercer County, Harrodsburg, Kentucky
USGS Wilmore Quadrangle Map

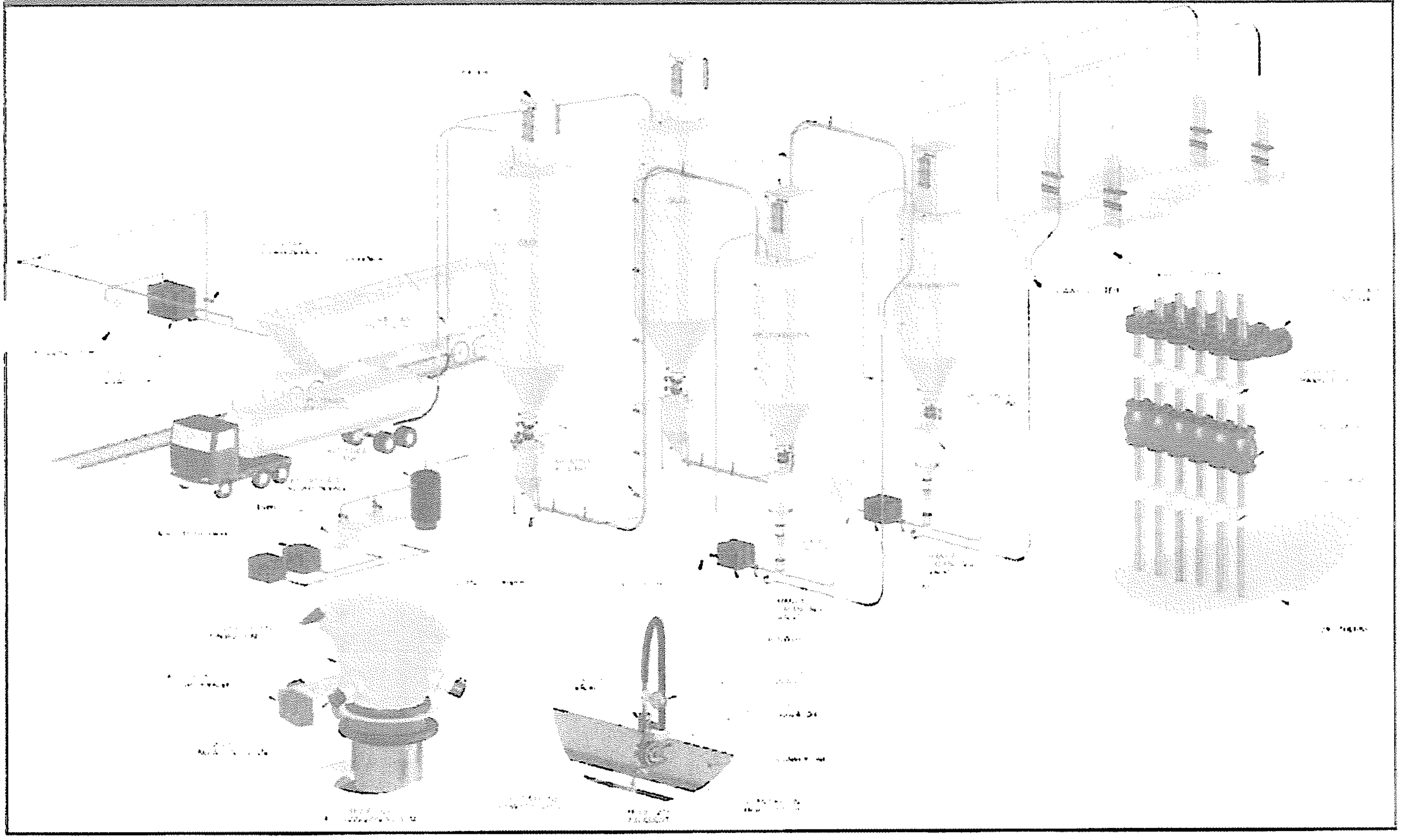

DBO-C-00700
E 1,938,500
E 1,939,500
E 1,940,500
N 2,173,250
N 2,172,500
N 2,171,750
STATE PLANE
NEW AMMONIA ELECTRICAL BLDG.
NEW AMMONIA TRUCK ACCESS ROADWAY
NEW AMMONIA TANK STORAGE
TRAINING BUILDING
NEW AMMONIA PIPERACK
WATER TANK
NEW AMMONIA PIPERACK
NEW SCR STRUCTURE
LIMESTONE TRUCK UNLOADING
LIMESTONE STORAGE PILE
LIMESTONE STORAGE AREA
LIMESTONE SEPARATION AREA
FGD BUILDING
CHIMNEY
COOLING TOWER
COOLING TOWER
COOLING TOWER
WAREHOUSE
UNIT
NOTES
1. COORDINATES SHOWN ON THIS DRAWING ARE BASED ON THE KENTUCKY STATE PLANE, SOUTH ZONE, NAD 83.
2. EXISTING SITE CONDITIONS AND TOPOGRAPHY ARE TAKEN FROM AN AERIAL SURVEY DATED SEPTEMBER 1, 2005 BY L. ROBERT KIMBALL AND ASSOCIATES, INC.
0' 50' 100' 200' 300' 400'
GRAPHIC SCALE 1"=100'
FLUOR.
BROWN SCR PROJECT
OVERALL SITE PLAN
CIVIL
E. W. BROWN UNIT 3
KU Kentucky Utilities Company
DBO-C-00700



Emission Control Technologies

SO3 Mitigation System - Typical Process Flow from Nol-tec

TYPICAL PROCESS FLOW



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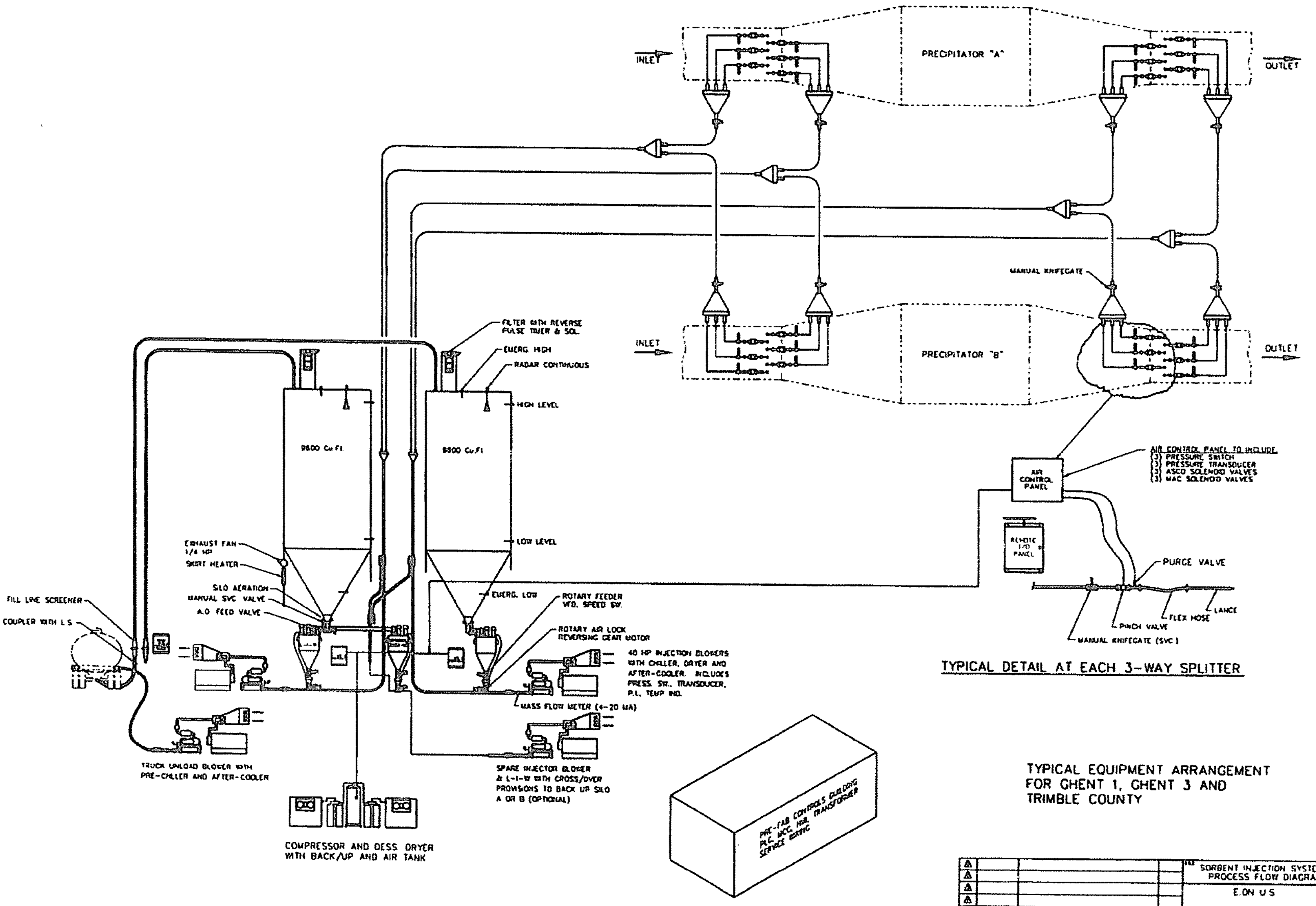
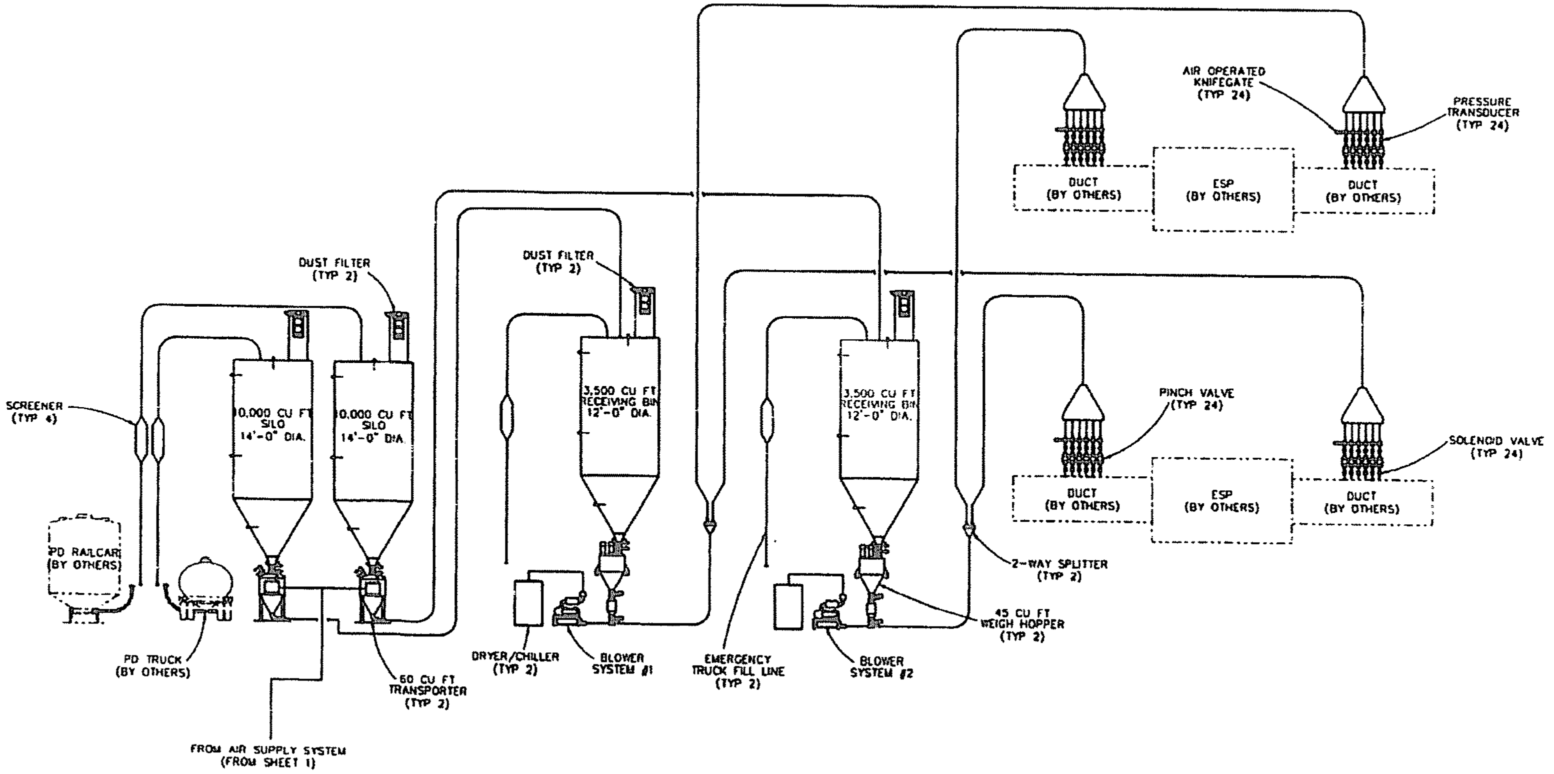
NOL-TEC SYSTEMS



TYPICAL DETAIL AT EACH 3-WAY SPLITTER

TYPICAL EQUIPMENT ARRANGEMENT
FOR GHENT 1, GHENT 3 AND
TRIMBLE COUNTY

SORBENT INJECTION SYSTEM
PROCESS FLOW DIAGRAM
E.ON U.S
LTS
16FEB07
N.T.S.
KOL-TEC SYSTEMS, Inc.
06-664-D
1/1



BOILER #3

TRONA/LIME CONVEYING
& INJECTION SYSTEM

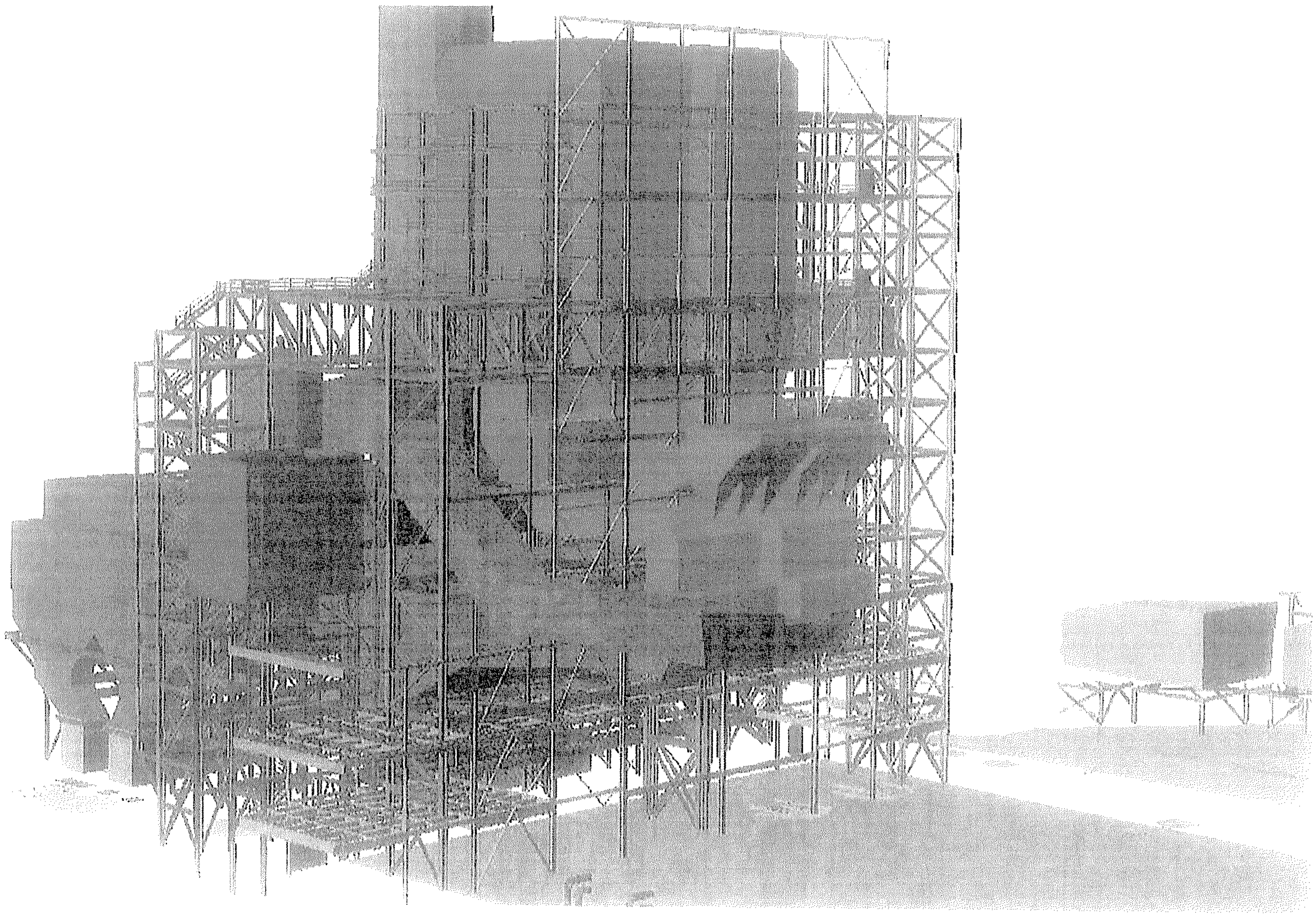
E-ON
GHENT, KY.

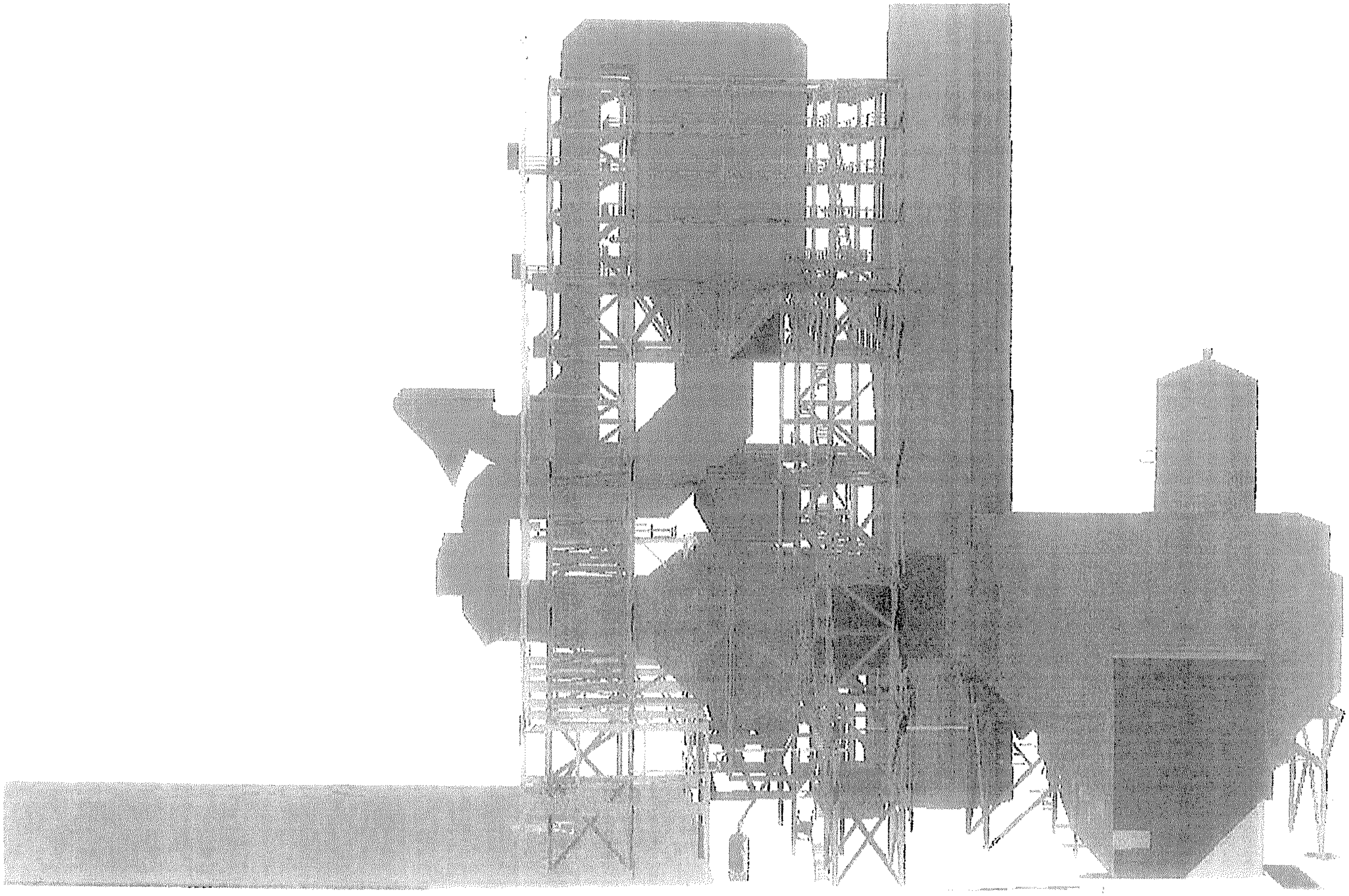
LTS
10NOV06
3/32"=1'-0"

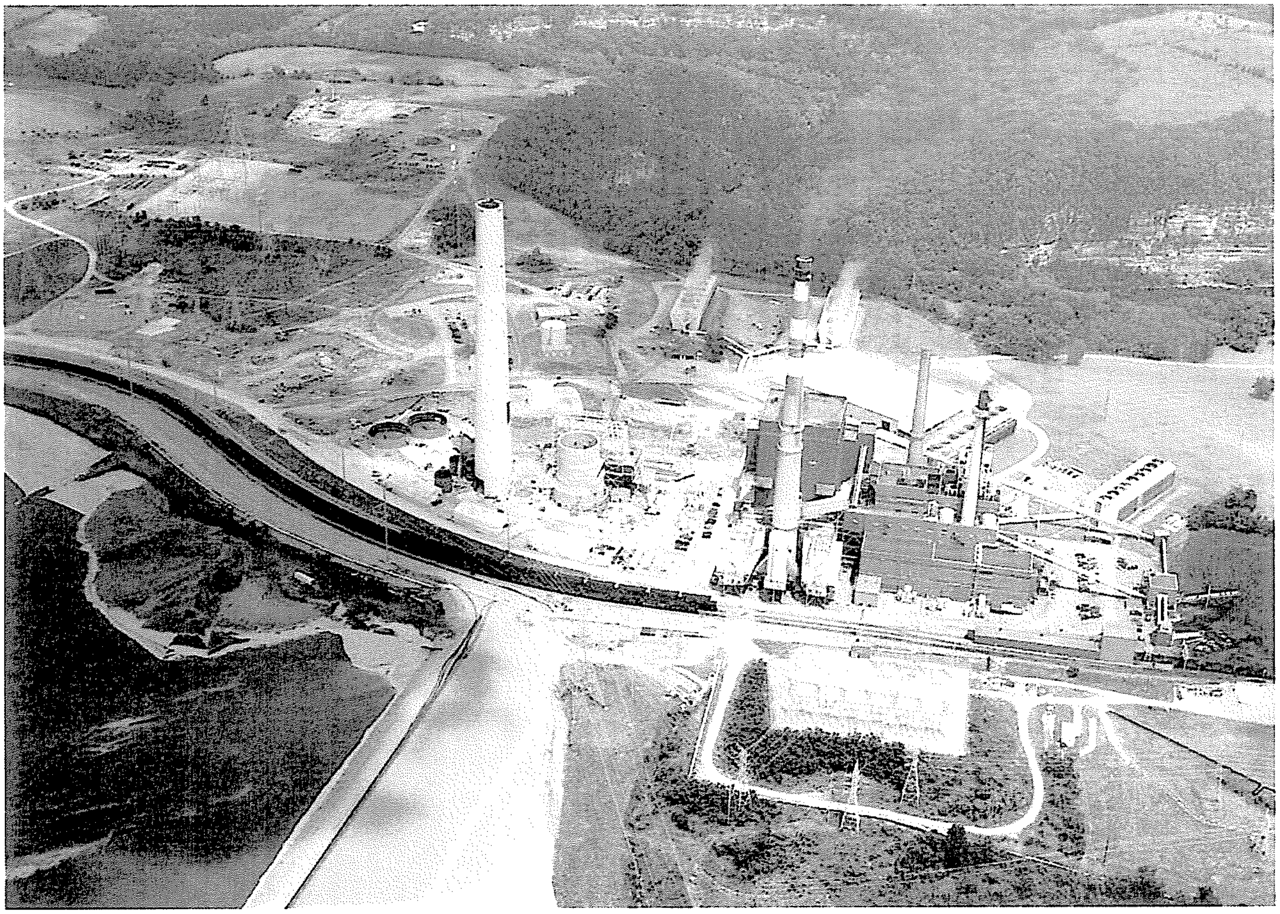
NOL-TEC SYSTEMS, INC.

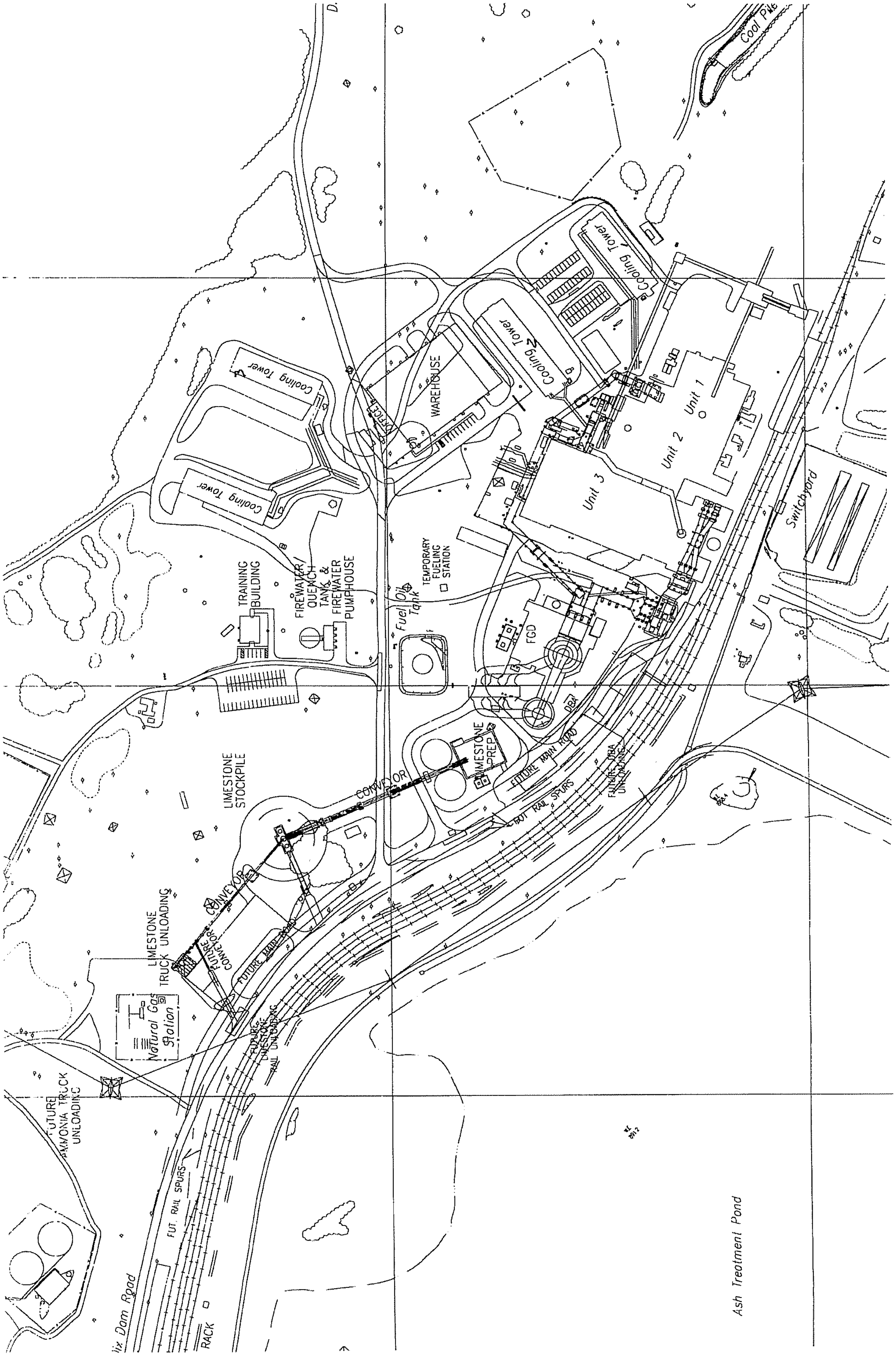
06-664-0

2 3








Coal Pile
Cooling Tower
Cooling Tower
Cooling Tower
Cooling Tower
Unit 1
Unit 2
Unit 3
WAREHOUSE
OFFICE
Switchyard
TEMPORARY FUELING STATION
Fuel Oil Tank
FGD
DBA
LIMESTONE PREP
FUTURE MAIN ROAD
FUT RAIL SPURS
FUTURE DBA UNLOADING
CONVEYOR
LIMESTONE STOCKPILE
TRAINING BUILDING
FIREWATER/ QUENCH TANK & FIREWATER PUMPHOUSE
CONVEYOR
LIMESTONE TRUCK UNLOADING
FUTURE CONVEYOR
FUTURE MAIN ROAD
Natural Gas Station
FUTURE LIMESTONE RAIL UNLOADING
FUTURE AMMONIA TRUCK UNLOADING
FUT. RAIL SPURS
ix Dam Road
RACK
Ash Treatment Pond

ATTACHMENT E

Attachment E - PSD baseline and Post Change H_2SO_4 Calculations

Calculation Assumptions:

1. 100% of sulfur is oxidized in the boiler, 1% converted to SO_3 initially (no SCR): Source: Sargent and Lundy Final Report dated March 29, 2006.
2. Across the SCR, 2% of the SO_2 is converted to SO_3. Typical SO_2 to SO_3 conversion rate for 2 layers of high conversion rate catalyst. Source: Sargent and Lundy Final Report dated March 29, 2006.
3. With no sorbent injection, assume 5% SO_3 is removed in air heater and 5% removed in the DESP.
4. Use actual sulfur % by year (1.41-1.59% sulfur) for low sulfur coal. Source: Annual KYEIS (Emission Inventories).
5. Use 3.8% sulfur for high sulfur coal value. This is the design value for the wet FGD system.
6. SO_3 FGD control efficiency assumed to be 50% (start is May 2010). Source: Vendor design guarantee.
7. Molecular weight ratio used to determine SO_3, and H_2SO_4 emissions.
8. Forecasted fuel burned and operating hours source: E.ON U.S. Generation Planning Department.

Note: Some columns hidden to shorten the 24-month rolling annual average to fit on one page.

Note: Some columns hidden to shorten the 24-month rolling annual average to fit on one page.

Step 1: Calculate Baseline Emissions

Calculate baseline H_2SO_4 emissions using current date (March 2009) and looking back 5 years. Start data in March 2002 to calculate a rolling 24-month annual average starting in March 2004.

Calculation of SO_3: (Coal tons X sulfur% X production rate of SO_3 X molecular weight ratio X control efficiency of air heater X control efficiency of ESP). Where max coal tons = max coal flow rate (481,818 lb/hr) X

Example calculation of SO_3: (27,053 X 1.58% X 1% X (80.0642/32.065)*0.95*0.95) - calculation for March 2003

Year	2002										2003									2007				2009	
Month	March	April	May	June	July	August	September	October	November	December	January	February	March	April	May	September	October	November	December	January	February	March	April	March	
Unit 3 Coal Burned Tons	106507	98522	73495	103484	110904	94620	91297	9	30719	90718	117794	82468	27053	100754	103109	74,361	88,529	86,669	83,544	86,743	99,494	75,523	0	91,916	
Monthly SO_3 tons	33.84	31.30	23.35	32.88	35.24	30.06	29.01	0.00	9.76	28.82	41.94	29.36	9.63	35.87	36.71	25.97	30.92	30.27	29.18	30.10	34.53	26.21	0.00	32.73	Max
Rolling 24-month Annual Tons	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	263.83	263.55	272.06	268.53	266.07	267.26	262.65	258.25	373.51	373.51

SO_3 Baseline Tons 373.5 **H_2SO_4 Baseline Tons** 457.6

Rolling average calculation of Black & Veatch "BACT" Data (H_2SO_4 tons/yr)

Calculate H_2SO_4 emissions with FGD and SCR operation (without SO_3 mitigation) using maximum coal usage (see B&V data Section 3.0) and 75% capacity factor.

Calculation of SO_3: (max coal tons X sulfur% X SO_3 production rate X molecular weight ratio X control efficiency of FGD X control efficiency of air heater X control efficiency of ESP X 75% capacity factor)

Example calculation of SO_3: (175,864 X 3.8% X 3% X (80.0642/32.065)*0.5*0.95*0.95*0.75) calculation for January 2013

Year	2013												2014								2017	
Month	January	February	March	April	May	June	July	August	September	October	November	December	January	February	March	July	August	September	October	November	December	
Unit 3 Coal Burned Tons	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	175,864	
Monthly SO_3 tons	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	169.42	Max
Rolling 24-month Annual Tons	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2033.05	2033.05	2033.05	2033.05	2033.05	2033.05	2033.05

SO_3 tons after SCR operation 2,033.0 **H_2SO_4 tons after SCR operation** 2,490.5

Step 2. Determine if PSD significance level is exceeded after project is initiated (SCR Operation). Note: same calculation as above except using "expected" coal usage and no capacity factor adjustment.
Calculate emissions with FGD and SCR operation (without SO_3 mitigation) and compare to baseline H_2SO_4 + 7 tons allowed

Calculation of SO_3: (expected coal tons X sulfur% X SO_3 production rate X molecular weight ratio X control efficiency of FGD X control efficiency of air heater X control efficiency of ESP)

Example calculation of SO_3: (124,052 X 3.5% X 3% X (80.0642/32.065)*0.5*0.95*0.95) calculation for January 2013

Year	2013											
Month	January	February	March	April	May	June	July	August	September	October	November	December
Unit 3 Coal Burned Tons	124,052	114,098	116,360	25,869	110,033	109,069	117,578	117,349	109,084	106,384	109,294	119,670
Monthly SO_3 tons	159.34	146.56	149.46	33.23	141.34	140.10	151.03	150.73	140.12	136.65	140.39	153.71
Rolling 24-month Annual Tons	0	0	0	0	0	0	0	0	0	0	0	0

Year	2014							2017	
Month	January	February	March	July	August	September	October	November	December	
Unit 3 Coal Burned Tons	124,811	117,393	77,178	117,678	115,715	110,959	120,057	117,101	122,642	
Monthly SO_3 tons	160.32	150.79	99.13	151.16	148.63	142.52	154.21	150.41	157.53	Max
Rolling 24-month Annual Tons	0	0	0	1636.99	1636.75	1639.44	1646.61	1653.22	1653.53	1677.76

SO_3 tons after SCR operation 1,677.8 H_2SO_4 tons after SCR operation 2,055.2

Note: Some columns hidden to
shorten the 24-month rolling
annual average to fit on one page.

Step 3. Calculate maximum projected emissions after SCR operation, with SO_3 mitigation
Calculate rolling 24-month annual average of H_2SO_4:

Calculation of SO_3: (expected coal tons X sulfur% X SO_3 production rate X molecular weight ratio X control efficiency of FGD X control efficiency of air heater X control efficiency of ESP X control efficiency of SO3 mitigation system)

Example calculation of SO_3: (124,052 X 3.8% X 3% X (80.064/32.065)*0.5*0.95*0.95*0.2904) calculation for January 2013

Year	2013											
Month	January	February	March	April	May	June	July	August	September	October	November	December
Unit 3 Coal Burned Tons	124,052	114,098	116,360	25,869	110,033	109,069	117,578	117,349	109,084	106,384	109,294	119,670
Monthly SO_3 tons	46.27	42.56	43.40	9.65	41.04	40.68	43.86	43.77	40.69	39.68	40.77	44.64
Rolling 24-month Annual Tons	0	0	0	0	0	0	0	0	0	0	0	0

Year	2014							2017	
Month	January	February	March	July	August	September	October	November	December	
Unit 3 Coal Burned Tons	124811.4	117392.6	77177.9	117677.8	115715	110958.5	120056.7	117100.9	122642	
Monthly SO_3 tons	46.56	43.79	28.79	43.90	43.16	41.39	44.78	43.68	45.75	Max
Rolling 24-month Annual Tons	0	0	0	475.38	475.31	476.09	478.18	480.10	480.19	487.22

SO_3 tons after SCR operation 487.2 H_2SO_4 tons after SCR operation 596.8

Potential To Emit (PTE) calculation:	
5,300	Max boiler heat input (mmBtu/hr); per CD
8,760	PTE hours/year
11,000	Coal higher heating value (Btu/lb)
2,110,363.6	PTE Coal Tons (Max heat input X Max Hours / Heating Value
3.0%	SO3 production rate
5,421.5	SO_3 PTE Uncontrolled Tons
787.2	SO_3 PTE Controlled Tons (FGD + Sorbent Injection)
1,237.8	SO_3 PTE Uncontrolled lb/hr
179.7	SO_3 PTE Controlled lb/hr (FGD + Sorbent Injection)
6,641.2	H_2SO_4 PTE Uncontrolled Tons
964.3	H_2SO_4 PTE Controlled Tons (FGD + Sorbent Injection)
1,516.3	H_2SO_4 PTE Uncontrolled lb/hr
220.2	**H_2SO_4 PTE Controlled lb/hr (FGD + Sorbent Injection)**

Example: SO3 Uncontrolled Tons Potential To Emit (PTE) calculation: PTE coal tons X sulfur % X SO3 production rate X molecular weight ratio X control efficiency of air heater X control efficiency of ESP

Baseline Period H_2SO_4 lb/hr Calculation	**Maximum Projected H_2SO_4 lb/hr Calculation**	
457.6	596.8	H_2SO_4 tons
7994.4	7,888.0	*Operating Hours
2000	2,000	Conversion
114.5	151.3	H_2SO_4 "Annual Average" lb/hr
		*Lowest annual expected hours from 2013 through 2017

Attachment E - PSD Baseline and Projected Post-Change NOx Calculations

Calculation Assumptions:
1. Forecasted fuel heat input source: E.ON U.S. Generation Planning Department.
2. NOx emission rate after SCR operation is based on meeting 0.07 lb/mmBtu per Consent Decree times the projected monthly heat input (mmBtu).
3. NOx emissions (tons) during baseline period based on annual average lb/mmBtu rate times the average monthly heat input (mmBtu).

Note: Some columns hidden to shorten the 24-month rolling annual average to fit on one page.

Note: Some columns hidden to shorten the 24-month rolling annual average to fit on one page.

Step 1: Calculate Baseline Emissions
Calculate baseline NOx emissions using current date (March 2009) and looking back 5 years. Start data in March 2002 to calculate rolling 24-month average starting in March 2004.

Calculation of NOx: (Monthly Coal mmBtu X NOx Emission Factor)/2000
Example calculation of NOx: (685,480 mmBtu X 0.36 lb/mmBtu)/2000 - calculation for March 2003

Year	2002										2003	
Month	March	April	May	June	July	August	September	October	November	December	January	February
Unit 3 Coal Burned Tons	2560002	2396055	1776227	2480718	2664133	2288291	2184738	216	733570	2170157	2864632	2004895
Monthly NOx tons	494.08	462.44	342.81	478.78	514.18	441.64	421.65	0.04	141.58	418.84	515.63	360.88
Rolling 24-month Annual Tons	0	0	0	0	0	0	0	0	0	0	0	0

Year											2007			2009	
Month	March	April	April	May	June	July	August	September	October	November	January	February	March	March	
Unit 3 Coal Burned Tons	685,480	2533291	2036253	387695	1460182	1735777	2348933	1805188	2156035	2128764	2130408	2478396	1864663	1,984,959	
Monthly NOx tons	123.39	455.99	335.98	63.97	240.93	286.40	387.57	297.86	355.75	351.25	338.73	394.06	296.48	335.46	Max
Rolling 24-month Annual Tons	0	0	3071.61	2932.30	2904.87	2879.81	2906.36	2918.67	2963.49	2973.14	2988.70	3017.27	2979.07	3985.84	4356.30

NOx Baseline Tons 4,356.3

Note: Some columns hidden to shorten the 24-month rolling annual average to fit on one page.

Step 2. Calculate NOx emissions after SCR in operation
Calculate emissions after SCR operation and compare to NOx baseline

Calculation of NOx: (Monthly Coal mmBtu X NOx Emission Factor)/2000
Example calculation of NOx: (2,778,759 mmBtu X 0.07 lb/mmBtu)/2000 - calculation for January 2013

Year	2013											
Month	January	February	March	April	May	June	July	August	September	October	November	December
Unit 3 Coal Burned mmBtu	2778759	2555785	2606474	579471	2464737	2443155	2633735	2628608	2443484	2383011	2448182	2680613
Monthly NOx tons	97.26	89.45	91.23	20.28	86.27	85.51	92.18	92.00	85.52	83.41	85.69	93.82
Rolling 24-month Annual Tons	0	0	0	0	0	0	0	0	0	0	0	0

Year	2014											2017	
Month	January	February	February	March	April	May	June	July	August	September	November	December	
Unit 3 Coal Burned mmBtu	2795775	2629595	2570197	2529359	588614	2433672	2323302	2635983	2592016	2485471	2623059	2747181	
Monthly NOx tons	97.85	92.04	89.96	88.53	20.60	85.18	81.32	92.26	90.72	86.99	91.81	96.15	Max
Rolling 24-month Annual Tons	0	0	997.87	1024.04	999.46	1000.23	999.14	999.16	999.01	1000.65	1009.07	1009.25	1024.04

NOx tons after SCR operation 1,024.0

Baseline Period NOx lb/hr	**Post-Project NOx lb/hr Calculatio**	
4356.3	1,024.0	NOx tons
8197.6	7,888.0	*Operating Hours
2000	2,000	Conversion
1,062.8	259.6	"Annual Average" NOx lb/hr
		*Lowest annual expected hours from 2013 through 2017

ATTACHMENT F

Product Name:	HYDRATED LIME (continued)

Toxicity:	LD_{50} oral (rat) for calcium hydroxide is 7340 mg/kg. This product is not listed by MSHA, OSHA, or IARC as a carcinogen, but this product may contain crystalline silica, which has been classified by IARC as (Group I) carcinogenic to humans when inhaled in the form of quartz or cristobalite. No reported Carcinogenicity, Reproductive Effects, Teratogenicity or Mutagenicity.
Exposure Limits:	Refer to section 8.
Irritancy:	Can cause severe irritation of eyes, skin, respiratory tract and gastrointestinal tract.
Chronic Exposure:	Inhalation of silica can cause a chronic lung disorder, silicosis.

Alkaline substance that increases pH to a maximum of 12.4 in a saturated water solution at 25°C
Calcium hydroxide gradually reacts with CO_2 in air to form calcium carbonate ($CaCO_3$)
Calcium carbonate is ecologically neutral
Uncontrolled spillage in surface waters should be avoided since the increase pH could be detrimental to fish
Harmful to aquatic life in high concentration

Dispose according to federal, provincial/state and local environmental regulations.

Classification:	TDG	Not listed for ground transportation
	HMR	Not listed for ground transportation

TDG: Transportation of Dangerous Goods Regulation (CAN)
HMR: Hazardous Materials Regulation (USA)

Exposure Limits:	Calcium hydroxide: 15 mg/m^3 (OSHA-total); 5 mg/m^3 (OSHA – resp); 5 mg/m^3 (ACGIH, O. Reg. 833) Silica (crystalline quartz): 10 mg/m^3 (total dust); 3.3 mg/m^3 (respirable) (OSHA); 0.05 mg/m^3 (respirable - ACGIH); 0.1 mg/m^3 (O. Reg. 845)
Engineering Controls:	Use ventilation and dust collection to control exposure to below applicable limits.
Respiratory Protection:	Wear NIOSH N-95 Dust Mask.
Eye Protection:	Eye protection (chemical goggles, safety glasses and/or face shield) should be worn where there is a risk of hydrated lime exposure. Contact lenses should not be worn when working with lime products
Hand Protection:	Use clean dry gloves
Skin Protection:	Cover body with suitable clothes (long sleeves shirts and trousers). Use over the ankle waterproof caustic resistant footwear
	Refer to Ontario Regulation 845: Designated Substance – Silica.

Physical State:	Solid
Odor & Appearance:	Odorless, white powder
pH:	12.4 in saturated water solution at 25°C
Melting point:	580°C
Boiling point:	2850°C
Vapor pressure:	Non volatile
Vapor density:	Non volatile
Density:	2.24 g/cc
Solubility:	Slightly soluble in water: 0.2% @ 0° C Soluble in acids, glycerin and sugar solutions

Stability:	Stable products, not very soluble.
Decomposition temperature:	580°C, forms calcium oxide (CaO) and water
Reactivity:	Reacts with acids to form calcium salts while generating heat. Reacts with carbon dioxide in air to form calcium carbonate.
Conditions to avoid:	Vicinity of incompatible materials
Incompatible materials:	Acids; reactive fluoridated, brominated or phosphorous compounds; aluminum (may form hydrogen gas), reactive powdered metals; organic acid anhydrides; nitro-organic compounds; interhalogenated compounds
Hazardous decomposition products:	Calcium oxide (CaO)

Product Name:	HYDRATED LIME (continued)

Flash point:	Non-flammable
Autoignition temperature:	Non-flammable
Inflammability limits:	None
Explosion risk:	None by itself, but heat produced by reaction with strong acids can generate steam and pressure
Hazardous combustion products:	Decomposes to produce calcium oxide (CaO), which can react with water to produce steam and pressure
Extinguishing media:	Use dry chemical fire extinguisher. Do not use water or halogenated compounds, except that large amounts of water may be used to deluge small quantities of hydrated lime. Use appropriate extinguishing media for surrounding fire conditions.
Fire fighting instructions:	Keep personnel away from and upwind of fire. Wear full fire-fighting turn-out gear (full Bunker gear), and respiratory protection (self-contained breathing apparatus).

Individual and collective precautions:	Avoid creating conditions which release dust – use mechanical ventilation to remove dust from work spaces
Avoid inhalation of dust:	Wear respiratory protection - minimum NIOSH N-95 Dust Mask
Cleaning methods for spills:	Use personal protective equipment (eyes, skin and inhalation, see Section 8). Use dry methods (vacuuming, sweeping) to collect spilled materials. Avoid generating dust. For large spills, evacuate area downwind of clean-up area operations to minimize dust exposure. For small spills, store spilled materials in dry, sealed plastic or metal containers. Dust residue on surfaces may be washed with water.
Precautions for the protection of the environment:	May not be released into surface waters without controls (increases pH)
Waste Disposal:	Dispose according to federal, provincial/state and local environmental regulations

Handling:	In open air or in ventilated places, avoid skin and eye contact, avoid creating airborne dust
Storage:	Store in dry places sheltered from humidity. Keep away from acids and incompatible substances Keep out of reach of children

Product Name:	HYDRATED LIME (continued)

Overview: Hydrated lime is an odorless white or grayish-white granular powder. Contact can cause irritation to eyes, skin, respiratory system, and gastrointestinal tract. Contact may aggravate disorders of eyes, skin, gastrointestinal tract, and respiratory system.

Eyes: Can cause severe irritation or burning of eyes, including permanent damage.

Skin: Can cause severe irritation or burning of skin, especially in the presence of moisture.

Ingestion: Can cause severe irritation or burning of gastrointestinal tract if swallowed.

Inhalation: Can cause severe irritation of the respiratory system. Long-term exposure may cause permanent damage. Hydrated lime is not listed by MSHA, OSHA, or IARC as a carcinogen, but this product may contain crystalline quartz silica, which has been classified by IARC as (Group I) carcinogenic to humans when inhaled. Inhalation of silica can also cause a chronic lung disorder, silicosis.

Irritant: Eyes, mucous membranes, moist skin, respiratory tract.

Flammability: This product is not flammable or combustible

Explosive: This product is not explosive in dust form

Reactivity: May react violently with strong acids producing heat and possible steam explosion in confined space

Symbols: WHMIS Symbol: "E" Corrosive Material; "D2A" Materials causing other toxic effects

Health Effects:

Inhalation: Acute: irritation, sore throat, cough, sneezing. Chronic: persistent coughing and breathing problems. Long-term exposure to silica can cause a chronic lung disorder, silicosis.

Eyes: Acute: severe irritation, intense tearing, burns. Chronic: possible blindness when exposure is prolonged.

Skin: Acute: removes natural skin oils, blotches, itching and superficial burns in case of sweating. Chronic: no known effects.

Ingestion: Acute: sore throat, stomach aches, cramps, diarrhea, vomiting. Chronic: no known effects.

Treatments:

Inhalation: Move victim to fresh air. Seek medical attention if necessary. If breathing has stopped, give artificial respiration.

Eyes: Immediately flush eyes with large amounts of water for at least 15 minutes. Pull back the eyelid to make sure all the lime dust has been washed out. Seek medical attention immediately. Do not rub eyes.

Skin: Flush exposed area with large amounts of water. Seek medical attention immediately.

Ingestion: Give large quantities of water or fruit juice. Do not induce vomiting. Seed medical attention immediately. Never give anything by mouth if victim is rapidly losing consciousness or is unconscious or convulsing.

CARMEUSE
NATURAL CHEMICALS

Carmeuse North America
11 Stanwix Street, 11th Floor
Pittsburgh, PA 15222
Phone: 412-995-5500
Fax: 412-995-5594

Date of Origin:	06/05/ 02
Date of Revision:	12/06/04
Revision No	7

Material Safety Data Sheet

Product Name:	HYDRATED LIME

INFOTRAC: 800-535-5053 [In case of an emergency call this number 24 HOURS a day 7 DAYS a week.]

[illegible]

1.1. Identification of the substance:

Chemical name:	Calcium hydroxide
Product name(s):	Hydrated Lime, Industrial Hydrate
Formula:	$Ca(OH)_2$
CAS #:	1305-62-0
Molecular Weight:	74.08
Material Uses:	Water treatment, steel flux, caustic agent, pH adjustment, acid gas absorption, construction

1.2. Company:

Main Office:
Carmeuse North America
11 Stanwix Street, 11th Floor
Pittsburgh, PA 15222
Telephone: 412-995-5500
Fax: 412-995-5594

Canadian Office:
Carmeuse Lime (Canada) Limited
P.O. Box 190
Ingersoll, Ontario N5C 3K5
Telephone: 519-423-6283
Fax: 519-423-6545

[illegible]

Ingredient	% by Weight	CAS #	Exposure Limits
Calcium hydroxide	>85	1305-62-0	OSHA PEL: 15 mg/m^3 (total), 5 mg/m^3 (resp) ACGIH TLV: 5 mg/m^3 O. Reg. 833 TWAEV: 5 mg/m^3 LD_{50} oral (rat) 7340 mg/kg
Silica - crystalline quartz	<1	14808-60-7	OSHA PEL*: 10 mg/m^3 (total dust); 3.3 mg/m^3 (respirable) ACGIH TLV: 0.05 mg/m^3 (respirable) O. Reg. 845: 0.1 mg/m^3

*PEL (total dust) = (30 mg/m^3) / (% silica + 2) ; PEL (respirable) = (10 mg/m^3) / (% silica + 2)

CARMEUSE
NATURAL CHEMICALS

Carmeuse Lime
Black River Operation
9043 Highway 154
Butler, KY 41006

PRODUCT INFORMATION

Product Description:	FGD Hydrated Lime – Hi Cal
Product Code:	007
Production Facility:	Black River
Packaging:	Bulk only

Typical Properties: Chemical

	Average (%)
Calcium Hydroxide	94.00
Free Moisture	< 3.0

Typical Properties: Physical

	Average (%)
BET Surface Area (m^2/gram)	20
Bulk Density ($\#/ft^3$)	32
Size (at point of loading)	
- Passing 325 mesh	93.7

The information contained in this product information sheet is, to the best of our knowledge, true and accurate, but any typical values given are subject to occasional variations based on variations in the raw material inputs and processing operations. Each user is advised to evaluate the product (specific compositions, physical properties and performance characteristics) independently for suitability in the intended use.

Product Name:	HYDRATED LIME (continued)

Symbol:	WHMIS RATING D2A, E NFPA RATING HEALTH – 2 SPECIFIC HAZARD - ALK FLASH POINTS – 0 REACTIVITY – 1 HMIS RATING HEALTH –2 SPECIFIC HAZARD - ALK FLASH POINTS – 0 REACTIVITY – 1
Risk Phrases:	Risk of serious damage to the eyes Keep out of reach of children
Safety Phrases:	Keep storage container away from humidity Avoid contact with skin and eyes. In case of contact with eyes, rinse immediately with water for at least 15 minutes
CPR (Canada):	This product has been classified in accordance with the hazard criteria of the Controlled Products Regulation (CPR) of Canada and this MSDS contains all information required by the CPR.

Hydrated lime can be removed from objects (such as vehicles) using rags dampened with dilute vinegar. After applying dilute vinegar, vehicles (especially chrome surfaces) must be washed with water.

ATTACHMENT G

Compliance Assurance Monitoring (CAM) Plan
Kentucky Utilities/E.W. Brown Generating Station Unit 3

Introduction

CAM applies at Title V major sources that use control devices to achieve compliance with an applicable limit or standard and have potential pre-control emissions greater than or equal to 100% of the major source trigger for the pollutant.

Kentucky Utilities (KU) E.W. Brown Generating Station is requesting a PSD permit modification for Unit 3, which will trigger the following control devices to become subject to the CAM requirements as part of the PSD permit application request.

- Emission Unit 03 (Unit 3 Indirect Heat Exchanger) currently employs an electrostatic precipitator (ESP) for particulate matter (PM) control. A wet limestone flue gas desulfurization system (WFGD) for sulfur dioxide (SO_2) control is currently under construction, and a selective catalytic reduction (SCR) for nitrogen oxide (NOx) control which will include a SO3 mitigation system for sulfuric acid mist (H2SO4) control will be installed prior to December 31, 2012.

The Compliance Assurance Monitoring Plans (1-4) are provided below:

May 20, 2009

(1) Compliance Assurance Monitoring Plan – Particulate Matter for Emission Units 3

Emissions Unit

Facility:	E.W. Brown Generating Station
Description:	Units 3 Indirect Heat Exchangers
Identification:	Emission Unit 03, Emission Point 017 (after WFGD is installed)

Applicable Regulations, Emission Limit, and Monitoring Requirements

Applicable Regulations:	Emission Unit 03: 401 KAR 61:015 and Regulation No. 7
Regulated Pollutant:	Particulate Matter (PM)
Emission Limits:	Emission Unit 03: 0.254 lb/MMBtu based on a 3-hr avg (existing) 0.030 lb/MMBtu based on a 3-hr avg (after WFGD, but no later than 12/31/10)

Monitoring Requirements: Visible emissions (opacity), periodic testing for particulate matter

Control Technology

Electrostatic precipitator (ESP)

Monitoring Approach

The E.W. Brown Generating Station Emission Unit 03 (emission point 017) will use a PM Continuous Emission Monitor (CEM) as its CAM for PM. The data reporting system for the PM CEM will continuously measure particulate matter and will calculate particulate matter emission rates in terms of lb/MMBtu based on a three-hour average and compare this to the applicable emission limit.

Justification

PM CEM

The use of a Continuous Emission Monitoring System that provides results in units of the standard for the pollutant of interest and meets the criteria in 40 CFR Part 64.3 (d)(2) is considered presumptively acceptable CAM.

(2) Compliance Assurance Monitoring Plan – SO_2 for Emission Unit 3

Emissions Unit

Facility:	E.W. Brown Generating Station
Description:	Unit 3 Indirect Heat Exchanger
Identification:	Emission Unit 03; Emission Point 017 (after WFGD is installed)

Applicable Regulations, Emission Limit, and Monitoring Requirements

Applicable Regulations:	401 KAR 61:015
Regulated Pollutant:	sulfur dioxide (SO_2)
Emission Limits:	5.15 lb/MMBtu based on a 24-hour average (existing) 0.100 lb/MMBtu based on a 30-day rolling avg (with WFGD) Emission Unit 03 has SO_2 allocations per the Acid Rain program.
Monitoring Requirements:	40 CFR Part 75 Continuous Emission Monitoring (CEMs)

Control Technology

Wet limestone forced-oxidation sulfur dioxide scrubber on Emission Unit 03.

Monitoring Approach

The E.W. Brown Generating Station Emission Unit 03 will use 40 CFR Part 75 CEMS to continuously measure sulfur dioxide on the generating unit. The data reporting system for the CEMS will calculate sulfur dioxide emission rates in terms of lb/MMBtu based on a 30-day rolling average and compare to the applicable limit.

Justification

The use of a Continuous Emission Monitoring System that provides results in units of the standard for the pollutant of interest and meets the criteria in 40 CFR Part 64.3 (d)(2) is considered presumptively acceptable CAM.

(3) Compliance Assurance Monitoring Plan – NOx for Emission Unit 3

Emissions Unit

Facility:	E.W. Brown Generating Station
Description:	Unit 3 Indirect Heat Exchanger

Identification: Emission Unit 03 Emission Point 017 (after WFGD is installed)

Applicable Regulations, Emission Limit and Monitoring Requirements

Applicable Regulations:	40 CFR Part 75
Regulated Pollutant:	Nitrogen Oxides (NOx)
Emission Limits:	Emission Units 03 has an emission limit of 0.70 lb/MMBtu based on a thirty-day rolling average, except a limit of 0.080 lb/MMBtu based on a thirty-day rolling average applies if the gas temperature is too low to safely operate the SCR,.
Monitoring Requirements:	40 CFR Part 75 CEMS

Control Technology

Selective Catalytic Reduction (SCR) for Emission Units 03 and Low NOx Burners (CAM is not applicable to Low NOx Burners).

Monitoring Approach

The E.W. Brown Generating Station Emission Units 03 will use the 40 CFR Part 75 CEMS to continuously measure NOx on the generating units. The data reporting system for the CEMS will calculate NOx emission rates in terms of lb/MMBtu based on a thirty-day rolling average for the Emission Unit.

Justification

The use of a Continuous Emission Monitoring System that provides results in units of the standard for the pollutant of interest and meets the criteria in 40 CFR Part 64.3 (d)(2) is presumptively acceptable CAM.

(4) Compliance Assurance Monitoring Plan – Sulfuric Acid Mist (H_2SO_4) for Unit 3

KU proposes to control sulfuric acid mist (H_2SO_4) emissions from Unit 3 with a SO3 mitigation system.

LG&E proposes to conduct initial stack tests to verify that when SO_2 is at its permitted emission limit, sulfuric acid mist is at or below its permitted emission limit. Once it can be verified that whenever SO_2 is in compliance, sulfuric acid mist is in compliance, SO_2 will be used as a surrogate for sulfuric acid mist emissions.

ATTACHMENT H

H_2SO_4 AIR DISPERSION MODELING ANALYSIS AND RISK ASSESSMENT
E.ON E.W. BROWN STATION ▪ HARRODSBURG, KENTUCKY

Prepared for:

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Project 091801.0025

June 2, 2009

KU
an e·on company

Trinity
Consultants

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1. INTRODUCTION

E.ON U.S. (E.ON) owns and operates a power generation facility, the EW Brown Station, just east of Harrodsburg, Kentucky on the western shore of Lake Herrington. The facility consists of three coal-fired utility boilers as well as natural-gas-fired turbines, and hydroelectric capacity derived from Dix Dam. The Brown Station is submitting an air permit application for plant modifications involving the installation of a Selective Catalytic Reduction (SCR) control system on Unit 3. Due to the increased oxidation of sulfur to SO_3 in the flue gas caused by the SCR system, while emissions of NO_X will be substantially reduced, the project will result in collateral increases in H_2SO_4 emissions out the stack.

The Kentucky Division of Air Quality (KDAQ) may request that an air dispersion modeling analysis be completed as part of a permit action pursuant to 401 KAR 63:020 when there is an increase in air pollutant emissions associated with new construction or modifications at a facility that is deemed to be significant. This is done so that there is a documented basis for affirming that a facility does not cause an adverse impact, as required by 401 KAR 63:020. To proactively demonstrate that the increased levels of H_2SO_4 emissions would not cause adverse ambient impacts, an air dispersion modeling analysis has been conducted for inclusion with the air permit application. This refined modeling employed a refined treatment of buildings, locations, terrain, meteorology, land use, and dispersion algorithms. Both the maximum short-term and annual ambient impacts of H_2SO_4 are compared with health-based reference concentrations found under other national or state health based programs.

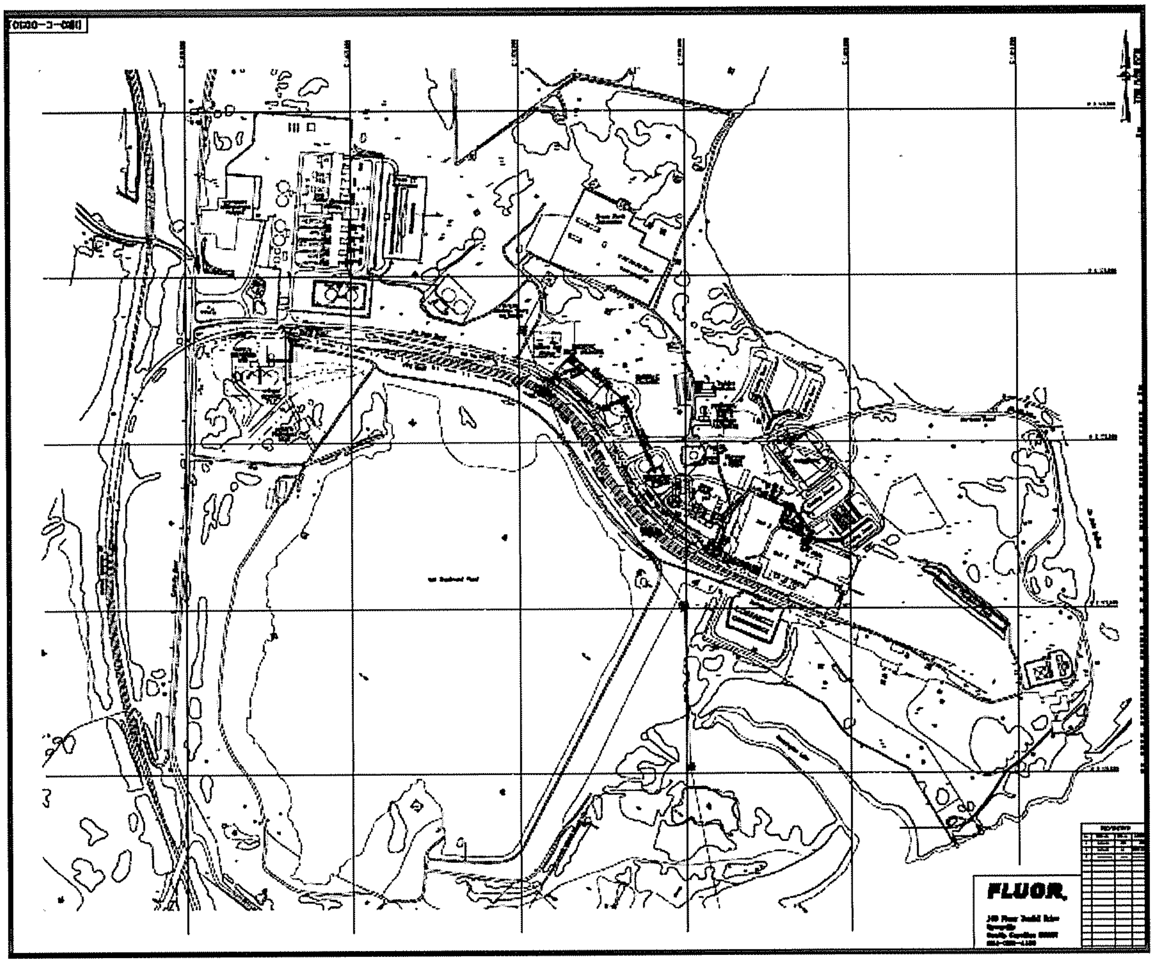
2.1 FACILITY LOCATION AND AREA MAPS

The Brown Station is located approximately nine (9) miles east northeast of Harrodsburg, Kentucky along the west shore of Lake Herrington. The station property itself consists of 664 acres with associated boilers, control devices, coal storage, and other supporting facilities on the property as shown in Figure 2-1. The facility is located in the Dix River Valley with modest terrain features throughout the area but no significant mountains. Adjacent land to the north, west, south, and east of the facility is generally rural or wooded.

2.2 UTM COORDINATE SYSTEM

The location of emission sources, structures, and receptors were represented in this modeling analysis in the Universal Transverse Mercator (UTM) coordinate system. The UTM grid divides the world into coordinates that are measured in north meters (measured from the equator) and east meters (measured from the central meridian of each specific zone with a width of 500 kilometers). The datum used herein was based on North American Datum 1983 (NAD 83). UTM coordinates for this analysis are located in UTM Zone 16. The general central location of the main stack at the E.ON Brown Station is approximately 701,178 meters East and 4,184,894 meters North in Zone 16. All subsequent calculations were conducted maintaining this NAD83 base coordinate system for all building coordinates and receptor locations.

FIGURE 2-1. E.W. BROWN STATION PLANT LAYOUT



3. RISK ASSESSMENT THRESHOLDS

Conceptually, a health risk assessment combines dose-response values for adverse health effects with the results of a dispersion model to estimate inhalation exposures of human populations to concentrations of potentially hazardous chemicals. Adverse health effects may be chronic (i.e., long-term exposures) or acute (i.e., short-term exposures) with acute impacts experienced over short timeframes ranging from minutes to a day and chronic impacts experienced on an annual basis. Chronic exposures are classified as either cancerous or non-cancerous.

Under 401 KAR 63:020, KDAQ does not set any specific ambient thresholds for a given pollutant nor does it establish a basis for determining an acceptable ambient concentration (except for those pollutants covered explicitly under 401 KAR 53). A facility can use any credible and technically justifiable risk assessment approach to demonstrate compliance. To this end, a review of risk assessment methodologies and risk thresholds for assessing H_2SO_4 impacts provided in both Federal and State air agency guidance documents was conducted. Of the acute and chronic risk thresholds established based on this review the most conservative were used as a benchmark against which the acute and chronic exposures due to H_2SO_4 emissions from the Brown Station were evaluated. Ambient H_2SO_4 impacts were evaluated using the acute H_2SO_4 risk threshold from the North Carolina Division for Air Quality Acceptable Ambient Level (AAL) under the state air toxics program, 100 $\mu g/m^3$ on a 1-hr average basis. The non-cancer chronic risk threshold used in the analysis, 1.0 $\mu g/m^3$ on an annual average basis, is the Benchmark Ambient Concentration used in the Louisville Metro Air Pollution Control District (LMAPCD) Strategic Toxic Air Reduction Program (STAR Program).

To provide an effective demonstration of possible acute or chronic risks using dispersion modeling results, a hazard quotient (HQ) was calculated for non-carcinogenic effects of H_2SO_4. The HQ is defined as the maximum predicted concentration ($\mu g/m^3$) of an individual compound divided by the applicable risk threshold. The risk thresholds are estimates of a continuous inhalation exposure to the human population that is likely to be without an appreciable risk of deleterious effects during a short-term (in this case, one hour exposure) event or a lifetime (annual) exposure. A resultant value of HQ less than 1 is considered acceptable; values greater than 1 are indicative of the potential for elevated risk of non-cancerous health impacts that should be evaluated further using more refined analyses.

4. SOURCE AND EMISSIONS CHARACTERIZATION

Only one source of H_2SO_4 emissions are of concern for the current modeling analysis, namely the new main stack at the Brown Station serving the three utility boilers–Units 1, 2 & 3. Emissions equal to **291.3 lb/hr** of H_2SO_4 were modeled through the single new stack (Stack ID 017).

With the exception of the stack coordinates and exhaust flowrate, stack parameters were set equal to values previously estimated by E.ON and represented on the DEP7007N form included in the March 2005 air permit application covering the installation of a new flue gas desulfurization system (along with the new stack). The flowrate value has been revised slightly based on more recent calculation estimates. The stack coordinates were revised to replace the less precise values that had previously been provided in the March 2005 application. Table 4-1 presents the stack information used in the modeling analysis.

TABLE 4-1. NEW MAIN STACK SOURCE PARAMETERS FOR E.ON BROWN STATION

Stack ID	**Stack Description**	**UTM, NAD83 Coordinates** **East** (m)	**North,** (m)	**Base Elev.** (m)	**Stack Height** (m)	**Stack Gas Temp.** (K)	**Stack Gas Exit Velocity**[a] (m/s)	**Stack Diameter** (m)
017	New Unit 1, 2 & 3 Main Stack	701,178	4,184,894	266.7	171	327	23.86	8.13

a. Based on an exhaust gas volume flowrate of 2,624,305 acfm for all three units exiting the stack

5. MODELING METHODOLOGY AND MODEL OPTIONS

5.1 MODEL SELECTION

The selection of a dispersion model to estimate short-term and long-term off-site exposure must take into account consideration of the physical geometry of the source, the local dispersion environment, and terrain characteristics. These factors formulate the basis for choosing one or more of the models recommended in the EPA modeling guidelines. In November 2005, EPA promulgated *Revision to Guideline on Air Quality Models* (*Guideline*), which contained recommendations on preferred air dispersion models to be used for assessing air quality impacts due to emissions from industrial facilities.[1] The revised *Guideline* specifies that **AMS/EPA R**egulatory **Mod**el (AERMOD), which includes the PRIME downwash algorithms, is the preferred model for refined modeling of an industrial facility. AERMOD is a refined, steady-state meteorology, multiple source, Gaussian dispersion model with improved treatment of turbulence in the planetary boundary layer and thus, its use was deemed appropriate for this modeling analysis.

The air dispersion modeling analysis for the Brown Station was conducted using the EPA-approved AERMOD model (Version 07026) to estimate maximum ground-level concentrations. AERMOD modeling was performed using all regulatory default options.

5.2 METEOROLOGICAL DATA

Refined dispersion models like AERMOD require a sequential hourly record of meteorology data representative of the region within which the source is located. In the absence of site-specific measurements, the EPA guidelines recommend the use of available meteorological data sets from the closest and most representative National Weather Service (NWS) stations.

For this modeling analysis, five years of surface meteorological data for 1988-1992 for the Lexington Bluegrass Airport (Station No. 93820) and upper air data from Wright Patterson Air Force Base in Dayton, Ohio (Station No. 13840) were used. Surface characteristics around the Lexington Bluegrass Airport were used in the AERSURFACE program to generate albedo, Bowen ratios, and surface roughness lengths which were consequently used to generate the meteorological data sets used in the modeling. Following recommendations in the *AERSURFACE User's Guide* and the current version of the *AERMOD Implementation Guide*, the determination of the surface roughness lengths was based on the inverse-distance weighted geometric mean applied in AERSURFACE with a default upwind distance of 1 kilometer relative to the measurement site for the study area radius.[2] [3] Since no consistent variations in land cover by direction were discernable in the 1-km area surrounding the

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[1] U.S. EPA, Office of Air Quality Planning and Standards, *Federal Register* Vol. 70 / No. 216, pp. 68,218-68,261, 40 CFR 51, Appendix W, *Revision to Guideline on Air Quality Models*, November 9, 2005.

[2] U.S. EPA, Office of Air Quality Planning and Standards. *AERSURFACE User's Guide*. EPA 454/B-08-001. Research Triangle Park, North Carolina. January 2008.

[3] U.S. EPA AERMOD Implementation Workgroup, *AERMOD Implementation Guide*, March 19, 2009

Lexington Bluegrass Airport anemometer, surface roughness lengths were evaluated in twelve (12) equal 30 degree sector starting at 0 degrees (i.e., due north) and rotating clockwise in 30 degree increments.

5.3 MODEL RECEPTOR GRID

In this air dispersion modeling analysis, ground-level concentrations were calculated throughout a Cartesian receptor grid and at receptors placed along the property line. The property line receptors were spaced 100 meters apart around the entire property boundary. The fine circular Cartesian grid beyond the fence line consists of 100-m spaced receptors extending out to five (5) kilometers in all directions. The receptors around the property were configured using public roads on the south and west and waterways on the east and north (refer to Figure 6-1 showing the modeled receptors). A single base elevation was used in the model data files for the boiler stack and buildings, because the area of the plant site where these structures are located is graded. Elevations of terrain for all receptors were derived from appropriate Digital Elevation Model (DEM) maps at 7.5' scale for the area.

5.4 BUILDING WAKE EFFECTS

The *Guideline on Air Quality Models* requires the evaluation of the potential for physical structures to affect the dispersion of emissions from stack sources. The exhaust from stacks that are located within specified distances of buildings and whose physical heights are below specified levels may be subject to "aerodynamic building downwash" under certain meteorological conditions. This determination is made by comparing actual stack heights to the Good Engineering Practice (GEP) stack height. An emission point is assumed to be subject to the effects of downwash if the release height is less than the minimum GEP stack height, which is defined by the following formula:

$$H_{GEP} = H + 1.5L$$

Where,

H_{GEP} = minimum GEP stack height,
H = structure height, and
L = lesser dimension of the structure (height or projected width).

This equation is limited to stacks located within 5L of a structure. Stacks located at a distance greater than 5L are not subject to the wake effects of the structure. EPA has promulgated stack height regulations that restrict the use of stack heights in excess of the maximum GEP height in air dispersion modeling analyses. The maximum GEP stack height for any source is the greater of 65 meters or H_{GEP}.[4] That portion of a stack in excess of the maximum GEP height is generally not creditable when modeling to determine source impacts. This essentially prevents the use of excessively tall stacks to reduce ground-level pollutant concentrations.

---

[4] 40 CFR §51.100(ii).

Major buildings were configured dimensionally and included in the modeling to consider downwash. Figures 5-1 through 5-4 show photos of the plant along with figures depicting the representations of these structures in the dispersion model. The direction-specific building dimensions used as input to AERMOD model were calculated using the *BREEZE®-AIR* software, developed by Trinity Consultants. This software incorporates the algorithms of the EPA-sanctioned Building Profile Input Program (BPIP), which has been adapted to incorporate the PRIME downwash algorithms and released by the EPA as "BPIPPRM" (version 04274). BPIPPRM was designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, the Building Downwash Guidance document, and other related documents, while incorporating the PRIME enhancements to improve prediction of ambient impacts in building cavities and wake regions.[5]

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[5] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations) (Revised)*, Research Triangle Park, North Carolina, EPA 450/4-80-023R, June 1985.

FIGURE 5-1. PHOTO WITH VIEW OF E.ON BROWN STATION LOOKING EAST SOUTHEAST

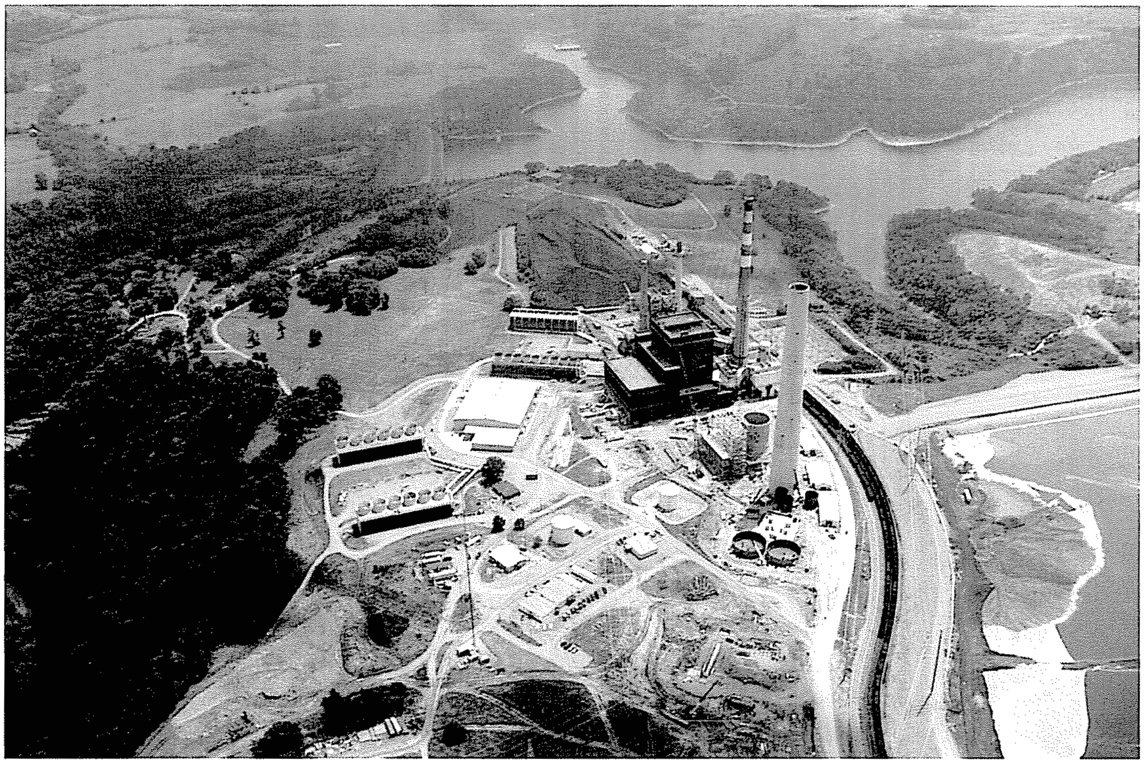


FIGURE 5-2. DEPICTION OF BUILDINGS IN *BREEZE* AERMOD LOOKING EAST SOUTHEAST

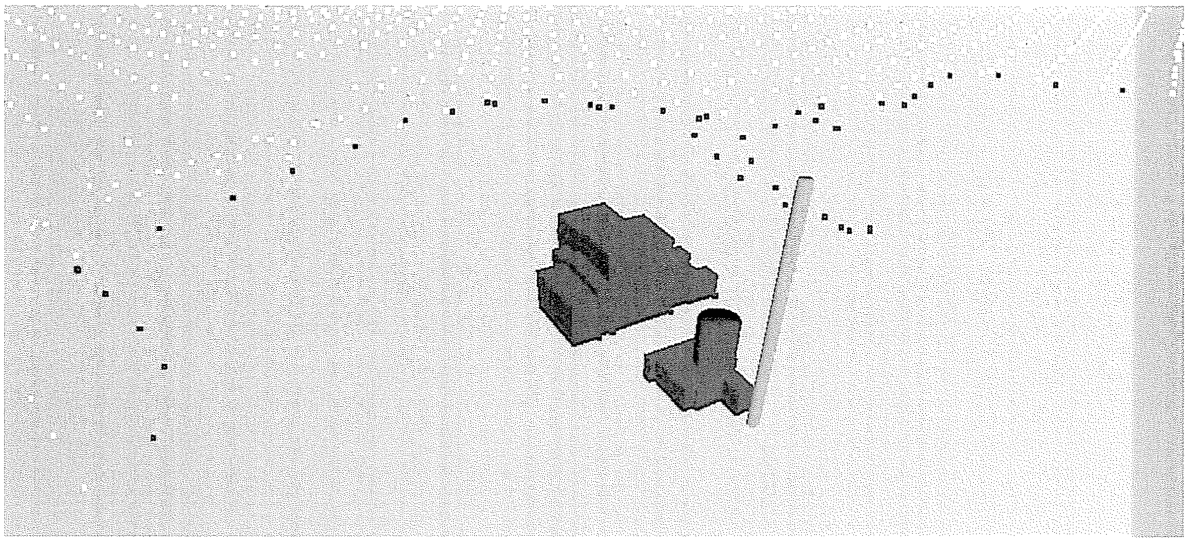


FIGURE 5-3. PHOTO WITH VIEW OF E.ON BROWN STATION LOOKING NORTH

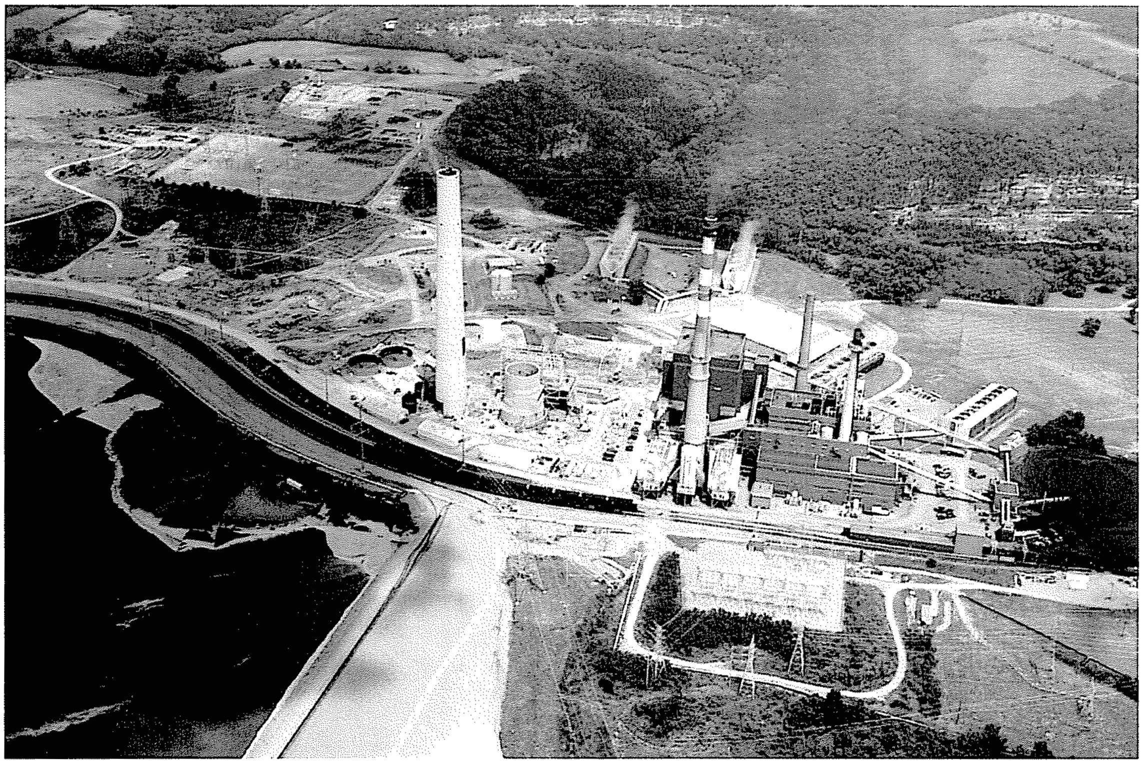
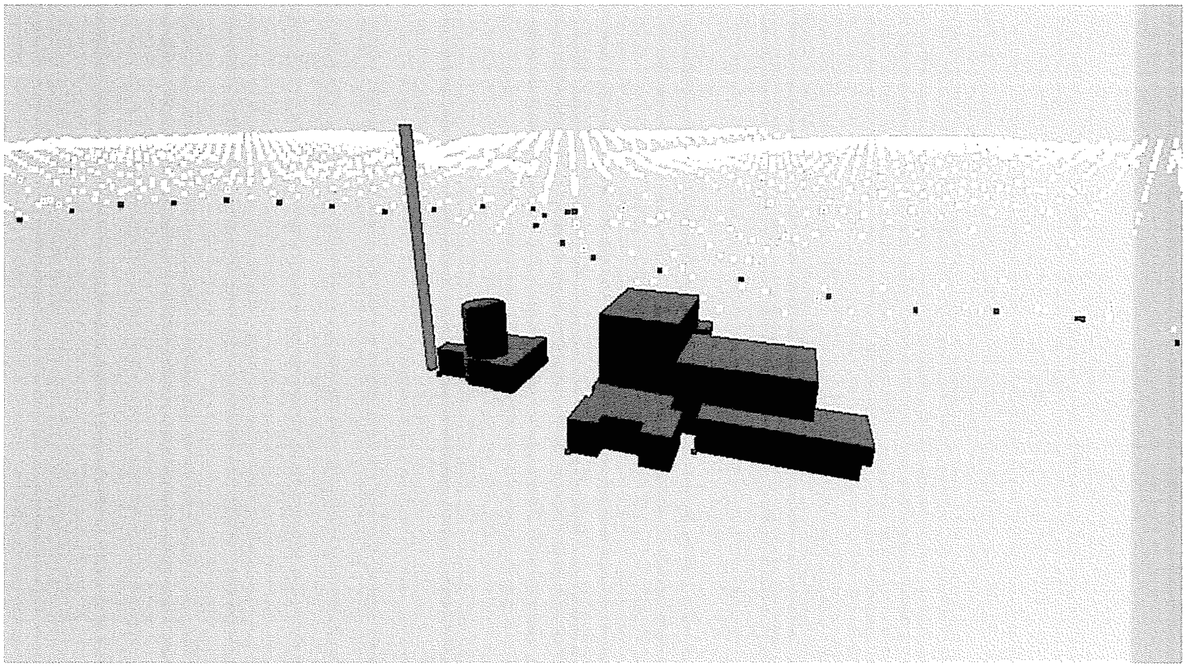


FIGURE 5-4. DEPICTION OF BUILDINGS IN *BREEZE* AERMOD LOOKING NORTH



5.5 MODEL OPTIONS

The AERMOD model was run for each of the five one-year periods specified in Section 5.2. To evaluate both short-term and long-term impacts, both one hour averages and annual averages were calculated to compare against the applicable risk thresholds. Source data used in the modeling analyses were provided in Table 4-1. AERMOD was run in EPA's regulatory default mode, which includes the following model switches:

- Elevated terrain algorithms requiring input of terrain height data
- Calms and missing meteorological data processing routines
- Maximum annual average concentrations
- Maximum 1-hour concentrations

6. H_2SO_4 RISK ASSESSMENT

6.1 EXPOSURE ASSESSMENT

The modeling analysis conducted used the conservatively estimated potential emission rates of H_2SO_4 from the new boiler stack, as described in Section 4, to evaluate potential off-site inhalation risks associated with H_2SO_4 emissions. The H_2SO_4 risk thresholds used represent an estimate of a continuous inhalation exposure to the human population that is likely to be without an appreciable risk of deleterious effects during a lifetime. Although risk assessments are typically conducted at potential locations were people congregate (i.e., residences, churches, recreation areas, etc.), this analysis conservatively relies on the maximum offsite H_2SO_4 impacts. The maximum offsite 1-hour average and annual average H_2SO_4 impacts at any receptor in the area surrounding the Brown Station were determined by the AERMOD model and are shown in Table 6-1. The maximum 1-hr impact occurs just beyond the property boundary southeast of the boiler stack and the maximum annual average impact occurs to the northeast of the plant site across Dix River and southeast of Bowman's Bend.

6.2 DETERMINATION OF HAZARD QUOTIENT

To evaluate whether the predicted H_2SO_4 impacts are considered acceptable (i.e., do not cause or contribute to adverse risk), the ratio of the maximum offsite impacts to the acute and chronic risk thresholds were each computed to yield a hazard quotient (HQ). As shown in Table 6-1 and in Figures 6-1 and 6-2, the maximum offsite 1-hour and annual average H_2SO_4 concentrations predicted in the air dispersion modeling analysis are equal to or less than 20 percent of the corresponding risk thresholds (i.e., the HQs are equal to or less than 0.20) which demonstrates that potential H_2SO_4 emissions from the new boiler stack after the modification will not pose an adverse health risk at any offsite location.

Electronic copies of the AERMOD input and output data files and meteorological data files for the modeling analyses completed can be provided upon request via email or ftp exchange.

TABLE 6-1. MAXIMUM MODELED OFF-SITE H_2SO_4 CONCENTRATIONS AND HAZARD QUOTIENTS

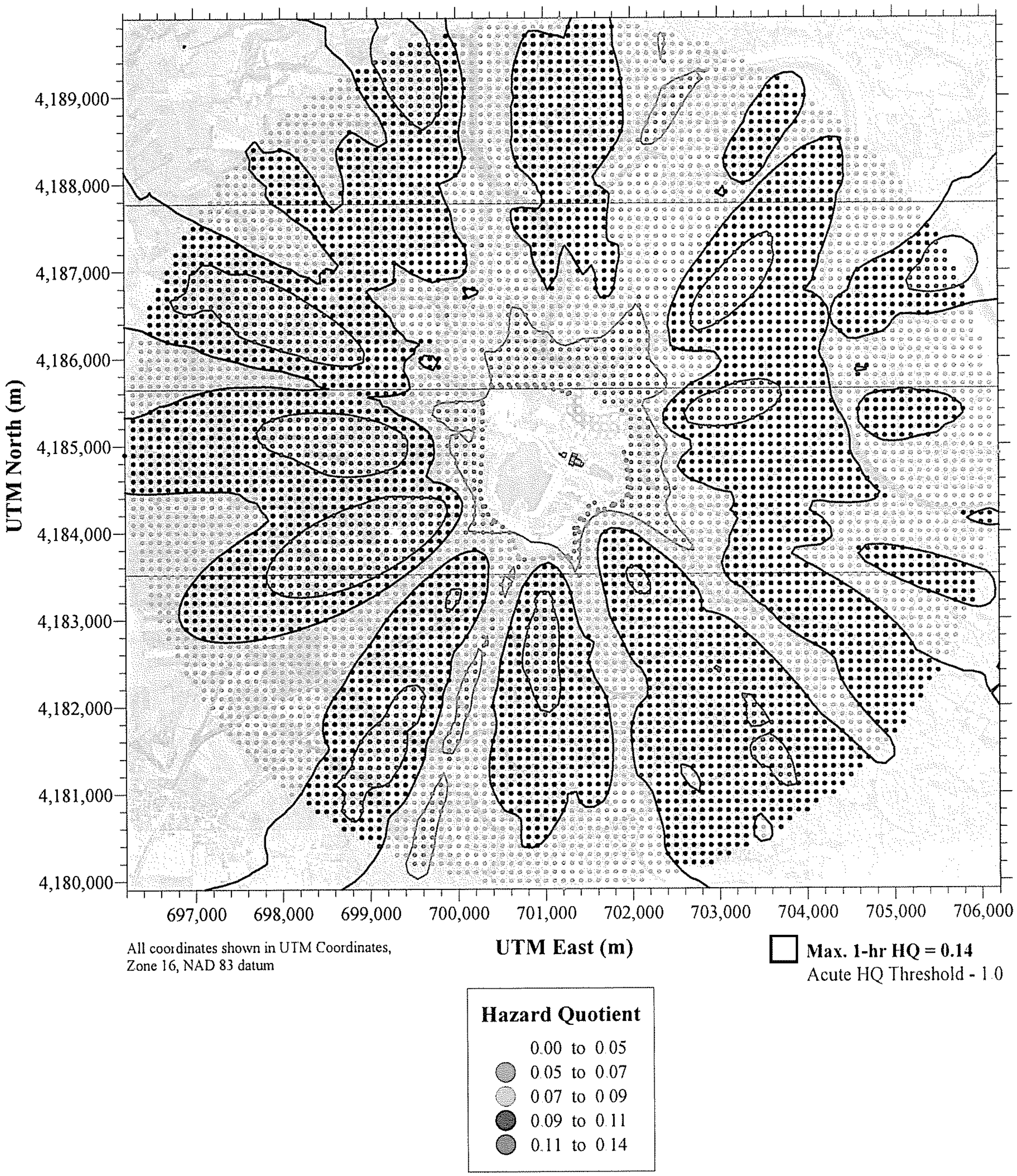
Averaging Period	Year	Risk Thresholds[2] ($\mu g/m^3$)	Maximum 1st High Impact ($\mu g/m^3$)	Maximum Hazard Quotient ($\mu g/m^3$)	UTM East[3] (m)	UTM North[3] (m)
1-hour[1]	1988-LEX	100	11.92	0.12	701,000	4,182,700
	1989-LEX	100	12.09	0.12	705,600	4,187,100
	1990-LEX	100	12.31	0.12	698,300	4,186,300
	1991-LEX	100	10.80	0.11	704,100	4,185,200
	1992-LEX	100	13.59	0.14	699,300	4,184,000
	Max. of 5 Years	**100**	**13.59**	**0.14**	**699,300**	**4,184,000**
Annual[1]	1988-LEX	1.0	0.17	0.17	703,000	4,186,000
	1989-LEX	1.0	0.18	0.18	703,000	4,186,000
	1990-LEX	1.0	0.20	0.20	702,700	4,186,400
	1991-LEX	1.0	0.19	0.19	702,900	4,186,300
	1992-LEX	1.0	0.19	0.19	702,900	4,186,300
	Max. of 5 Years	**1.0**	**0.20**	**0.20**	**702,700**	**4,186,400**

[1] Evaluated 1st high impacts for each year modeled since risk thresholds are not to be exceeded.

[2] Acute (1-hr) H_2SO_4 risk threshold is based on the North Carolina Division for Air Quality Acceptable Ambient Level (AAL) under their State Air Toxics Program. Non-cancer chronic (annual) H_2SO_4 risk threshold is based on the Louisville Metro Air Pollution Control District (LMAPCD) Benchmark Ambient Concentration (BAC).

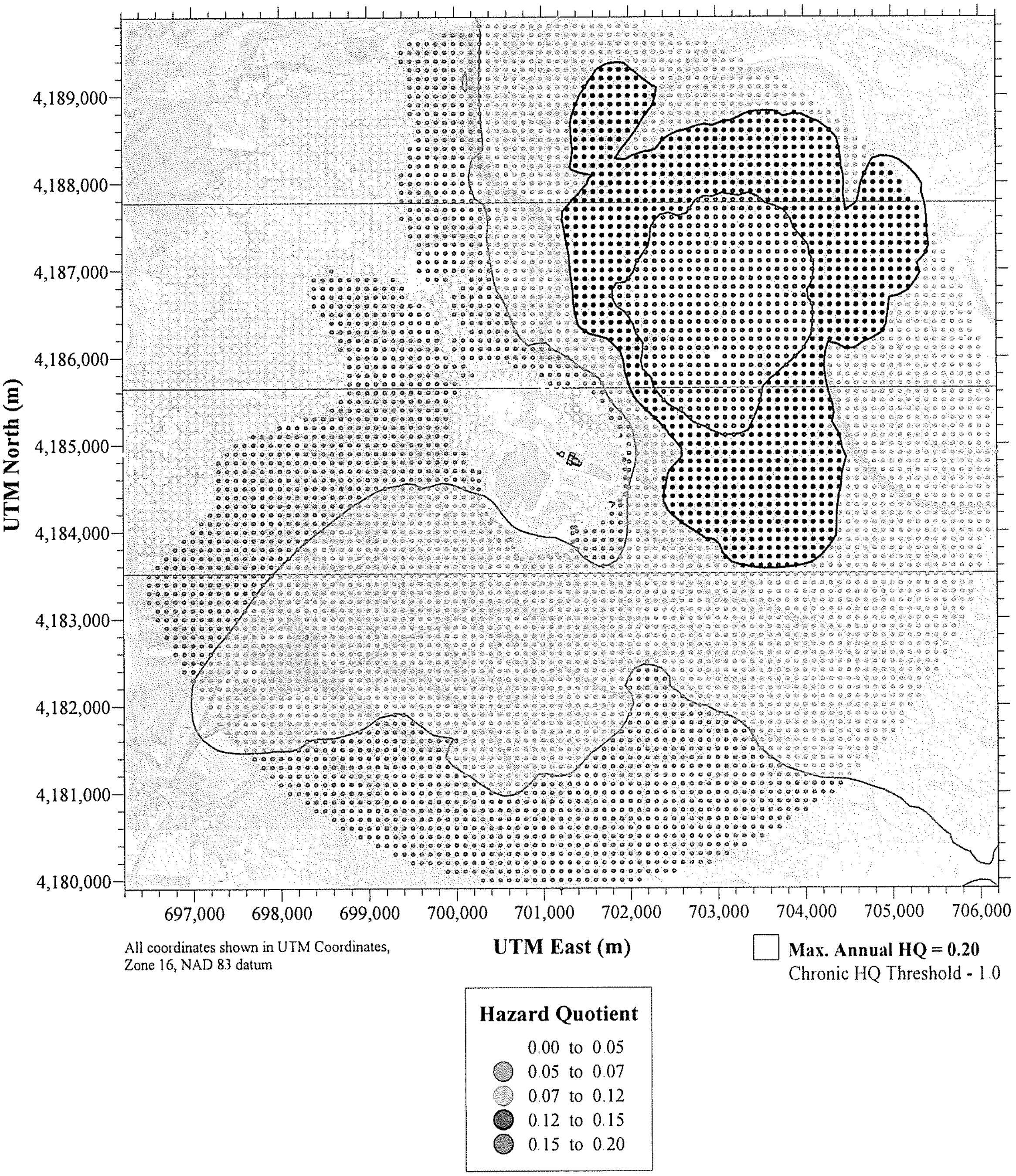
[3] UTM coordinates are in NAD83.

FIGURE 6-1. MAXIMUM 1ST HIGH 1-HR H_2SO_4 HAZARD QUOTIENT FROM AMONG FIVE METEOROLOGICAL YEARS MODELED



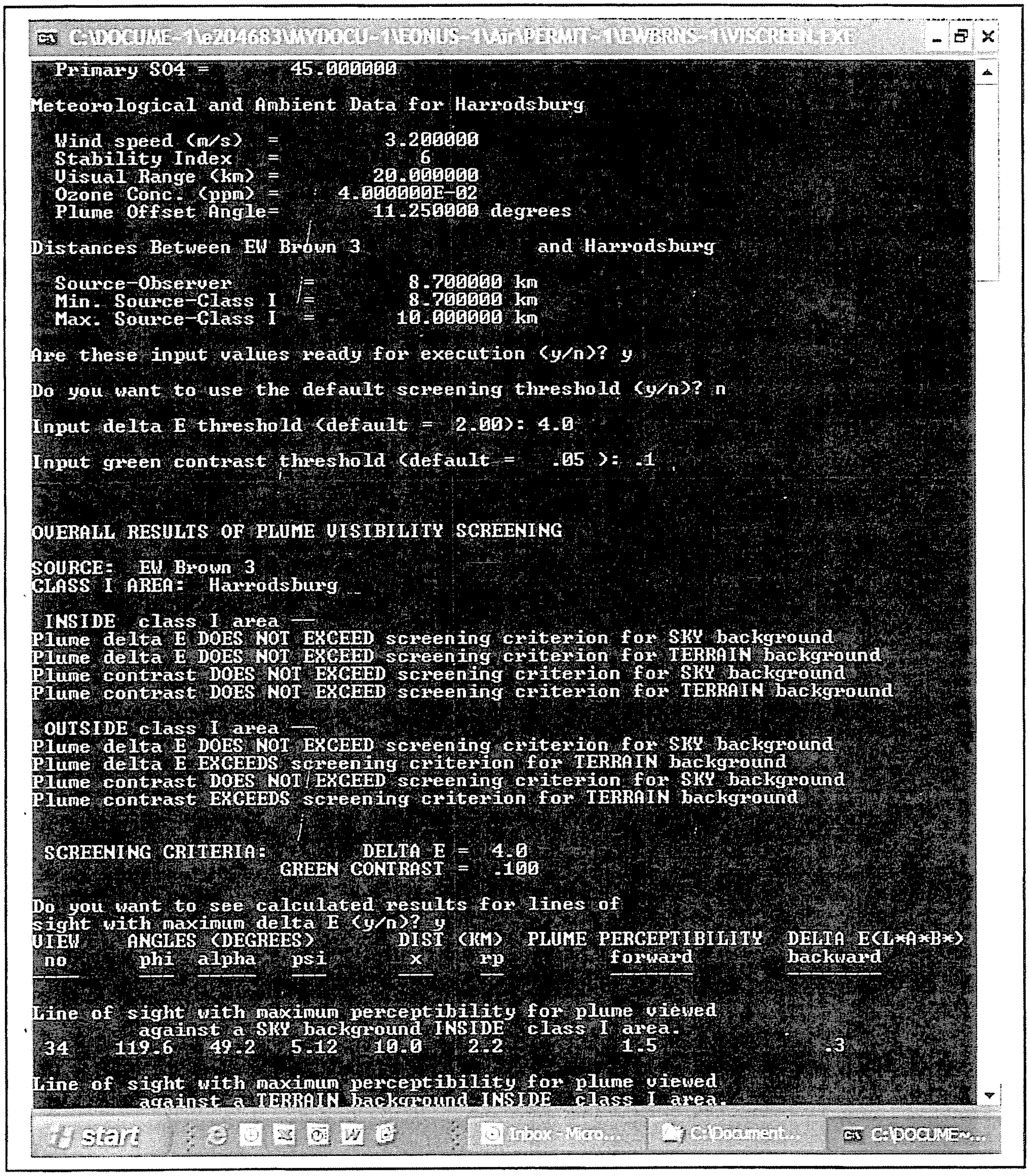
All coordinates shown in UTM Coordinates, Zone 16, NAD 83 datum

FIGURE 6-2. MAXIMUM ANNUAL H_2SO_4 HAZARD QUOTIENT FROM AMONG FIVE METEOROLOGICAL YEARS MODELED

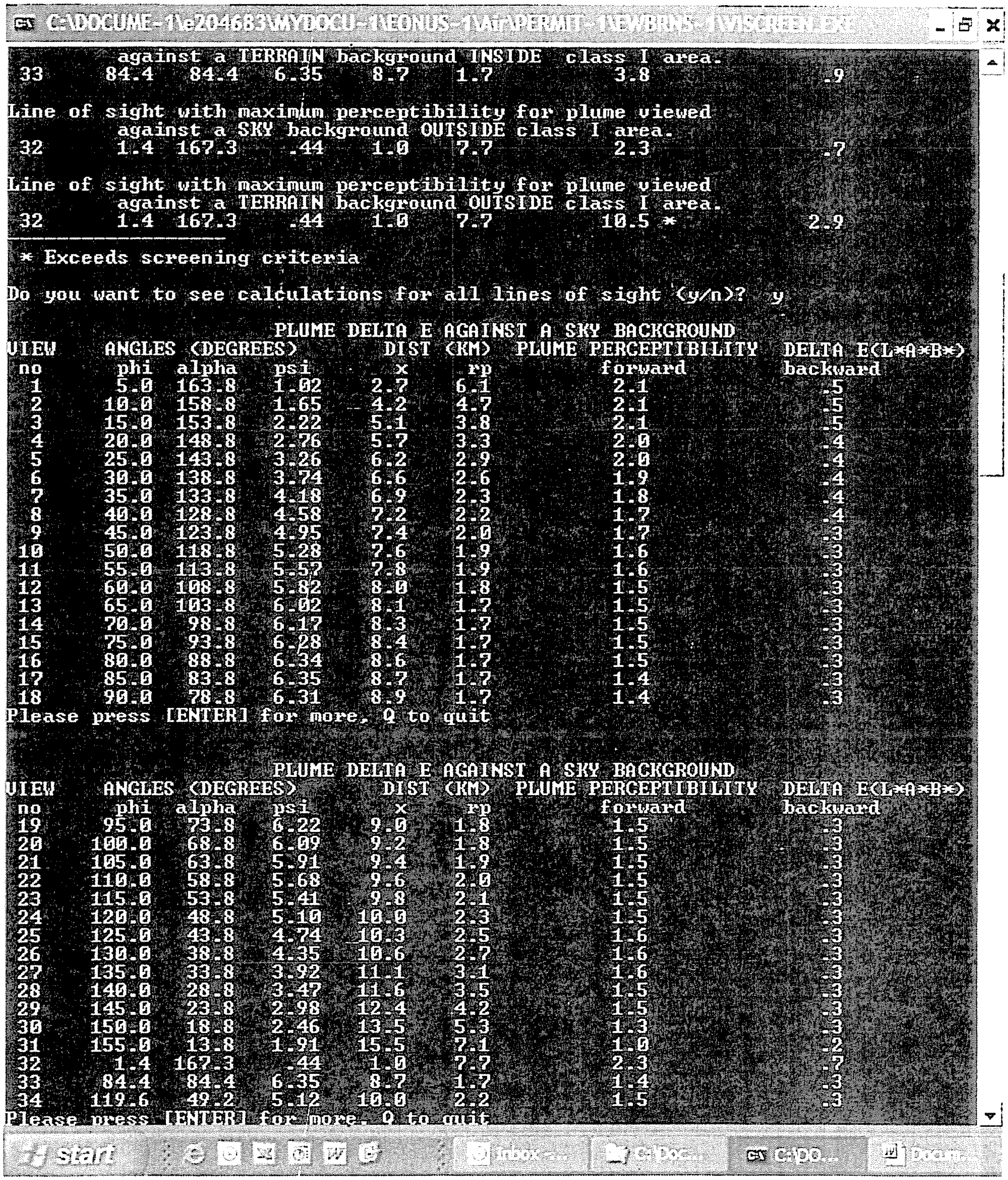


All coordinates shown in UTM Coordinates, Zone 16, NAD 83 datum

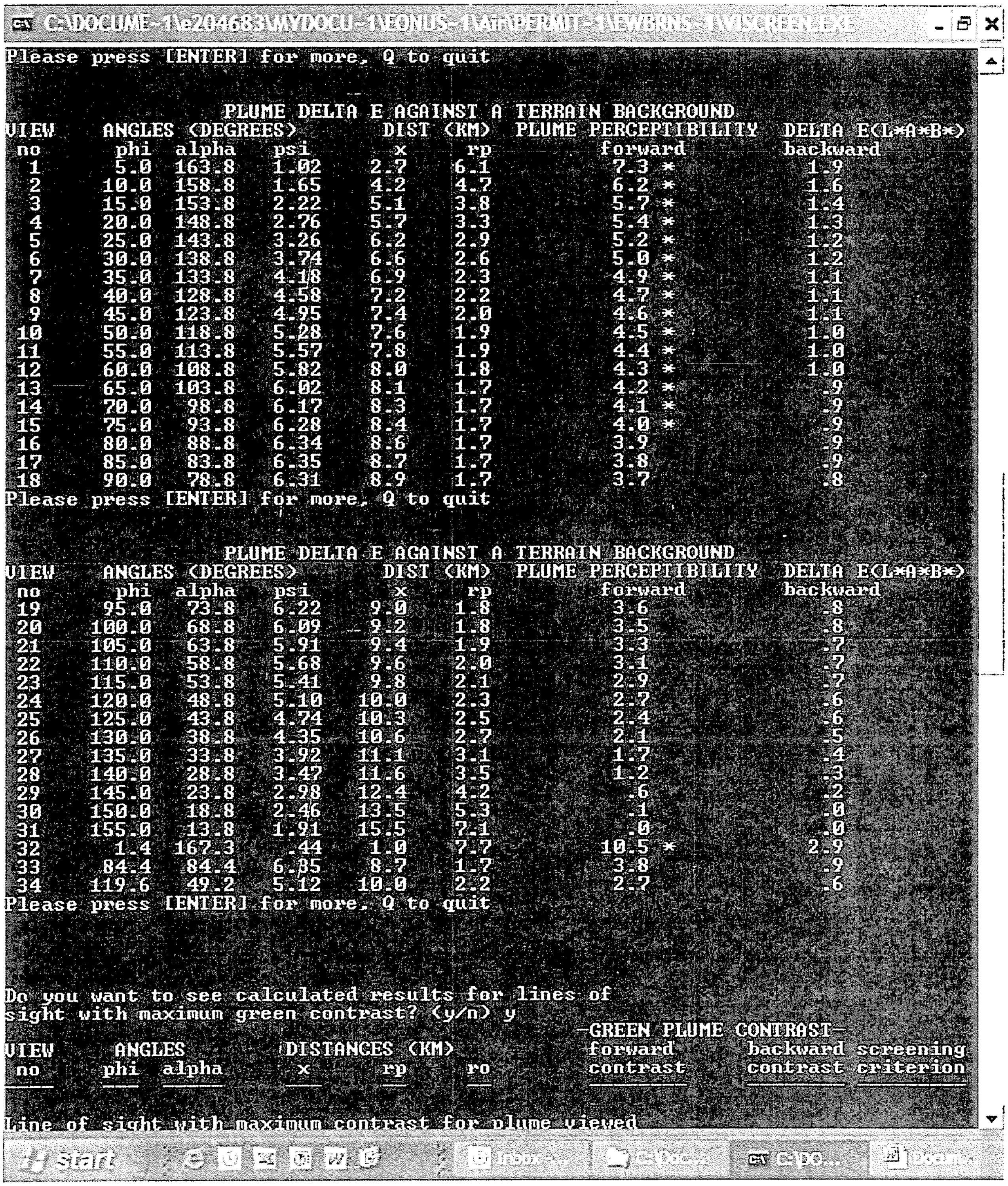
ATTACHMENT I



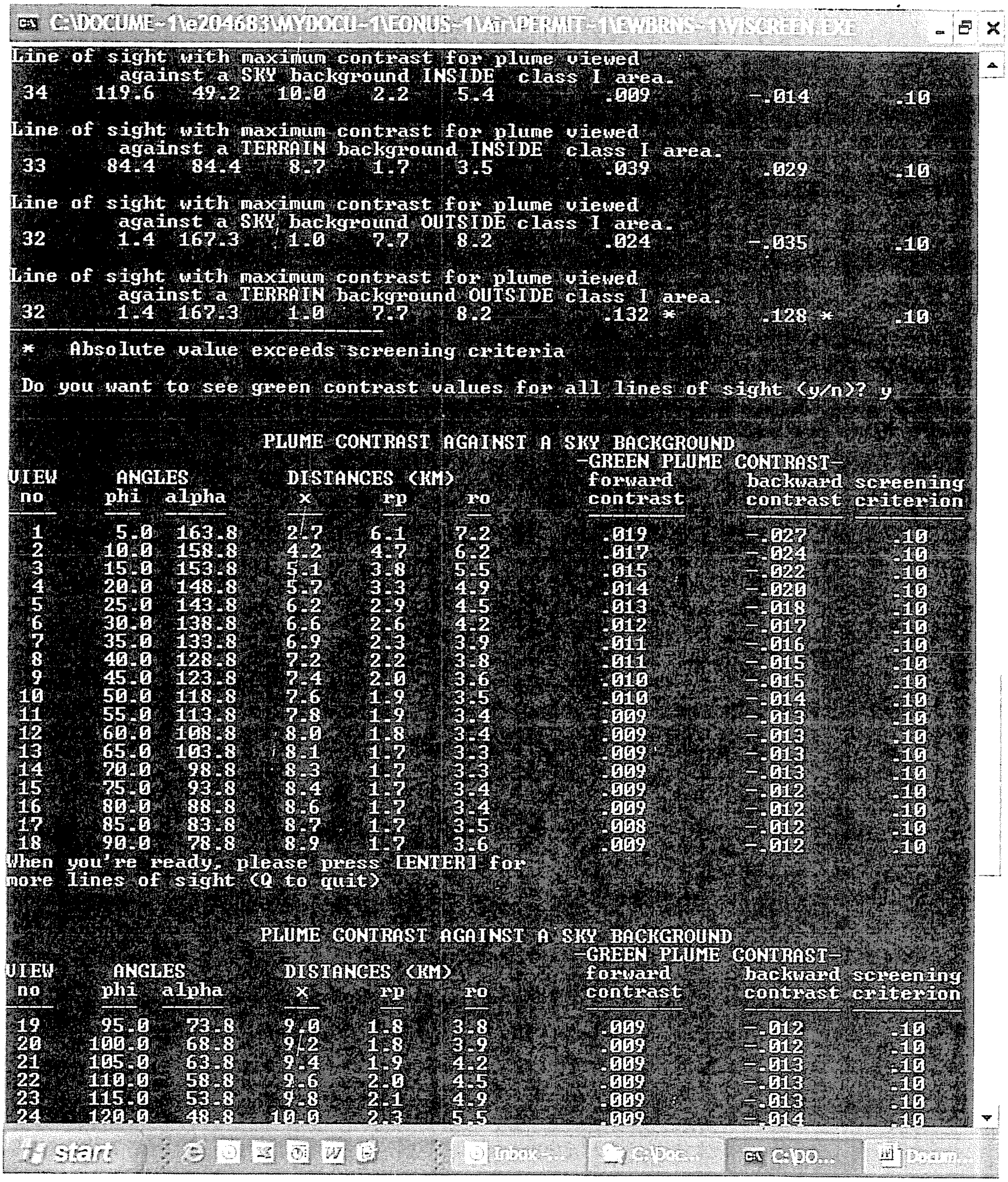
```
  Primary SO4 =         45.000000

Meteorological and Ambient Data for Harrodsburg

  Wind speed (m/s)  =          3.200000
  Stability Index   =             6
  Visual Range (km) =         20.000000
  Ozone Conc. (ppm) =      4.000000E-02
  Plume Offset Angle=         11.250000 degrees

Distances Between EW Brown 3                     and Harrodsburg

  Source-Observer        =          8.700000 km
  Min. Source-Class I    =          8.700000 km
  Max. Source-Class I    =         10.000000 km

Are these input values ready for execution (y/n)? y

Do you want to use the default screening threshold (y/n)? n

Input delta E threshold (default =  2.00): 4.0

Input green contrast threshold (default =   .05 ): .1



OVERALL RESULTS OF PLUME VISIBILITY SCREENING

SOURCE:  EW Brown 3
CLASS I AREA:   Harrodsburg _

 INSIDE  class I area --
Plume delta E DOES NOT EXCEED screening criterion for SKY background
Plume delta E DOES NOT EXCEED screening criterion for TERRAIN background
Plume contrast DOES NOT EXCEED screening criterion for SKY background
Plume contrast DOES NOT EXCEED screening criterion for TERRAIN background

 OUTSIDE class I area --
Plume delta E DOES NOT EXCEED screening criterion for SKY background
Plume delta E EXCEEDS screening criterion for TERRAIN background
Plume contrast DOES NOT EXCEED screening criterion for SKY background
Plume contrast EXCEEDS screening criterion for TERRAIN background


 SCREENING CRITERIA:          DELTA E =  4.0
                     GREEN CONTRAST =  .100

Do you want to see calculated results for lines of
sight with maximum delta E (y/n)? y
VIEW    ANGLES (DEGREES)        DIST (KM)  PLUME PERCEPTIBILITY  DELTA E(L*A*B*)
 no       phi  alpha   psi        x     rp          forward          backward
----      ---  -----   ---       ---    --          -------          --------

Line of sight with maximum perceptibility for plume viewed
         against a SKY background INSIDE  class I area.
 34    119.6   49.2   5.12   10.0    2.2             1.5               .3

Line of sight with maximum perceptibility for plume viewed
         against a TERRAIN background INSIDE  class I area.
```



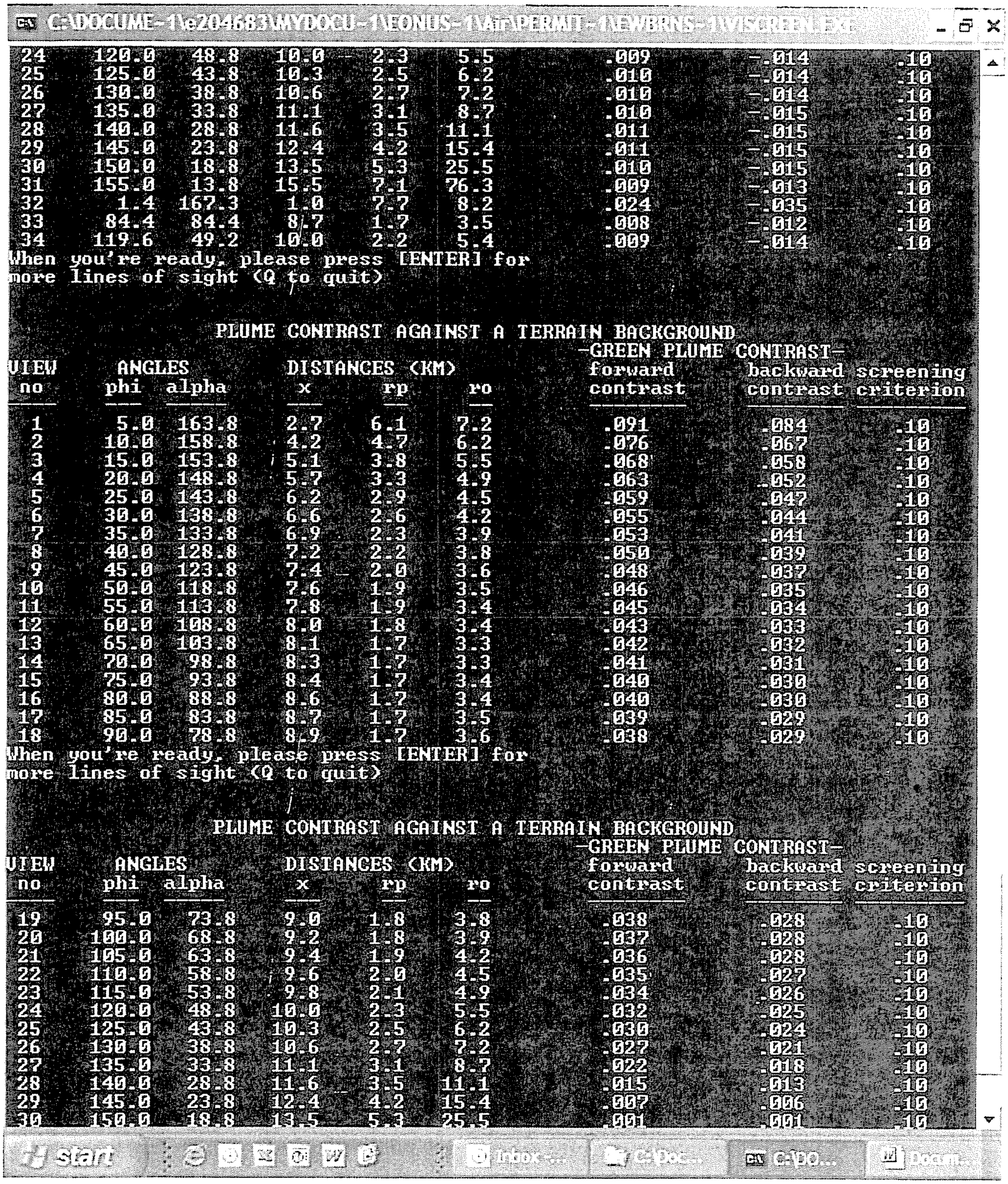
```
         against a TERRAIN background INSIDE  class I area.
 33     84.4   84.4   6.35    8.7    1.7          3.8              .9

Line of sight with maximum perceptibility for plume viewed
         against a SKY background OUTSIDE class I area.
 32      1.4  167.3    .44    1.0    7.7          2.3              .7

Line of sight with maximum perceptibility for plume viewed
         against a TERRAIN background OUTSIDE class I area.
 32      1.4  167.3    .44    1.0    7.7         10.5 *           2.9
──────────────────
 * Exceeds screening criteria

Do you want to see calculations for all lines of sight (y/n)?  y

                      PLUME DELTA E AGAINST A SKY BACKGROUND
VIEW    ANGLES (DEGREES)       DIST (KM)  PLUME PERCEPTIBILITY  DELTA E(L*A*B*)
 no      phi  alpha   psi       x     rp          forward        backward
  1      5.0  163.8   1.02    2.7    6.1          2.1              .5
  2     10.0  158.8   1.65    4.2    4.7          2.1              .5
  3     15.0  153.8   2.22    5.1    3.8          2.1              .5
  4     20.0  148.8   2.76    5.7    3.3          2.0              .4
  5     25.0  143.8   3.26    6.2    2.9          2.0              .4
  6     30.0  138.8   3.74    6.6    2.6          1.9              .4
  7     35.0  133.8   4.18    6.9    2.3          1.8              .4
  8     40.0  128.8   4.58    7.2    2.2          1.7              .4
  9     45.0  123.8   4.95    7.4    2.0          1.7              .3
 10     50.0  118.8   5.28    7.6    1.9          1.6              .3
 11     55.0  113.8   5.57    7.8    1.9          1.6              .3
 12     60.0  108.8   5.82    8.0    1.8          1.5              .3
 13     65.0  103.8   6.02    8.1    1.7          1.5              .3
 14     70.0   98.8   6.17    8.3    1.7          1.5              .3
 15     75.0   93.8   6.28    8.4    1.7          1.5              .3
 16     80.0   88.8   6.34    8.6    1.7          1.5              .3
 17     85.0   83.8   6.35    8.7    1.7          1.4              .3
 18     90.0   78.8   6.31    8.9    1.7          1.4              .3
Please press [ENTER] for more, Q to quit


                      PLUME DELTA E AGAINST A SKY BACKGROUND
VIEW    ANGLES (DEGREES)       DIST (KM)  PLUME PERCEPTIBILITY  DELTA E(L*A*B*)
 no      phi  alpha   psi       x     rp          forward        backward
 19     95.0   73.8   6.22    9.0    1.8          1.5              .3
 20    100.0   68.8   6.09    9.2    1.8          1.5              .3
 21    105.0   63.8   5.91    9.4    1.9          1.5              .3
 22    110.0   58.8   5.68    9.6    2.0          1.5              .3
 23    115.0   53.8   5.41    9.8    2.1          1.5              .3
 24    120.0   48.8   5.10   10.0    2.3          1.5              .3
 25    125.0   43.8   4.74   10.3    2.5          1.6              .3
 26    130.0   38.8   4.35   10.6    2.7          1.6              .3
 27    135.0   33.8   3.92   11.1    3.1          1.6              .3
 28    140.0   28.8   3.47   11.6    3.5          1.5              .3
 29    145.0   23.8   2.98   12.4    4.2          1.5              .3
 30    150.0   18.8   2.46   13.5    5.3          1.3              .3
 31    155.0   13.8   1.91   15.5    7.1          1.0              .2
 32      1.4  167.3    .44    1.0    7.7          2.3              .7
 33     84.4   84.4   6.35    8.7    1.7          1.4              .3
 34    119.6   49.2   5.12   10.0    2.2          1.5              .3
Please press [ENTER] for more, Q to quit
```



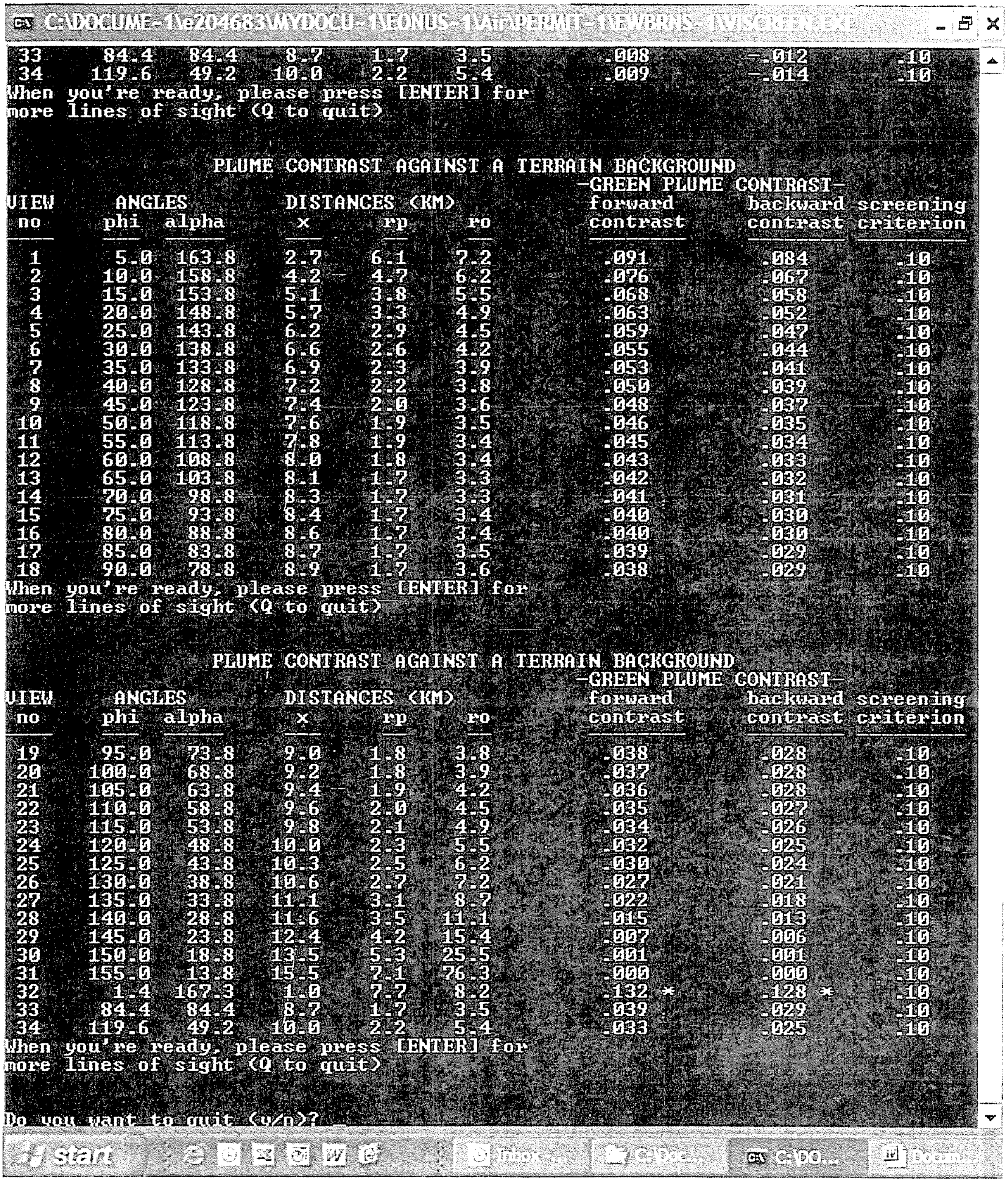
```
Please press [ENTER] for more, Q to quit


                PLUME DELTA E AGAINST A TERRAIN BACKGROUND
VIEW    ANGLES (DEGREES)       DIST (KM)  PLUME PERCEPTIBILITY  DELTA E(L*A*B*)
 no       phi  alpha   psi        x     rp          forward          backward
  1       5.0  163.8   1.02     2.7    6.1          7.3 *             1.9
  2      10.0  158.8   1.65     4.2    4.7          6.2 *             1.6
  3      15.0  153.8   2.22     5.1    3.8          5.7 *             1.4
  4      20.0  148.8   2.76     5.7    3.3          5.4 *             1.3
  5      25.0  143.8   3.26     6.2    2.9          5.2 *             1.2
  6      30.0  138.8   3.74     6.6    2.6          5.0 *             1.2
  7      35.0  133.8   4.18     6.9    2.3          4.9 *             1.1
  8      40.0  128.8   4.58     7.2    2.2          4.7 *             1.1
  9      45.0  123.8   4.95     7.4    2.0          4.6 *             1.1
 10      50.0  118.8   5.28     7.6    1.9          4.5 *             1.0
 11      55.0  113.8   5.57     7.8    1.9          4.4 *             1.0
 12      60.0  108.8   5.82     8.0    1.8          4.3 *             1.0
 13      65.0  103.8   6.02     8.1    1.7          4.2 *              .9
 14      70.0   98.8   6.17     8.3    1.7          4.1 *              .9
 15      75.0   93.8   6.28     8.4    1.7          4.0 *              .9
 16      80.0   88.8   6.34     8.6    1.7          3.9                .9
 17      85.0   83.8   6.35     8.7    1.7          3.8                .9
 18      90.0   78.8   6.31     8.9    1.7          3.7                .8
Please press [ENTER] for more, Q to quit


                PLUME DELTA E AGAINST A TERRAIN BACKGROUND
VIEW    ANGLES (DEGREES)       DIST (KM)  PLUME PERCEPTIBILITY  DELTA E(L*A*B*)
 no       phi  alpha   psi        x     rp          forward          backward
 19      95.0   73.8   6.22     9.0    1.8          3.6                .8
 20     100.0   68.8   6.09     9.2    1.8          3.5                .8
 21     105.0   63.8   5.91     9.4    1.9          3.3                .7
 22     110.0   58.8   5.68     9.6    2.0          3.1                .7
 23     115.0   53.8   5.41     9.8    2.1          2.9                .7
 24     120.0   48.8   5.10    10.0    2.3          2.7                .6
 25     125.0   43.8   4.74    10.3    2.5          2.4                .6
 26     130.0   38.8   4.35    10.6    2.7          2.1                .5
 27     135.0   33.8   3.92    11.1    3.1          1.7                .4
 28     140.0   28.8   3.47    11.6    3.5          1.2                .3
 29     145.0   23.8   2.98    12.4    4.2           .6                .2
 30     150.0   18.8   2.46    13.5    5.3           .1                .0
 31     155.0   13.8   1.91    15.5    7.1           .0                .0
 32       1.4  167.3    .44     1.0    7.7         10.5 *             2.9
 33      84.4   84.4   6.35     8.7    1.7          3.8                .9
 34     119.6   49.2   5.12    10.0    2.2          2.7                .6
Please press [ENTER] for more, Q to quit




Do you want to see calculated results for lines of
sight with maximum green contrast? (y/n) y
                                                  -GREEN PLUME CONTRAST-
VIEW     ANGLES         DISTANCES (KM)            forward     backward screening
 no      phi  alpha        x       rp      ro     contrast    contrast criterion
 ----    ---  ------     ----     ---     ---     --------    -------- ---------

Line of sight with maximum contrast for plume viewed
```



```
Line of sight with maximum contrast for plume viewed
        against a SKY background INSIDE  class I area.
 34    119.6   49.2   10.0    2.2    5.4          .009          -.014        .10

Line of sight with maximum contrast for plume viewed
        against a TERRAIN background INSIDE  class I area.
 33     84.4   84.4    8.7    1.7    3.5          .039           .029        .10

Line of sight with maximum contrast for plume viewed
        against a SKY background OUTSIDE class I area.
 32      1.4  167.3    1.0    7.7    8.2          .024          -.035        .10

Line of sight with maximum contrast for plume viewed
        against a TERRAIN background OUTSIDE class I area.
 32      1.4  167.3    1.0    7.7    8.2          .132 *         .128 *      .10
--------------------------------
 *   Absolute value exceeds screening criteria

 Do you want to see green contrast values for all lines of sight (y/n)? y


                    PLUME CONTRAST AGAINST A SKY BACKGROUND
                                                 -GREEN PLUME CONTRAST-
VIEW    ANGLES        DISTANCES (KM)              forward       backward screening
 no     phi  alpha      x       rp     ro         contrast      contrast criterion
 ----   ---  -----    ---      --     --          --------      -------- ---------
  1     5.0  163.8    2.7     6.1    7.2          .019          -.027        .10
  2    10.0  158.8    4.2     4.7    6.2          .017          -.024        .10
  3    15.0  153.8    5.1     3.8    5.5          .015          -.022        .10
  4    20.0  148.8    5.7     3.3    4.9          .014          -.020        .10
  5    25.0  143.8    6.2     2.9    4.5          .013          -.018        .10
  6    30.0  138.8    6.6     2.6    4.2          .012          -.017        .10
  7    35.0  133.8    6.9     2.3    3.9          .011          -.016        .10
  8    40.0  128.8    7.2     2.2    3.8          .011          -.015        .10
  9    45.0  123.8    7.4     2.0    3.6          .010          -.015        .10
 10    50.0  118.8    7.6     1.9    3.5          .010          -.014        .10
 11    55.0  113.8    7.8     1.9    3.4          .009          -.013        .10
 12    60.0  108.8    8.0     1.8    3.4          .009          -.013        .10
 13    65.0  103.8    8.1     1.7    3.3          .009          -.013        .10
 14    70.0   98.8    8.3     1.7    3.3          .009          -.013        .10
 15    75.0   93.8    8.4     1.7    3.4          .009          -.012        .10
 16    80.0   88.8    8.6     1.7    3.4          .009          -.012        .10
 17    85.0   83.8    8.7     1.7    3.5          .008          -.012        .10
 18    90.0   78.8    8.9     1.7    3.6          .009          -.012        .10
When you're ready, please press [ENTER] for
more lines of sight (Q to quit)


                    PLUME CONTRAST AGAINST A SKY BACKGROUND
                                                 -GREEN PLUME CONTRAST-
VIEW    ANGLES        DISTANCES (KM)              forward       backward screening
 no     phi  alpha      x       rp     ro         contrast      contrast criterion
 ----   ---  -----    ---      --     --          --------      -------- ---------
 19    95.0   73.8    9.0     1.8    3.8          .009          -.012        .10
 20   100.0   68.8    9.2     1.8    3.9          .009          -.012        .10
 21   105.0   63.8    9.4     1.9    4.2          .009          -.013        .10
 22   110.0   58.8    9.6     2.0    4.5          .009          -.013        .10
 23   115.0   53.8    9.8     2.1    4.9          .009          -.013        .10
 24   120.0   48.8   10.0     2.3    5.5          .009          -.014        .10
```



```
 24    120.0   48.8   10.0    2.3     5.5          .009          -.014      .10
 25    125.0   43.8   10.3    2.5     6.2          .010          -.014      .10
 26    130.0   38.8   10.6    2.7     7.2          .010          -.014      .10
 27    135.0   33.8   11.1    3.1     8.7          .010          -.015      .10
 28    140.0   28.8   11.6    3.5    11.1          .011          -.015      .10
 29    145.0   23.8   12.4    4.2    15.4          .011          -.015      .10
 30    150.0   18.8   13.5    5.3    25.5          .010          -.015      .10
 31    155.0   13.8   15.5    7.1    76.3          .009          -.013      .10
 32      1.4  167.3    1.0    7.7     8.2          .024          -.035      .10
 33     84.4   84.4    8.7    1.7     3.5          .008          -.012      .10
 34    119.6   49.2   10.0    2.2     5.4          .009          -.014      .10
When you're ready, please press [ENTER] for
more lines of sight (Q to quit)


                PLUME CONTRAST AGAINST A TERRAIN BACKGROUND
                                                   -GREEN PLUME CONTRAST-
VIEW     ANGLES         DISTANCES (KM)              forward       backward screening
 no      phi  alpha      x        rp      ro        contrast      contrast criterion
----     ---  -----     ---       --      --        --------      -------- ---------

  1       5.0  163.8    2.7     6.1     7.2          .091          .084       .10
  2      10.0  158.8    4.2     4.7     6.2          .076          .067       .10
  3      15.0  153.8    5.1     3.8     5.5          .068          .058       .10
  4      20.0  148.8    5.7     3.3     4.9          .063          .052       .10
  5      25.0  143.8    6.2     2.9     4.5          .059          .047       .10
  6      30.0  138.8    6.6     2.6     4.2          .055          .044       .10
  7      35.0  133.8    6.9     2.3     3.9          .053          .041       .10
  8      40.0  128.8    7.2     2.2     3.8          .050          .039       .10
  9      45.0  123.8    7.4     2.0     3.6          .048          .037       .10
 10      50.0  118.8    7.6     1.9     3.5          .046          .035       .10
 11      55.0  113.8    7.8     1.9     3.4          .045          .034       .10
 12      60.0  108.8    8.0     1.8     3.4          .043          .033       .10
 13      65.0  103.8    8.1     1.7     3.3          .042          .032       .10
 14      70.0   98.8    8.3     1.7     3.3          .041          .031       .10
 15      75.0   93.8    8.4     1.7     3.4          .040          .030       .10
 16      80.0   88.8    8.6     1.7     3.4          .040          .030       .10
 17      85.0   83.8    8.7     1.7     3.5          .039          .029       .10
 18      90.0   78.8    8.9     1.7     3.6          .038          .029       .10
When you're ready, please press [ENTER] for
more lines of sight (Q to quit)


                PLUME CONTRAST AGAINST A TERRAIN BACKGROUND
                                                   -GREEN PLUME CONTRAST-
VIEW     ANGLES         DISTANCES (KM)              forward       backward screening
 no      phi  alpha      x        rp      ro        contrast      contrast criterion
----     ---  -----     ---       --      --        --------      -------- ---------

 19      95.0   73.8    9.0     1.8     3.8          .038          .028       .10
 20     100.0   68.8    9.2     1.8     3.9          .037          .028       .10
 21     105.0   63.8    9.4     1.9     4.2          .036          .028       .10
 22     110.0   58.8    9.6     2.0     4.5          .035          .027       .10
 23     115.0   53.8    9.8     2.1     4.9          .034          .026       .10
 24     120.0   48.8   10.0     2.3     5.5          .032          .025       .10
 25     125.0   43.8   10.3     2.5     6.2          .030          .024       .10
 26     130.0   38.8   10.6     2.7     7.2          .027          .021       .10
 27     135.0   33.8   11.1     3.1     8.7          .022          .018       .10
 28     140.0   28.8   11.6     3.5    11.1          .015          .013       .10
 29     145.0   23.8   12.4     4.2    15.4          .007          .006       .10
 30     150.0   18.8   13.5     5.3    25.5          .001          .001       .10
```



```
 33     84.4   84.4    8.7    1.7    3.5         .008        -.012       .10
 34    119.6   49.2   10.0    2.2    5.4         .009        -.014       .10
When you're ready, please press [ENTER] for
more lines of sight (Q to quit)


                 PLUME CONTRAST AGAINST A TERRAIN BACKGROUND
                                               -GREEN PLUME CONTRAST-
VIEW     ANGLES        DISTANCES (KM)          forward      backward screening
 no     phi  alpha      x     rp      ro        contrast     contrast criterion
----    ---  -----     ---    --      --        --------     -------- ---------
  1      5.0  163.8    2.7    6.1    7.2         .091         .084       .10
  2     10.0  158.8    4.2    4.7    6.2         .076         .067       .10
  3     15.0  153.8    5.1    3.8    5.5         .068         .058       .10
  4     20.0  148.8    5.7    3.3    4.9         .063         .052       .10
  5     25.0  143.8    6.2    2.9    4.5         .059         .047       .10
  6     30.0  138.8    6.6    2.6    4.2         .055         .044       .10
  7     35.0  133.8    6.9    2.3    3.9         .053         .041       .10
  8     40.0  128.8    7.2    2.2    3.8         .050         .039       .10
  9     45.0  123.8    7.4    2.0    3.6         .048         .037       .10
 10     50.0  118.8    7.6    1.9    3.5         .046         .035       .10
 11     55.0  113.8    7.8    1.9    3.4         .045         .034       .10
 12     60.0  108.8    8.0    1.8    3.4         .043         .033       .10
 13     65.0  103.8    8.1    1.7    3.3         .042         .032       .10
 14     70.0   98.8    8.3    1.7    3.3         .041         .031       .10
 15     75.0   93.8    8.4    1.7    3.4         .040         .030       .10
 16     80.0   88.8    8.6    1.7    3.4         .040         .030       .10
 17     85.0   83.8    8.7    1.7    3.5         .039         .029       .10
 18     90.0   78.8    8.9    1.7    3.6         .038         .029       .10
When you're ready, please press [ENTER] for
more lines of sight (Q to quit)


                 PLUME CONTRAST AGAINST A TERRAIN BACKGROUND
                                               -GREEN PLUME CONTRAST-
VIEW     ANGLES        DISTANCES (KM)          forward      backward screening
 no     phi  alpha      x     rp      ro        contrast     contrast criterion
----    ---  -----     ---    --      --        --------     -------- ---------
 19     95.0   73.8    9.0    1.8    3.8         .038         .028       .10
 20    100.0   68.8    9.2    1.8    3.9         .037         .028       .10
 21    105.0   63.8    9.4    1.9    4.2         .036         .028       .10
 22    110.0   58.8    9.6    2.0    4.5         .035         .027       .10
 23    115.0   53.8    9.8    2.1    4.9         .034         .026       .10
 24    120.0   48.8   10.0    2.3    5.5         .032         .025       .10
 25    125.0   43.8   10.3    2.5    6.2         .030         .024       .10
 26    130.0   38.8   10.6    2.7    7.2         .027         .021       .10
 27    135.0   33.8   11.1    3.1    8.7         .022         .018       .10
 28    140.0   28.8   11.6    3.5   11.1         .015         .013       .10
 29    145.0   23.8   12.4    4.2   15.4         .007         .006       .10
 30    150.0   18.8   13.5    5.3   25.5         .001         .001       .10
 31    155.0   13.8   15.5    7.1   76.3         .000         .000       .10
 32      1.4  167.3    1.0    7.7    8.2         .132 *       .128 *     .10
 33     84.4   84.4    8.7    1.7    3.5         .039         .029       .10
 34    119.6   49.2   10.0    2.2    5.4         .033         .025       .10
When you're ready, please press [ENTER] for
more lines of sight (Q to quit)


Do you want to quit (y/n)? _
```