Florida Department of

Memorandum Environmental Protection

To: Trina Vielhauer, Bureau of Air Regulation

From: Jeff Koerner, New Source Review Section

Date: August 27, 2010

Subject: Draft Permit No. 0170004-023-AC (PSD-FL-383C)
Crystal River Power Plant, Units 4 and 5
Revisions to Pollution Control Project, Alkali Injection System

Progress Energy Florida, Inc. operates the existing Crystal River Power Plant, which is located in the Crystal River Energy Complex in Citrus County, north of Crystal River and west of U.S. Highway 19. This permit revision primarily addresses: limited periods of authorized shutdown of the alkali injection system for maintenance and repair; and clarifies that the deadline for submitting an application to revise the Title V air operation permit is after completing the proposed work for both units. Since the changes could increase SAM emissions, the draft permit package requires a 30-day comment period for the written and public notice. The Department's full review of the project is provided in the Technical Evaluation and Preliminary Determination. I recommend your approval of the attached Draft Permit package.

Attachments

TLV/jfk

P.E. CERTIFICATION STATEMENT

PERMITTEE

Progress Energy Florida, Inc.
Crystal River Power Plant
299 First Avenue North, CN-77
St. Petersburg, Florida 33701

Project No. 0170004-023-AC
PSD-FL-383C
Crystal River Power Plant, Units 4 and 5
Revisions to Pollution Controls Project

PROJECT DESCRIPTION

Progress Energy Florida, Inc. operates the existing Crystal River Power Plant, which is located in the Crystal River Energy Complex in Citrus County, north of Crystal River and west of U.S. Highway 19. Permit No. PSD-FL-383 (as modified) authorized the following: new low-NO_X burners, new SCR systems, new FGD systems, new alkali injection systems, a new carbon burn out unit, upgraded ESP and new stack configurations. This permit revision modifies the current air construction permit to:

- Authorize limited periods of shutdown of the alkali injection system for maintenance and repair; and
- Clarify that the deadline for submitting an application to revise the Title V air operation permit is after completing the proposed work for both units.

The facility is an existing major stationary source and the original project was subject to PSD preconstruction review, including a BACT determination for SAM emissions. Since the proposed changes revise the original PSD permit and could increase SAM emissions, the draft permit package requires a 30-day comment period for the written and public notice. The Department's full review of the project is provided in the Technical Evaluation and Preliminary Determination.

I HEREBY CERTIFY *that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify any other aspects of the proposal (including, but not limited to, the electrical, civil, mechanical, structural, hydrological, geological, and meteorological features).*

Jeffery F. Koerner, P.E.
Registration Number 49441

8-22-08
(Date)

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

September 3, 2010

Mr. Larry Hatcher, Plant Manager
Crystal River Power Plant
Progress Energy Florida, Inc.
299 First Avenue North, CN77
St. Petersburg, FL 33701

Re: Project No. 0170004-023-AC (PSD-FL-383C)
Progress Energy Florida, Inc - Crystal River Power Plant
Revisions to Pollution Control Project, Units 4 and 5
Alkali Injection System for Sulfuric Acid Mist Control

Dear Mr. Hatcher:

You submitted an application requesting miscellaneous revisions to original Permit No. PSD-FL-383 for the ongoing air pollution control project being installed on Units 4 and 5. The existing Crystal River Power Plant is located in Citrus County, north of Crystal River and west of U.S. Highway 19. Enclosed are the following documents: the Technical Evaluation and Preliminary Determination; the Draft Permit and Appendices; the Written Notice of Intent to Issue Air Permit; and the Public Notice of Intent to Issue Air Permit. The Public Notice of Intent to Issue Air Permit is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project. If you have any questions, please contact the project engineer, Jeff Koerner, at 850/921-9536.

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

TLV/jfk

In the Matter of an
Application for Air Permit by:

Progress Energy Florida, Inc.
299 First Avenue, North, CN77
St. Petersburg, FL 33701

Authorized Representative:
Mr. Larry Hatcher, Plant Manager

Draft Permit No. 0170004-023-AC
PSD-FL-383C
Progress Energy Florida
Crystal River Power Plant, Units 4 and 5
Revisions to Pollution Control Project
Citrus County, Florida

Facility Location: Progress Energy Florida, Inc. operates the existing Crystal River Power Plant, which is located in Citrus County, north of Crystal River and west of U.S. Highway 19.

Project: The existing facility is a major stationary source and the original project was subject to preconstruction review pursuant to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality, including a determination of the Best Available Control Technology (BACT) for sulfuric acid mist emissions. In accordance with original Permit No. PSD-FL-383, Progress Energy Florida, Inc. is currently constructing the following air pollution control equipment for existing Units 4 and 5 at the Crystal River Power Plant: new low-NO_X burners and selective catalytic reduction systems to reduce nitrogen oxide (NO_X) emissions; new flue gas desulfurization systems to reduce sulfur dioxide emissions; a new alkali injection system to reduce sulfuric acid mist emissions; upgraded electrostatic precipitators to reduce particulate matter emissions; and new stack configurations. The proposed project will revise the original permit to: authorize limited periods of shutdown of the alkali injection system for maintenance and repair; and clarify that the deadline for submitting an application to revise the Title V air operation permit is after completing the proposed work on both units. Depending on the frequency of equipment malfunctions, sulfuric acid mist emissions could increase as a result of the project.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address or phone number listed above.

Notice of Intent to Issue Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Permit

(Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at above address or phone number. Pursuant to Rule 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 7 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit and requests for a public meeting for a period of 30 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 30-day period. In addition, if a public meeting is requested within the 30-day comment period and conducted by the Permitting Authority, any oral and written comments received during the public meeting will also be considered by the Permitting Authority. If timely received comments result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within 14 days of receipt of this Written Notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of the attached Public Notice or within 14 days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Written Notice of Intent to Issue Air Permit package (including the Written Notice of Intent to Issue Air Permit, the Public Notice of Intent to Issue Air Permit, the Technical Evaluation and Preliminary Determination and the Draft Permit with Appendices) was sent by electronic mail (or a link to these documents made available electronically on a publicly accessible server) with received receipt requested before the close of business on 9/3/10 to the persons listed below.

Mr. Larry Hatcher, Progress Energy, Inc. (larry.hatcher@pgnmail.com)
Mr. Dave Meyer, Progress Energy, Inc. (dave.meyer@pgnmail.com)
Mr. Scott Osbourn, Golder Associates (sosbourn@golder.com)
Mr. Mike Halpin, DEP Siting (mike.halpin@dep.state.fl.us)
Ms. Cindy Zhang-Torres, DEP SWD (cindy.zhang-torres@dep.state.fl.us)
Ms. Katy Forney, EPA Region 4 (forney.kathleen@epa.gov)
Ms. Heather Abrams, EPA Region 4 (abrams.heather@epamail.epa.gov)
Ms. Ana M. Oquendo, EPA Region 4 (oquendo.ana@epa.gov)
Mr. Dee Morse, NPS (dee_morse@nps.gov)
Ms. Vickie Gibson, DEP BAR Reading File (victoria.gibson@dep.state.fl.us)

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

(Clerk) 9/3/10 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Division of Air Resource Management, Bureau of Air Regulation

Draft Air Permit No. PSD-FL-383C / Project No. 0170004-023-AC
Progress Energy Florida, Inc., Crystal River Power Plant
Citrus County, Florida

Applicant: The applicant for this project is Progress Energy Florida, Inc. The applicant's authorized representative and mailing address is: Mr. Larry Hatcher, Plant Manager, Crystal River Power Plant, Progress Energy Florida, Inc., 299 First Avenue, North, CN77, St. Petersburg, FL 33701.

Facility Location: The existing Crystal River Power Plant is located north of Crystal River and west of U.S. Highway 19 in Citrus County, Florida.

Project: The existing facility is a major stationary source and the original project was subject to preconstruction review pursuant to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality, including a determination of the Best Available Control Technology (BACT) for SAM emissions. In accordance with original Permit No. PSD-FL-383, Progress Energy Florida, Inc. is currently constructing the following air pollution control equipment for existing Units 4 and 5 at the Crystal River Power Plant: new low-NO_X burners and selective catalytic reduction systems to reduce nitrogen oxide (NO_X) emissions; new flue gas desulfurization systems to reduce sulfur dioxide emissions; a new alkali injection system to reduce sulfuric acid mist emissions; upgraded electrostatic precipitators to reduce particulate matter emissions; and new stack configurations. The proposed project will revise the original permit to: authorize limited periods of shutdown of the alkali injection system for maintenance and repair; and clarify that the deadline for submitting an application to revise the Title V air operation permit is after completing the proposed work on both units. Depending on the frequency of equipment malfunctions, sulfuric acid mist emissions could increase as a result of the project.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210 and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Permitting Authority responsible for making a permit determination for this project is the Bureau of Air Regulation in the Department of Environmental Protection's Division of Air Resource Management. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at the physical address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application and information submitted by the applicant (exclusive of confidential records under Section 403.111, F.S.). Interested persons may contact the Permitting Authority's project engineer for additional information at the address and phone number listed above. In addition, electronic copies of these documents are available on the following web site: http://www.dep.state.fl.us/air/emission/apds/default.asp.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air construction permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit and requests for a public meeting for a period of 30 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 30-day period. In addition, if a public meeting is requested within the 30-day comment period and conducted by the Permitting Authority, any oral and written comments received during the public meeting will also be considered by the Permitting Authority. If timely received comments result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241). Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within 14 days of publication of this Public Notice or receipt of a written notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address and telephone number of the petitioner; the name address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial rights will be affected by the agency determination; (c) A statement of when and how the petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available for this proceeding.

TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

Progress Energy Florida
299 First Avenue North, CN77
St. Petersburg, FL 33701

PROJECT

Air Permit No. PSD-FL-383C
Project No. 0170004-023-AC

Crystal River Power Plant
ARMS Facility ID No. 0170004
Revisions to FGD/SCR Projects for Units 4 and 5

COUNTY

Citrus County, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
New Source Review Section
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

August 27, 2010

1. GENERAL PROJECT INFORMATION

Air Pollution Regulations

Projects with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of Environmental Protection (Department) to establish regulations regarding air quality as part of the Florida Administrative Code (F.A.C.), which includes the following chapters: 62-4 (Permits); 62-204 (Air Pollution Control – General Provisions); 62-210 (Stationary Sources – General Requirements); 62-212 (Stationary Sources – Preconstruction Review); 62-213 (Operation Permits for Major Sources of Air Pollution); 62-296 (Stationary Sources - Emission Standards); and 62-297 (Stationary Sources – Emissions Monitoring). Specifically, air construction permits are required pursuant to Rules 62-4, 62-210 and 62-212, F.A.C.

In addition, the U. S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 specifies New Source Performance Standards (NSPS) for numerous industrial activities. Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP) based on specific pollutants. Part 63 specifies NESHAP based on the Maximum Achievable Control Technology (MACT) for numerous industrial categories. The Department adopts these federal regulations on a quarterly basis in Rule 62-204.800, F.A.C.

Glossary of Common Terms

Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of this permit.

Facility Description and Location

The existing Crystal River Power Plant (SIC No. 4911) is located in the Crystal River Energy Complex in Citrus County, north of Crystal River and west of U.S. Highway 19. The existing plant consists of the following units: four coal-fired steam generating units with electrostatic precipitators; two natural draft cooling towers; two sets of mechanical draft cooling towers; coal and ash material handling facilities; and relocatable diesel fired generators. The Crystal River Energy Complex includes a nuclear unit and associated facilities permitted under the same Title V air operation permit. The UTM coordinates are Zone17, 334.3 km East, and 3204.5 km North. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to state and federal Ambient Air Quality Standards (AAQS).

Facility Regulatory Categories

- The facility is a major source of hazardous air pollutants (HAP).
- The facility operates units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.
- The existing facility is subject to Power Plant Site Certification No. PA 77-09.

Project Description

Only the following existing emissions units will be affected by the proposed project.

ID No.	Description
003	Unit 5 Fossil Fuel Steam Generator
004	Unit 4 Fossil Fuel Steam Generator

In May of 2007, the Department issued Permit No. PSD-FL-383, which included authorization of the following air pollution control equipment for existing Units 4 and 5: new low-NO_X burners (LNB) and new selective catalytic reduction (SCR) systems to reduce nitrogen oxides (NO_X); new wet flue gas desulfurization (FGD) systems to reduce sulfur dioxide (SO_2) and other acid gas emissions; new alkali injection systems to reduce sulfuric acid mist (SAM) emissions; upgraded electrostatic precipitators (ESP) to reduce particulate matter emissions; new stack configurations; and a new carbon burn out unit. The purpose of the original project was to implement the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

In February of 2009, revised Permit No. PSD-FL-383A (Project No. 0170004-019-AC) required operation of the wet FGD and SCR systems in response to the Environmental Protection Agency's revised 8-hour ozone standard.

In May of 2009, the Department issued revised Permit No. PSD-FL-383B (Project No. 0170004-022-AC) to: include a temporary alternate compliance demonstration for carbon monoxide emissions for Unit 5 until the continuous emissions monitoring system is installed during the outage to tie in the new wet FGD system and stack; correct as-built equipment descriptions for the gypsum storage and handling systems; acknowledge that the limestone crushing operations will be subject to the federal provisions in NSPS Subpart OOO of 40 CFR 60; and clarify the timeframes for compliance monitoring following completion of construction, startup and shakedown of the air pollution control systems.

As part of the original application to modify the permit, the applicant requested authorized periods of shutdown for the alkali injection system to conduct maintenance while one or more of the units continued to operate. However, the applicant later requested that this item be separated into a subsequent project (Project No. 0170004-023-AC) to provide additional time to gather information in support of the request related to alkali injection equipment, which is also known as the acid mist mitigation (AMM) system.

Processing Schedule

12/30/08: Received application for original Project No. 0170004-022-AC.

01/28/09: Department requested additional information.

03/02/09: Department received part of the additional information requested.

05/11/09 Project No. 0170004-022-AC issued to: address temporary alternate compliance demonstration for carbon monoxide emissions for Unit 5 until the continuous emissions monitoring system is installed during the outage to tie in the new wet FGD system and stack; correct as-built equipment descriptions for the gypsum storage and handling systems; acknowledge that the limestone crushing operations will be subject to the federal provisions in NSPS Subpart OOO of 40 CFR 60; and clarify the timeframes for compliance monitoring following completion of construction, startup and shakedown of the air pollution control systems.

As requested by the applicant, separate Project 0170004-023-AC was created to provide additional time for applicant to gather additional information to support the request for authorized periods of shutdown of the AMM system to conduct maintenance; incomplete. With regard to operation of the AMM system, the applicant provided additional information on 09/29/09, 10/28/09, 01/25/10, 02/24/10, 04/01/10 and 06/17/10 (complete).

2. DEPARTMENT REVIEW

Section 2, Condition 6: Clarifying the Submittal Date of the Application to Revise Title V Permit

Request: This condition states, "This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a

Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require." The applicant requests clarification that an application to revise the Title V air operation permit is required once the authorized work on both units is complete.

Response: Although the project is being completed in stages for each unit, the authorized work on Unit 4 will finish within a few months of Unit 5. In addition, the AMM system is a common system for both units and shakedown will not be complete until both units return to operation. Therefore, the Department agrees that the application to revise the Title V air operation permit shall be submitted once the work is complete on both units. The Department will clarify the condition with the following revision, "The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after completing the work on both units and commencing operation."

Section 3A, Condition 2b, SCR Bypass Issue

Request: In an e-mail dated August 12, 2010, the applicant indicated that the SCR bypass system does not allow access to a unit while it is operating. Therefore, the applicant requests that the following sentence be deleted from Condition 2b, "During catalyst maintenance and repair, the bypass would also allow access to the SCR reactor without requiring the complete shutdown of a unit."

Response: This sentence was deleted as requested. In addition, the following phrase was deleted from the first sentence of the second paragraph under the Facility and Project Description in Section 1, "Due to the Environmental Protection Agency's revised 8-hour ozone standard, the permittee shall install and continuously operate new low-NO_X burners, new selective catalytic reduction systems, new flue gas desulfurization systems, and new stack configurations for existing Units 4 and 5 as authorized by this permit~~, except for designed periods of SCR bypass as specified in condition 2.b~~.

Section 3A, Conditions 8 and 10, Authorized Shutdown of the AMM System for Preventive Maintenance

Request – Part 1: The applicant requested authorization to shut down the AMM system for preventive maintenance for up to 10 days per unit per calendar year. This is necessary to ensure reliable operation because the AMM system shares common critical components for both Units 4 and 5. The equipment vendor recommends the following scheduled annual preventative maintenance to minimize SAM emissions from malfunctions causing unplanned downtime and repairs:

- Testing and maintenance of the isolation and pressure relief valves for the urea auxiliary steam supply line;
- Maintenance of the isolation valves on the condensate return line to the plant;
- Inspection and cleaning of spray nozzles for the urea steam saturator and for the urea condensate recovery tank; and
- Inspection of the AMM urea solution day tank and the AMM hydrolyzer blow-down tank.

The scheduled preventive maintenance will take approximately 192 hours (8 days). The applicant requests authorization for an additional 48 hours to respond to unavoidable maintenance issues such as leaks in steam lines, valves and piping. Preventive maintenance on the AMM system will be scheduled for one of the alternating planned outages for either Unit 4 or Unit 5, which occur at 18-month intervals. Therefore, preventive maintenance on the AMM system will be scheduled for a period when one of the units is off line, which will take place about every nine months. The applicant states that it is necessary for one of these units to remain on line to maintain electrical system reliability.

SAM emissions are generated by two primary mechanisms: directly during combustion as a function of the fuel sulfur; and conversion of SO_2 across the SCR catalyst to sulfur trioxide (SO_3) and eventually to sulfuric acid mist (H_2SO_4). In addition, SAM emissions are reduced at three separate points: the air heaters, the ESP and the FGD system. Injecting ammonia with the AMM system can improve SAM removal at the ESP to more than 90%. During normal operation with the maximum permitted high-sulfur coal (3.13% by weight), the AMM system is required to control SAM emissions and comply with a BACT standard of 0.009 lb/MMBtu and 64.8 lb/hour. For the scheduled preventive maintenance periods, the applicant agrees to fire coal from the stockpile for Units 1 and 2, which currently has a sulfur content of less than 1.0% by weight. For comparison, the following table summarizes SAM emissions for ten days of operation.

Table A. SAM Emissions for One Unit Operating 240 Hours

Operation	Units	Permit Case[a] AMM On	Tested[b] AMM On	Tested[b] AMM Off	Estimated[c] AMM Off	
Maximum Coal Sulfur Content	% by weight	3.13%	1.68%	1.68%	3.13%	1.0%
Coal Heating Value	Btu/lb	11,375	12,181	12,181	11,375	12,181
Uncontrolled SO_2 Emissions	lb/MMBtu	5.5	2.76	2.76	5.5	1.64
Heat Input Rate	MMBtu/hour	7200	7200	7200	7200	7200
SAM Emission Rate	lb/MMBtu	0.009	0.001	0.017	0.032	0.01
SAM Emission Rate	lb/hour	64.8	7.2	122.4	230.4	72.0
Potential SAM Emissions (10 days, 240 hours)	Tons	7.8	0.9	14.7	27.6	8.6

Notes:

a. Potential SAM emissions based on BACT standard of 0.009 lb/MMBtu.

b. Actual SAM emissions based on stack test conducted in March and April of 2010.

c. Estimated SAM emissions for 3.13% sulfur coal with AMM system off were scaled up from actual tested SAM emissions for 1.68% coal with AMM system off. A similar estimate was made for SAM emissions for 1% sulfur coal.

So, during normal operation and complying with the SAM emissions standard while firing coal with the maximum permitted sulfur content (3.13% by weight), potential SAM emissions from *both* units will be 15.6 tons for the 10-day period. Actual tested SAM emissions for 1.68% sulfur coal with the AMM system on indicate SAM emissions of 1.8 tons from both units for the 10-day period. If one unit was shut down and the AMM system was off line for preventive maintenance, estimated SAM emissions would be 27.6 tons from the one operating unit when firing 3.13% sulfur coal. If the plant switches to a coal with no more than 1.0% sulfur for the 10-day preventive maintenance period, estimated SAM emissions would be only 8.6 tons, which is less than the case for both units operating on 3.13% sulfur coal and complying with the BACT standard. Also, note that the estimated SAM emissions while firing 1.0% sulfur coal with the AMM system off are only 0.01 lb/MMBtu, which is almost in compliance with the BACT standard.

Response – Part 1: Since the preventive maintenance will be conducted on the low-sulfur coal with only one unit in operation, SAM emissions will be minimized and actually be less than full permitted operation for both units. The Department approves this request.

Request – Part 2: In addition to preventive maintenance, the applicant requests an additional period of up to 480 hours per year to operate the units without the AMM system on line in order to repair malfunctions to the AMM system. Since malfunctions are unavoidable, the applicant requests authorization to continue to operate both base-loaded units to maintain electrical system reliability.

Response – Part 2: The Department requested information related to the cost of providing redundant components so that each unit could operate with an independent AMM system. Based on a contractor estimate from the Environmental Partners Crystal River (EPCR), the applicant provided the following "order of magnitude" cost estimate:

Table B. Estimated "Order of Magnitude" Costs for Redundant AMM System Components

Description	Cost
Engineering, Office	$446,443
Engineering, Field Support	$19,290
Engineering Startup	$50,480
Procurement/Subcontract	$1,508,950
Construction, Labor	$550,807
Construction, Materials	$282,947
Contractor Markup	$388,813
Contingency (25%)	$811,932
Total	$4,059,662

Although the Department does not support this "order of magnitude" cost estimate, it is noted that this estimated cost would be in addition to the $8 million for the currently installed system. As previously described, the applicant agrees to minimize SAM emissions caused by maintenance and repair of the AMM system by scheduling and conducting annual preventive maintenance during which one unit will be down and the other unit will fire low-sulfur coal stockpiled from Units 1 and 2. This practice will reduce the number of "unavoidable" malfunctions of the AMM system that will require separate repair resulting in excess emissions.

Despite a thorough preventive maintenance plan, unexpected malfunctions and excess emissions will occur and the plant must promptly repair the AMM system. Depending on the particular component, many repairs may be possible in just a few hours, while other repairs will take several days. To provide operational flexibility and maintain plant safety while minimizing SAM emissions, the draft permit includes the following conditions in Subsection 3A of the permit.

- The draft permit requires additional SAM testing to determine actual emissions while firing low-sulfur coal stockpiled from Units 1 and 2, which is typically less than 1% sulfur by weight. The purpose of the tests is to determine whether enough overall SAM control is provided by other components (i.e., the air heaters, the ESP without the AMM system and the wet FGD system) to demonstrate that the units remain in compliance with the BACT standard while firing the low-sulfur coal.
- The draft permit requires scheduled annual preventive maintenance to minimize malfunctions of the AMM system that result in excess SAM emissions. To minimize excess SAM emissions, only one unit may operate during this period and that unit shall only fire low-sulfur coal stockpiled from Units 1 and 2. Operation in this manner is limited to no more than 240 hours per year; however, if additional tests on the low-sulfur coal show compliance with the BACT standard for SAM emissions, such hours of operation will not count towards the operational restriction on hours.
- The draft permit authorizes up to 480 hours with one or both units in operation while the AMM system is malfunctioning or off line for repair. Malfunctions must be immediately investigated to determine the corrective action required. For malfunctions that will require an extended period of time to repair, the permittee shall begin preparations to fire low-sulfur coal stockpiled from Units 1 and 2. For lengthy repairs, the plant shall begin firing the low-sulfur coal no later than 72 hours after the malfunction. If additional tests on the low-sulfur coal show compliance with the BACT standard for SAM emissions, such hours of operation will not count towards the operational restriction on hours.
- The draft permit also includes a method to determine the maximum coal sulfur content predicted to show compliance with the BACT standard for SAM emissions based on prorating the actual tested sulfur content with a factor derived from the BACT standard and the actual tested SAM emissions.

Depending on the frequency of unavoidable malfunctions, this change could result in SAM emissions increases. The Department notes that potential SAM emissions are 46.7 tons when operating both units at the permitted BACT limit for a total of 720 hours. Based on the proposed changes (240 hours of preventive maintenance plus 480 hours of repair), potential SAM emissions are 72.6 tons when operating the units within the operational restrictions and firing high-sulfur coal (3.13% by weight). However, this worst-case is highly unlikely given that the permit requires annual preventive maintenance for the AMM system. To provide a more realistic estimate, the following assumptions were made:

- 240 hours of operation with one unit firing low-sulfur coal (1% by weight) without control for preventive maintenance;
- Each unit having one malfunction repaired within 72 hours while firing high-sulfur coal (3.13 % by weight) without control; and
- Each unit having one malfunction resulting in 72 hours while firing high-sulfur coal (3.13 % by weight) without control followed by a switch to low-sulfur coal (1% by weight) for another 72 hours without control and completing the repair.

This scenario provides the preventive maintenance period and four malfunction incidents. The maximum SAM emissions are estimated to be 47 tons, which is just above the potential emissions estimated at the BACT standard for full operation of both units.

Section 3A, Condition 16e: Clarification of the SAM Performance Test Report

Request: The applicant requests the following minor change to this condition, "Within 45 days following the submittal of the ~~emissions~~ performance test report and no later than 90 days following the last test run conducted, the permittee shall submit an operating protocol and report summarizing the following ..."

Response: The Department agrees to this clarification.

3. PSD APPLICABILITY REVIEW

The project is located in Citrus County, which is in an area that is currently in attainment with the state and federal AAQS or otherwise designated as unclassifiable. The facility is an existing major stationary source and the original project to install the SCR, FGD and AMM systems was subject to PSD preconstruction review and included a BACT determination for SAM emissions. The proposed project affects the stringency of the original BACT determination for SAM emissions and results in a potential increase in SAM emissions. Therefore, the request results in a substantial revision of the PSD permit and the Department will require a 30-day comment period for the public notice.

4. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the Draft Permit. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit changes. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

DRAFT PERMIT

PERMITTEE

Progress Energy Florida, Inc.
Crystal River Power Plant
299 First Avenue North, CN-77
St. Petersburg, Florida 33701

Authorized Representative:
Mr. Larry Hatcher, Plant Manager

Air Permit No. PSD-FL-383C Project No. 0170004-023-AC Facility ID No. 0170004 Crystal River Power Plant, Units 4 and 5 Revised Air Pollution Controls Project Permit Expires: November 1, 2011

PROJECT

This is the final air construction permit revision, which modifies original Permit No. PSD-FL-383 that authorized new air pollution controls on Units 4 and 5. The proposed work is being conducted at the existing Crystal River Power Plant, which is a power plant categorized under Standard Industrial Classification No. 4911. The existing plant is located north of Crystal River and west of U.S. Highway 19 in Citrus County, Florida.

This final permit is organized into the following sections: Section 1 (General Information); Section 2 (Administrative Requirements); Section 3 (Emissions Unit Specific Conditions); Section 4 (Appendices). Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of Section 4 of this permit. As noted in the Final Determination provided with this final permit, only minor changes and clarifications were made to the draft permit.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of: Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C. and the preconstruction review requirements for major stationary sources in Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

Upon issuance of this final permit, any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida

(DRAFT)

Joseph Kahn, Director (Date)
Division of Air Resource Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final Air Permit package (including the Final Determination and Final Permit with Appendices) was sent by electronic mail, or a link to these documents made available electronically on a publicly accessible server, with received receipt requested before the close of business on __________(DRAFT)__________ to the persons listed below.

Mr. Larry Hatcher, Progress Energy, Inc. (larry.hatcher@pgnmail.com)
Mr. Dave Meyer, Progress Energy, Inc. (dave.meyer@pgnmail.com)
Mr. Scott Osbourn, Golder Associates (sosbourn@golder.com)
Mr. Mike Halpin, DEP Siting (mike.halpin@dep.state.fl.us)
Ms. Cindy Zhang-Torres, DEP SWD (cindy.zhang-torres@dep.state.fl.us)
Ms. Katy Forney, EPA Region 4 (forney.kathleen@epa.gov)
Ms. Heather Abrams, EPA Region 4 (abrams.heather@epamail.epa.gov)
Ms. Ana M. Oquendo, EPA Region 4 (oquendo.ana@epa.gov)
Mr. Dee Morse, NPS (dee_morse@nps.gov)
Ms. Vickie Gibson, DEP BAR Reading File (victoria.gibson@dep.state.fl.us)

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

(DRAFT)

______________________________ (Clerk) ______________ (Date)

FACILITY AND PROJECT DESCRIPTION

The existing Crystal River Power Plant consists of the following: four coal-fired fossil fuel steam generating units with electrostatic precipitators; two natural draft cooling towers; two sets of mechanical draft cooling towers (one set of "helper" cooling towers and a second set of "modular" cooling towers); coal and ash material handling facilities; and relocatable diesel fired generators. The Crystal River Energy Complex includes the nuclear unit and associated facilities permitted under the same Title V air operation permit.

Due to the Environmental Protection Agency's revised 8-hour ozone standard, the permittee shall install and continuously operate new low-NO_X burners, new selective catalytic reduction systems, new flue gas desulfurization systems, and new stack configurations for existing Units 4 and 5 as authorized by this permit~~, except for designed periods of SCR bypass as specified in condition 2.b~~. The installation and use of these control devices require a demonstration of continuous compliance with new standards for NO_X and SO_2.

In conjunction with the proposed new control equipment, the permit also authorizes the following: a new carbon burn-out (CBO^{TM}) system to reburn fly ash, a new blend of bituminous/sub-bituminous coal, a trial burn to evaluate coals blends with up to 30% petroleum coke, and a trial burn to evaluate a new fuel additive intended to reduce slagging and improve emissions performance. This permit also establishes the maximum heat input rates for Units 4 and 5. The combination of new fuel blends and control equipment will result in PSD-significant emissions increases of carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and volatile organic compounds (VOC). Therefore, the permittee is also required to perform the following work and install the following additional equipment as the Best Available Control Technologies (BACT) for these pollutants: the new low-NOx burners (CO, PM/PM_{10}, and VOC); modifications to the existing electrostatic precipitators (PM/PM_{10} and SAM); and new alkali injection systems (SAM).

This permit affects the following emissions units:

EU No.	New/Existing	Emission Unit Description
001	Existing	Unit 1 Fossil Fuel Steam Generator
002	Existing	Unit 2 Fossil Fuel Steam Generator
003	Existing	Unit 5 Fossil Fuel Steam Generator
004	Existing	Unit 4 Fossil Fuel Steam Generator
016	Existing	Coal and Ash Material Handling Activities for Coal-Fired Steam Generators
023	New	Limestone and Gypsum Material Handling Activities
024	New	CBO Fluidized Bed Combustor
025	New	CBO Feed Fly Ash Silo
026	New	CBO Product Fly Ash Storage Dome and Truck Loadout Silo

REGULATORY CLASSIFICATION

- The facility is a major source of hazardous air pollutants (HAP).
- The facility operates units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.
- The existing facility is subject to Power Plant Site Certification No. PA 77-09.

PROJECT HISTORY

Permit No. 0170004-013-AC authorized the installation of new selective catalytic reduction (SCR) systems on Units 4 and 5 to reduce nitrogen oxides (NO_X). The purpose of the project was to implement the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). It did not trigger PSD preconstruction review.

Permit No. PSD-FL-383 (Project No. 0170004-016-AC) superseded Permit No. 0170004-013-AC and authorized the following new equipment in addition to SCR systems: new low-NO_X burners (LNB) for Units 4 and 5; new wet flue gas desulfurization (FGD) systems for Units 4 and 5 to reduce sulfur dioxide (SO_2) and other acid gas emissions; a new alkali injection system for Units 4 and 5 to reduce sulfuric acid mist (SAM) emissions; upgraded electrostatic precipitators (ESP) for Units 4 and 5 to reduce particulate matter emissions; new stack configurations for Units 4 and 5; and a new carbon burn out unit. The purpose of the project was to implement the CAIR and CAMR and it was subject to PSD preconstruction review.

Permit No. PSD-FL-383A (Project No. 0170004-019-AC) revised the original permit to require operation of the wet FGD and SCR systems in response to the Environmental Protection Agency's revised 8-hour ozone standard.

Permit No. PSD-FL-383B (Project No. 0170004-022-AC) revised the original permit to: include a temporary alternate compliance demonstration for carbon monoxide emissions for Unit 5 until the continuous emissions monitoring system is installed during the outage to tie in the new wet FGD system and stack; correct as-built equipment descriptions for the gypsum storage and handling systems; acknowledge that the limestone crushing operations will be subject to the federal provisions in NSPS Subpart OOO of 40 CFR 60; and clarify the timeframes for compliance monitoring following completion of construction, startup and shakedown of the air pollution control systems.

This project, Permit No. PSD-FL-383C (Project No. 0170004-023-AC), revises the original permit to: authorize limited periods of shutdown of the alkali injection system for maintenance and repair; and clarify that the deadline for submitting an application to revise the Title V air operation permit is after completing the work for both units.

~~**RELEVANT DOCUMENTS**~~

~~The following relevant documents are not a part of this permit, but helped form the basis for this permitting action: the permit application and additional information received to make it complete; the draft permit package including the Department's Technical Evaluation and Preliminary Determination; publication and comments; the Department's BACT determinations and the Department's Final Determination.~~

CONTENTS

1. Permitting Authority: All documents related to PSD applications for permits to construct or modify emissions units shall be submitted to the Department's Bureau of Air Regulation in the Division of Air Resource Management at 2600 Blair Stone Road, MS #5505, Tallahassee, Florida, 32399-2400. Copies of all such applications shall also be submitted to each Compliance Authority.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's Southwest District Office at 13051 N. Telecom Parkway, Temple Terrace, FL 33637-0926.

3. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to the applicable requirements of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the appropriate forms provided in Rule 62-210.900, F.A.C. and follow the applicable permitting procedures as specified in the above regulations. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.

4. Source Obligation:

   (a) Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit.

   (b) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   (c) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   [Rule 62-212.400(12), F.A.C.]

5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rule 62-4.030 and Chapters 62-210 and 62-212, F.A.C.]

6. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after completing the work on both units and commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. [Rules 62-4.030, 62-4.050, 62-4.220 and Chapter 62-213.420, F.A.C.]

This section of the permit addresses the following emissions units.

EU No.	Emission Unit Description
003	Unit 5 is a fossil fuel-fired electric utility steam generator consisting of a pulverized coal, dry bottom, wall-fired boiler rated at 760 MW, which began commercial operation in 1984. Air pollution control equipment will include: low-NOx burners, selective catalytic reduction (SCR) systems, flue gas desulfurization (FGD) systems, alkali injection, and an electrostatic precipitator (ESP). The flue gas exhausts at 130° F with a volumetric flow rate of 2,205,195 acfm through a stack that is 30.5 feet in diameter and 550 feet tall. Units 4 and 5 share a common chimney with separate internal stack liners.
004	Unit 4 is a fossil fuel-fired, electric utility steam generator consisting of a pulverized coal, dry bottom, wall-fired boiler rated at 760 MW, which began commercial operation in 1982. Air pollution control equipment will include: low-NOx burners, selective catalytic reduction (SCR) systems, flue gas desulfurization (FGD) systems, alkali injection, and an electrostatic precipitator (ESP). The flue gas exhausts at 130° F with a volumetric flow rate of 2,205,195 acfm through a stack that is 30.5 feet in diameter and 550 feet tall. Units 4 and 5 share a common chimney with separate internal stack liners.
016	Material handling activities consist of the existing handling and storage of coal and ash for coal-fired electric utility steam generators.
024	The carbon burn-out (CBO) unit is a fluidized bed combustor that will reburn fly ash generated from Units 4 and 5 to produce low-carbon, low-ammonia fly ash material suitable for commercial use. The CBO unit is included in this subsection because the flue gas exhaust is directed back into the ductwork of Units 4 and 5 prior to the control equipment.

*{Permitting Note: Existing units EU-003, EU-004, and EU-016 are currently subject to the following applicable requirements: Power Plant Site Certification No. PA 77-09; 40 CFR 60, NSPS Subpart D (*fossil fuel-fired steam generators)*; NSPS Subpart Y (coal preparation plants); and Chapter 62-214, F.A.C. (Acid Rain Program). This permit does not affect these previous requirements. In accordance with Rule 62-212.400 (PSD), F.A.C., this project subjects these units to BACT determinations for the following pollutants: CO, PM/PM$_{10}$, SAM, and VOC. Final BACT determinations are presented in Appendix E of this permit. Emissions standards specified in this permit allow these units to avoid PSD preconstruction review for NO$_X$ and SO$_2$.*

AUTHORIZED CONSTRUCTION

1. Previous Permits:

   a. *Units 4 and 5*: Except for Permit No. 0170004-013-AC, the conditions of this permit supplement all previously issued air construction and operation permits for Units 4 and 5. Unless otherwise specified, these conditions are in addition to all other applicable permit conditions and regulations including: Power Plant Site Certification No. PA 77-09; 40 CFR 60, NSPS Subpart D (fossil fuel-fired steam generators); and Chapter 62-214, F.A.C. (Phase I and II of the Acid Rain Program). However, this permit supersedes Permit No. 0170004-013-AC for the construction of the selective catalytic reduction systems, which is now on the same construction schedule as the flue gas desulfurization systems.

   b. *Material Handling Activities (EU-016)*: The material handling activities for the existing coal-fired electric utility steam generators remain subject to the applicable permit conditions and regulations as specified by Permit No. 0170004-014-AC issued on December 15, 2006. That permit authorized modifications to the existing material handling activities and included the following primary regulations: Power Plant Site Certification No. PA 77-09; Permit No. PSD-FL-139; and 40 CFR 60, NSPS Subpart Y (coal preparation plants). This permit does not add any new requirements.

   [Permit Nos. 0170004-013-AC and 017004-014-AC; Application No. 0170004-016-AC; Rule 62-4.070(3), F.A.C.]

2. Emissions Reduction Projects: For Units 4 and 5, the permittee is required to make the following modifications to assure compliance with the new emissions limits listed below.
   a. *Low-NO_X Burners*: The permittee is required to install new low-NOx burners manufactured by Babcock & Wilcox (Model No. DRB-42) or equivalent. The preliminary design is for 54 burners per unit. The existing burner inlet system will be modified to allow even airflow distribution to the new burners.
   b. *SCR Systems*: The permittee is required to install new SCR systems to reduce NOx emissions. Each system will consist of the following basic components: an ammonia injection grid, a mixing grid, SCR reactor with catalyst modules, a urea-to-ammonia processing system, associated bulk storage systems, an automated control system, piping, electrical, and other ancillary equipment. As needed, urea will be converted into ammonia, which will be mixed to the proper concentration. Ammonia will be injected ahead of the SCR reactor, which will be installed upstream of the air heater for each unit. The ammonia will combine with NO_X in the presence of the catalyst in a reduction reaction to form nitrogen and water. The preliminary design is for 90% reduction in NO_X emissions with a maximum ammonia slip of 2 to 5 ppmv. The design also incorporates dampers and ductwork to provide the capability of bypassing the SCR system. The bypass is most commonly used to gradually heat or cool the catalyst structure to minimize thermal fatigue during startup and shutdown. ~~During catalyst maintenance and repair, the bypass would also allow access to the SCR reactor without requiring the complete shutdown of a unit.~~
   c. *FGD Systems*: The permittee is required to install new wet flue gas desulfurization (FGD) systems after the existing ESPs and induced draft fans to reduce SO_2 and other acid gas emissions. A limestone slurry will be injected into the FGD absorbers at design feed rate of approximately 352 gpm. The slurry will consist of approximately 25 to 30% solids and a specific gravity of 1.22. The preliminary design is for a 97% reduction in SO_2 emissions. In addition to the FGD absorbers, the systems will consist of limestone storage and handling, limestone preparation, limestone slurry injection, FGD blowdown, and gypsum dewatering, transfer and storage.
   d. *Stacks*: In conjunction with the emissions reduction projects, the permittee is authorized to construct a single new 550 feet tall chimney with separate internal stack liners for Units 4 and 5, one per unit. Each stack liner will have an internal diameter of 30.5 feet. The existing stacks will no longer be used. The required continuous emissions monitoring systems (CEMS) will be installed on each new stack liner.

   The above information is based on the preliminary design. As necessary, the permittee shall provide the Permitting and Compliance Authorities with updated information should the final design significantly change. [Application No. 0170004-016-AC; Rules 62-4.070(3), 62-4.080 and 62-212.300, F.A.C.]

3. BACT Controls: For Units 4 and 5, the permittee is required to perform the following work as the basis for the BACT determinations.
   a. *Alkali Injection Systems*: The permittee is required to install new alkali injection systems to reduce SAM emissions. The preliminary design for the alkali injection system is to use ammonia generated from the urea-to-ammonia processing system, which is part of the new SCR system. Ammonia will be injected into the flue gas through a uniform injection grid located after the boiler air heaters and proposed SCR reactor and before the existing ESP. The additional ammonia reacts with SO_3 to form salts (e.g., bisulfates), which will be removed by the ESP. The preliminary design is for an 85% reduction.
   b. *ESP*: The permittee is authorized to modify the existing ESPs to achieve the new PM/PM_{10} emissions standards. Some of this work may include the following: removing and replacing the precipitator roof; replacing the precipitator internals; replacing and upgrading the discharge electrodes to improve collection efficiency; as necessary, modifying the gas flow path deflectors at the inlet of the precipitator to improve the flow distribution; replacing the rapping system with top-mounted rappers to improve

performance; adjusting the plate spacing for improved collection efficiency; and reinforcing the precipitator box to account for increased transient pressures from the new induced draft fans. *{Permitting Note: The modifications are intended to improve the estimated collection efficiency to more than 99.5%.}*

[Application No. 0170004-016-AC; Rules 62-4.070(3), 62-212.300 and 62-212.400(PSD), F.A.C.]

4. CBO Unit: The permittee is authorized to install a new CBO fluidized bed combustor (Model No. 1500 or equivalent) with a nominal bed area of 1500 ft^2 that will reburn fly ash generated from Units 4 and 5 to produce low-carbon, low-ammonia fly ash material suitable for commercial use as an additive in Portland cement. The CBO unit also includes the following process equipment: hot cyclones to recycle fly ash back to the fluidized bed combustor; a heat recovery heat exchanger; cold cyclones to recover product fly ash; and a fabric filter to recover product fly ash. The flue gas exhaust shall be directed back into the ductwork of Units 4 and 5 prior to the air pollution control equipment such that emissions will be controlled when either unit or both units are in operation. The hot cyclones, cold cyclones and baghouse are considered process equipment and not air pollution control equipment because the equipment is used to separate the ash from the flue gas exhaust. The recovered ash is sold as a byproduct and the flue gas exhaust is directed back into the boiler ductwork for control. Details of the CBO process are provided in Subsection B, which regulates the material handling activities. [Application No. 0170004-016-AC; Rules 62-4.070(3), 62-212.300 and 62-212.400(PSD), F.A.C.]

PERFORMANCE REQUIREMENTS

5. Permitted Capacities:

   a. *Units 4 and 5*: The maximum heat input rates to Units 4 and 5 are 7200 MMBtu per hour per unit based on a 24-hour block average (midnight to midnight) and 6800 MMBtu per hour per unit based on a 30-day rolling average. Compliance shall be demonstrated by collecting the fuel feed rate and fuel heating values as monitored by the existing operating data monitoring system.

   b. *CBO Unit*: The maximum heat input rate to the CBO fluidized bed combustor is 95.6 MMBtu per hour based on a 24-hour block average.

   [Application No. 0170004-016-AC; Rules 62-4.070(3) and 62-212.300, F.A.C.]

6. Authorized Fuels:

   a. In addition to the currently authorized fuels, this air construction permit authorizes Units 4 and 5 to fire a blend of bituminous coal and sub-bituminous coal of up to 20% sub-bituminous coal upon issuance of this permit. Coal fuel blends shall not exceed a maximum sulfur content of 3.13% by weight.

   b. For startup, the CBO fluidized bed combustor will fire distillate oil with a maximum sulfur content of 0.5% by weight. Once the target operating temperature is achieved, fly ash from the boilers will be combusted.

   {Permitting Note: The current Title V air operation permit authorizes Units 4 and 5 to fire bituminous coal, a bituminous coal and bituminous coal briquette mixture, used oil, No. 2 fuel oil as a startup fuel, and natural gas as a startup and low-load flame stabilization fuel. Recently, the plant successfully tested a blend of approximately 80% bituminous coal with 20% Powder River Basin coal (sub-bituminous coal).}

   [Application No. 0170004-016-AC; Rule 62-4.070(3), F.A.C.]

7. Capacities and Restrictions: None of the emissions units in this subsection are restricted by hours of operation (8760 hours/year). [Application No. 0170004-016-AC; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS LIMITATIONS AND PERFORMANCE STANDARDS

8. Standards Based on Stack Tests: Including the emissions from the CBO unit, emissions from each Unit 4 or Unit 5 shall not exceed the following standards based on stack tests.
   a. *Ammonia Slip*: As determined by EPA Method CTM-027 (or equivalent), the ammonia slip shall not exceed 5 ppmv based on a 3-run test average conducted at permitted capacity.
   b. *PM/PM_{10} Emissions*: As determined by EPA Method 5 or 5b, PM emissions shall not exceed 0.030 lb/MMBtu and 216.0 lb/hour based on a 3-run test average conducted at permitted capacity.
   c. *SAM emissions*: As determined by EPA Method 8 or 8A, SAM emissions shall not exceed 0.009 lb/MMBtu and 64.8 lb/hour based on a 3-run test average conducted at permitted capacity. This standard applies at all times except during periods of maintenance and repair as authorized by this permit.
   d. *VOC Emissions*: As determined by EPA Method 25A, VOC emissions shall not exceed 0.004 lb/MMBtu and 28.8 lb/hour based on a 3-run test average conducted at permitted capacity. Optionally, EPA Method 18 may be conducted concurrently in order to deduct non-regulated VOC emissions such as methane and ethane.
   e. *Opacity*: As determined by EPA Method 9, the stack opacity shall not exceed 10% based on a 6-minute block average, except for one 6-minute period per hour of not more than 20%.

   [Rule 62-212.400(BACT), F.A.C.]
9. Standards Based on CEMS: Including the emissions from the CBO unit, emissions from Units 4 and 5 each shall not exceed the following standards based on data collected by the CEMS.
   a. *NO_X Emissions*: As determined by CEMS data, NO_X emissions shall not exceed 2,085 tons per year per unit based on a 12-month rolling average for all periods of operation including startup, shutdown and malfunction. [Application No. 0170004-016-AC; Rules 62-4.070(3), 62-4.080 and 62-212.400(12), F.A.C.]
   b. *SO_2 Emissions*: As determined by CEMS data, SO_2 emissions shall not exceed 0.27 lb/MMBtu of heat input based on a 30-day rolling average for all periods of operation including startup, shutdown and malfunction. As determined by CEMS data, SO_2 emissions shall not exceed 1944.0 lb/hour per unit based on a 24-hour block average excluding startup, shutdown and malfunction of the FGD system. [Application No. 0170004-016-AC; Rules 62-4.070(3), 62-4.080 and 62-212.400(12), F.A.C.]
   c. *CO Emissions (Interim)*: As determined by CEMS data, CO emissions shall not exceed 0.17 lb/MMBtu of heat input based on a 30-day rolling average excluding periods of startup, shutdown and malfunction. As determined by CEMS data, CO emissions shall not exceed 1156.0 lb/hour based on a 30-day rolling average for all periods of operation including startup, shutdown and malfunction. [Rule 62-212.400 (BACT), F.A.C.]
   d. *CO Emissions (Final)*: Within 24 months of commencing commercial operation of each unit with the new low-NO_X burners, the permittee shall submit an application proposing a revised (lower) final BACT standard. The final standard shall be based on actual CO emissions data collected for initial operation after completing installation of the new low-NO_X burners. There may be separate standards proposed for different fuels. [Rule 62-212.400(BACT), F.A.C.]
10. Circumvention: No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly. The SCR and FGD systems shall operate as necessary to comply with the emissions standards of this permit. The alkali injection system and ESP shall operate in accordance with the automated controls system as determined by subsequent performance and compliance testing and in accordance with the conditions of this permit.

[Rules 62-210.650 and 62-212.400(BACT), F.A.C.]

11. Excess Emissions - Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

12. Excess Emissions - Allowed: In accordance with Rule 62-210.700(6), F.A.C., excess emissions due to startup, shutdown or malfunction have been considered in establishing the sets of CEMS-based emissions standards of this permit. ~~No other periods of excess emissions are authorized.~~ With regard to SAM emissions, the alkali injection system is currently shared by Units 4 and 5 and the system must be shutdown to conduct some maintenance and repairs. The following additional conditions apply to the shared alkali injection system:

    a. *Additional SAM Testing*: Within 18 months of issuance of this permit revision, the permittee shall conduct additional SAM emissions tests (at least three, 1-hour test runs) on at least one unit without the alkali injection system in operation while firing lower sulfur "substitute coal". The SAM emissions standard shall not apply during these information-gathering tests. The purpose of the tests are to determine the SAM emissions rate (lb/MMBtu) while firing "substitute coal" with the alkali injection system offline. The permittee shall submit a test report in accordance with the requirements of this permit and specifically identify whether the units are capable of complying with the SAM emissions limit while firing the tested "substitute coal". Each test report shall also include the results from all previous tests conducted for such purposes. If the sulfur content of the "substitute coal" increases, subsequent SAM tests may be conducted as necessary in accordance with this condition. *{Permitting Note: Currently, "substitute coal" is available at the plant and used for Units 1 and 2. Although the permitted maximum sulfur content of this coal is approximately 1.3% by weight (2.1 lb SO_2/MMBtu), the actual sulfur content is less than 1% by weight. When firing "substitute coal", reductions in SAM emissions by the wet FGD system may be sufficient to demonstrate compliance with the SAM emissions standard.}*

    b. *Preventive Maintenance*: To minimize malfunctions of the alkali injection system and resulting excess SAM emissions, the permittee shall conduct annual preventive maintenance.

        (1) The preventive maintenance shall be scheduled for a period when at least one unit (Unit 4 or Unit 5) is down for a scheduled outage, which occurs approximately every 18 months per unit. Whenever possible, the scheduled outages shall be staggered such that only one unit will be in an outage each year to accommodate the required annual preventive maintenance.

        (2) When conducting the required preventative maintenance of the alkali injection system, the permittee may operate no more than one unit while firing "substitute coal" without the alkali injection system in operation for no more than 240 hours per calendar year. If stack testing demonstrates compliance with the SAM emissions standard while firing "substitute coal" for a given sulfur content without the alkali injection system in operation, the hours of operation while firing that coal shall not count towards this operational restriction.

    c. *Repair*: The following conditions apply to malfunctions of the alkali injection system. A malfunction is defined as, "Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner."

        (1) The permittee shall maintain a list and inventory of spare parts associated with the shared alkali injection equipment to facilitate quick repairs.

        (2) When a malfunction occurs, the permittee shall immediately investigate to determine the corrective action required. For malfunctions that will require an extended period of time to repair, the permittee

shall begin preparations to fire "substitute coal". When initially evaluating a given malfunction and performing the repair, Units 4 and/or 5 may be operated without the alkali injection system for no more than 72 hours; thereafter, Units 4 and/or 5 shall begin firing "substitute coal" to continue operating while the plant makes the repair.

(3) The alkali injection system shall not be offline (including the malfunctions) for more than a total of 480 hours per calendar year to evaluate malfunctions and conduct repairs. This operational restriction shall include: authorized hours of firing normal coal for initial evaluation and repair (up to 72 hours per event); and authorized hours of operation firing "substitute coal" that has not yet demonstrated compliance with the SAM emissions standard. If stack testing demonstrates compliance with the SAM emissions standard while firing "substitute coal" for a given sulfur content without the alkali injection system in operation, the hours of operation while firing that coal shall not count towards this operational restriction.

d. *Purpose:* The purpose of this condition is to provide operational flexibility to conduct timely maintenance and repair on the alkali injection system shared by Units 4 and 5 while minimizing excess SAM emissions. Once compliance is demonstrated for firing "substitute coal" with a given sulfur content, periodic testing is not required except as allowed by Rule 62-297.310(7)(b), F.A.C. (Special Compliance Tests). In addition, the compliant sulfur content for "substitute coal" shall be established based on the following equation:

$\% S_{Comp} = (\%S_{Tested})\ (SAM_{Limit})\ /\ (SAM_{Tested})$

Where:

$\%S_{Comp}$ = Maximum percent sulfur content by weight that would demonstrate compliance

$\%S_{Tested}$ = Actual percent sulfur content by weight fired during stack test

SAM_{Limit} = Permitted SAM emissions limit, 0.009 lb/MMBtu

SAM_{Tested} = Actual SAM emissions rate in lb/MMBtu based on stack test

Example: Stack testing shows an actual SAM emissions rate of 0.0085 lb/MMBtu when firing substitute coal with a sulfur content of 0.98% by weight and the alkali injection system offline. Therefore, the maximum sulfur content of "substitute coal" considered demonstrated would be:

$\% S_{Comp}$ (SC) = (0.98% S) (0.009 lb/MMBtu) / (0.0085 lb/MMBtu) = 1.04% sulfur by weight

Therefore, if "substitute coal" is fired with an actual sulfur content equal to or less than the maximum sulfur content as calculated above ($\%S_{Comp}$), then the hours while firing that coal do not count towards the operational restrictions specified for maintenance and repair. If "substitute coal" is fired with an actual sulfur content higher than the calculated value ($\%S_{Comp}$), then the hours while firing that coal do count towards the operational restrictions specified for maintenance and repair.

[Rule 62-210.700(6), F.A.C.]

CONTINUOUS EMISSIONS MONITORING REQUIREMENTS

13. Existing CEMS/COMS: For Units 4 and 5, the permittee shall continue to calibrate, operate, and maintain continuous monitoring equipment to measure and record opacity, NO_X and SO_2 in terms of the applicable standards. The permittee shall either relocate the existing CEMS to the new stack configurations or replace the monitoring systems. Due to the wet stack, the existing COMS shall be relocated or new COMS installed in the ductwork after the ESP and prior to the wet FGD system. Each COMS and CEMS shall be installed such that representative measurements of emissions or process parameters from the facility are obtained. The

monitors shall be installed, operated and maintained in accordance with the existing requirements of 40 CFR 60.45, as well as the provisions of the federal acid rain program. [Rule 62-4.070(3), F.A.C.]

14. CO CEMS Installation: For Units 4 and 5, the permittee shall properly install, calibrate, operate and maintain CEMS to measure and record CO emissions in the terms of the applicable standard. Each CEMS shall be installed such that representative measurements of emissions or process parameters from the facility are obtained. The permittee shall locate the CEMS by following the procedures contained in the applicable performance specification of 40 CFR Part 60, Appendix B. The permittee shall install each CEMS required by this permit and conduct the appropriate performance specification for each CEMS within 60 calendar days of completing installation of the low-NOx burners and achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup. As an option for Unit 5 because of construction delays, the permittee may postpone installation of the CO CEMS until the Unit 5 exhaust is tied into the new FGD system and stack. If this option is selected, the permittee shall conduct an initial CO stack test in accordance with EPA Method 10 within 60 days of completing installation of the low-NOx burners. The tests shall demonstrate compliance with the numerical portion of the CO emissions standard based on the 3-run test average. In addition, CEMS data collected from similar Unit 4 shall be used as a surrogate to show compliance until the Unit 5 CEMS is installed. Based on the Unit 4 CEMS data, the Compliance Authority may require special compliance tests in accordance with Rule 62-297.310(7)(b), F.A.C. This period of alternate compliance shall not exceed 180 days from completing installation of the low-NOx burners. The permittee shall install and certify the CO CEMS within 60 days following the tie-in of the new FGD system and permanent stack. [Rules 62-4.070(3), 62-297.310(7)(b) and 62-212.400(BACT), F.A.C.]

15. Compliance by CEMS: Compliance with the standards for opacity and emissions of CO, NO_X, and SO_2 shall be demonstrated with data collected from the required continuous monitoring systems. Within 60 days of completing construction on the related air pollution control device for each unit, the permittee shall certify proper operation of each required monitor. The permittee shall comply with the conditions of Appendix F (Standard Continuous Monitoring Requirements) of this permit as the compliance method for the corresponding emissions standards. The permittee shall begin demonstrating compliance with the CO CEMS emissions standards once a monitor is certified. The permittee shall begin demonstrating compliance with the opacity, NO_X and SO_2 COMS/CEMS emissions standards after completing the initial shakedown of the associated air pollution control device, but no later than 180 days after certifying the corresponding COMS/CEMS. During the period between certification of the SO_2 CEMS and completing initial shakedown of the FGD system, the units shall comply with the SO_2 emissions standards in the current Title V permit based on compliance by CEMS (Condition B.5a), but may fire a coal fuel blend in compliance with the maximum fuel sulfur level specified in this air construction permit (Condition 6, Subsection 3A). Within 10 days of completing initial shakedown for an air pollution control device, the permittee shall notify the compliance authority of the following: the air pollution control device; the date that shakedown was completed; the monitoring data being collected to demonstrate continuous compliance; and the status of the other air pollution control devices. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

PRELIMINARY PERFORMANCE TESTING REQUIREMENTS

16. Preliminary SAM Performance Tests: Within 60 days after completing construction on the pollution control systems, the permittee shall conduct a series of preliminary performance tests on either unit to determine the SAM emissions rate under a variety of operating scenarios. The purpose of the tests is to document the impact of alkali injection on reducing SAM emissions and results in the development of correlation/curves between injection rates, operating conditions and emissions. When collecting data during the preliminary SAM performance tests, the permittee is exempt from the SAM emissions standards of this permit.

a. For each set of operating conditions being evaluated, the permittee shall conduct at least a 1-hour test run to determine SAM emissions. At least nine test runs shall be conducted to evaluate the effect of SAM emissions on parameters such as: the SO_2 emissions rate prior to the SCR catalyst, the unit load, the flue gas flow rate, the alkali injection rate, the current catalyst oxidation rate, and the operating level of the FGD system.

b. Tests shall be conducted with the fuel blends and load rates that are representative of the actual operating ranges intended for Units 4 and 5. Sufficient tests shall be conducted to establish the SAM emissions rates for the following scenarios: bypass of the SCR reactor, SCR reactor in service without alkali injection, and SCR reactor in service under varying operating conditions and levels of alkali injection.

c. At least 15 days prior to initiating the performance tests, the permittee shall submit a test notification, preliminary test schedule and test protocol to the Bureau of Air Regulation and the Compliance Authority.

d. Within 45 days following the last test run conducted, the permittee shall provide a report summarizing the emissions tests and results. All SAM emissions test data shall be provided with this report.

e. Within 45 days following the submittal of the ~~emissions~~ performance test report and no later than 90 days following the last test run conducted, the permittee shall submit an operating protocol and report summarizing the following: identify each set of operating conditions evaluated; identify each operating parameter evaluated; identify the relative influence of each operating parameter; describe how the automated control system will adjust the alkali injection rate based on the selected parameters; identify the frequency with which operational parameters will be reevaluated and adjusted within the automated control system; provide a description of the algorithm used for the automated control system or a series of related performance curves; and provide details for calculating and estimating the SAM emissions rate based on the level of alkali injection and operating conditions. The preliminary performance tests shall be used to set the alkali injection control system and estimate SAM emissions.

f. The permittee shall operate the alkali injection system in accordance with the operating protocol determined by the performance tests. The permittee may request that additional performance tests be conducted to establish new operating conditions for the alkali injection system due to changes with the fuel blends, the SCR catalyst, or other circumstances.

[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

COMPLIANCE TESTING REQUIREMENTS

17. Common Testing Requirements: All required emissions tests shall be conducted in accordance with the requirements specified in Appendix D (Common Testing Requirements) of this permit. [Rules 62-204.800 and 62-297.100, F.A.C.; and 40 CFR 60, Appendix A]

18. Test Methods: Any required stack tests shall be performed in accordance with the following methods.

EPA Method	Description of Method and Comments
1 - 4	Methods for Determining Traverse Points, Velocity, Flow Rate, Gas Analysis, and Moisture Content These methods shall be performed as necessary to support other methods.
5 or 5b	Method for Determining Particulate Matter Emissions
6C	Method for Determining SO_2 Emissions (Instrumental)
7E	Method for Determining NOx Emissions (Instrumental)
8 or 8A	Method for Determining Sulfuric Acid Mist (SAM) Emissions

EPA Method	Description of Method and Comments
9	Method for Determining Opacity Observations
10	Method for Determining Carbon Monoxide Emissions (Instrumental) The method shall be based on a continuous sampling train.
18	Method for Determining Gaseous Organic Compound Emissions (Gas Chromatography) Concurrently with EPA Method 25A, EPA Method 18 may be used as an optional method to deduct emissions of methane and ethane from the THC emissions measured by Method 25A.
19	Methods for Determining NO_X, PM, and SO_2 Mass Emission Rates
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source This is an EPA conditional test method with a minimum detection limit of 1 ppm. Other equivalent methods may be used.

The above methods are specified in Appendix A of 40 CFR 60 and are adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-4.070(3), 62-204.800(8) and 62-212.400(BACT), F.A.C.; 40 CFR 60, Appendix A]

19. Compliance Tests: In accordance with the following requirements, the permittee shall have stack tests conducted to demonstrate compliance with the emissions standards specified in this permit for ammonia slip, PM, SAM and VOC.

   a. *Initial Tests*: Within 60 days after completing construction on the pollution control systems, initial compliance tests shall be conducted to determine emissions of ammonia slip, opacity, PM and VOC. Within 120 days after completing construction on the pollution control systems and after completing the preliminary SAM performance tests, initial compliance tests shall be conducted to determine SAM emissions. At least one boiler shall be tested with the CBO unit also in operation. If the CBO unit is not yet in service at the time of the initial tests, separate compliance tests to determine PM and SAM emissions shall be conducted on at least one boiler with the CBO unit in operation. All initial tests shall be conducted with the emissions units operating at permitted capacity (within at least 90% of 7200 MMBtu/hour); otherwise, this permit shall be modified to reflect the true maximum capacity of each unit as constructed should the permitted capacity be unattainable. If initial equipment problems prevent operation at permitted capacity, the initial tests may be repeated to demonstrate compliance at permitted capacity. [Rules 62-212.400(BACT) and 62-297.310(7), F.A.C.; 40 CFR 60.8]

   b. *Subsequent Tests*: During each federal fiscal year (October 1^{st} to September 30^{th}), Units 4 and 5 shall be tested to determine emissions of ammonia slip, opacity, PM, and SAM. During the 12 months prior to renewal of the operation permit, Units 4 and 5 shall be tested to demonstrate compliance with the VOC emission standards. For each pollutant, at least one boiler shall be tested with the CBO unit also in operation. The Department may require the permittee to repeat some or all of the initial stack tests after substantial replacement or repair of any air pollution control or process equipment.

   c. *Test Fuel*: Initial compliance tests shall be conducted with the highest sulfur content representative of the actual coal blends being fired. Within 60 days of determining that the fuel sulfur content of the actual coal blends fired have increased by 0.5% by weight or more from the highest tested sulfur content that demonstrated compliance, the permittee shall conduct new tests to determine emissions of opacity, PM and SAM. For purposes of this condition, the fuel sulfur content shall be based on an average of the as-fired fuel samples for 30 successive operating days. Once initial compliance has been demonstrated at the higher fuel sulfur levels (2.63% to 3.13% sulfur by weight), subsequent tests shall be conducted using a fuel with a sulfur content that is representative of the actual coal blends being fired. [Rules 62-4.070(3), 62-212.400(BACT) and 62-297.310, F.A.C.]

d. *Test Capacity*: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Except for the initial tests, if it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit (7200 MMBtu/hour based on a 24-hour average). [Rules 62-212.400(BACT) and 62-297.310, F.A.C.]

20. Operational Data for Tests: For each test run, the permittee shall monitor and record the following information: fuel feed rate; heat input rate; sulfur content of fuel; the ammonia injection rate of the SCR control system; the limestone slurry injection rate of the FGD control system; alkali injection rate of the alkali injection system; flue gas oxygen content (%); CO, NO_X, and SO_2 CEMS emissions data; and opacity data. [Rules 62-297.310 and 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

21. Stack Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Compliance Authority on the results of each such test. The required test report shall be filed with the Compliance Authority as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Compliance Authority to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the specified in Rule 62-297.310(8), F.A.C. The stack test report shall also indicate all required operational data collected during each test run. [Rule 62-297.310(8), F.A.C.]

22. Malfunction Notifications: If temporarily unable to comply with any condition of the permit due to breakdown of equipment (malfunction) or destruction by hazard of fire, wind or by other cause, the permittee shall immediately (within one working day) notify the Compliance Authority. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. If requested by the Compliance Authority, the owner or operator shall submit a quarterly written report describing the malfunction. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

23. Fuel Monitoring – Units 4 and 5: Using the existing operating data system, the permittee shall continuously monitor each fuel to determine the heat input rates to Units 4 and 5. The heat input rates shall be calculated from the amounts of fuel fired and the higher heating value (HHV) of each fuel as determined by vendor certifications or the regular sampling and analysis required by the current Title V permit. Data shall be reduced to 1-hour blocks, 24-hour blocks (midnight-to-midnight), and 30-day rolling averages (average of all the 1-hour blocks for 30 operating days). [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

24. Fuel Monitoring – CBO Unit: During any compliance test and when requested by the Compliance Authority, the permittee shall monitor and record the heat input rate to the CBO Unit from the amount of ash burned and the heating value of the ash. [Rule 62-212.400(BACT), F.A.C.]

25. Control Device – Parametric Monitoring:

a. *SCR System*: The permittee shall continuously monitor and record the ammonia injection rate of the SCR control system. Data shall be reduced to 1-hour block averages. [Rule 62-4.070(3), F.A.C.]

b. *FGD System*: The permittee shall continuously monitor and record the limestone slurry injection rate of the FGD control system. Data shall be reduced to 1-hour block averages. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

c. *Alkali Injection System*: The permittee shall continuously monitor and record the alkali injection rate of the alkali injection system. Data shall be reduced to 1-hour block averages. Operation of the alkali injection system shall be determined by the automated control system, which shall be set in accordance with the preliminary performance and compliance tests for SAM emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

d. *ESP*: The permittee shall continuously monitor and record the opacity in the ductwork just after the ESP for use as part of the Compliance Assurance Monitoring Plan under Title V. Operation of the ESP shall be based upon COMS data collected during satisfactory PM emissions compliance tests. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

This section of the permit addresses the following emissions unit.

EU No.	Emission Unit Description
023	Limestone and Gypsum Material Handling Activities

Process Description

The FGD systems will include limestone storage and handling, limestone preparation, limestone slurry injection, and gypsum dewatering, transfer and storage. The limestone handling system will receive, store, size and transfer limestone to the FGD system's limestone preparation equipment. It will receive limestone delivered to the plant by rear dump trucks unloading into aboveground truck unloading feeders with integral hoppers. The system will consist of: a conveyor to transfer limestone received from truck unloading feeders; unloading and the stacking belt conveyors to transfer limestone to a covered storage pile; a portal scraper reclaimer and an emergency reclaim feeder; a reclaim conveyor to transfer limestone from the storage pile to a crusher feed belt conveyor, which transfers limestone to a crusher building for limestone sizing; a plant feed belt conveyors and silo feed belt conveyors to transfer limestone to the day silos.

The plant feed conveyor will be equipped with a diverter gate and will supply limestone to the first limestone day silo (Silo B) directly via a chute and to the other limestone day silos (Silos A & C) using a reversible conveyor. Limestone silos will be equipped with a pulse-jet fabric filter dust collection system. Dust collectors will be provided at each of the truck unloading feeders. A dust collection system will be provided for the crusher building. A water-fog dust suppression system will be provided at the discharge point of the reclaim conveyor and at the tail end of the crusher feed conveyor to suppress the limestone dust formation.

The limestone preparation system includes wet ball mill grinding systems to produce limestone slurry. Filtrate-recycle water from the FGD system will be used to prepare the limestone slurry to conserve make-up water. Fugitive dust emissions are minimized, by enclosures and the addition of water for the slurry.

The gypsum slurry from the FGD system will be delivered by bleed pumps to the dewatering system, which will consist of a filter feed tank, hydro-cyclones, vacuum belt filters, vacuum pumps, filtrate tanks, filtrate pumps, lined piping, and associated valves. The incoming gypsum slurry will contain approximately 18 to 22% suspended solids. Using a series of hydro-cyclones and three horizontal vacuum belt filters, the dewatering system will remove water until the slurry contains approximately 90% solids. Filtrate removed from the slurry will be stored and pumped back to the limestone preparation system or the absorber module. The de-watering system will be located inside a building. Fugitive dust emissions are negligible because the system is enclosed and wet.

A collecting belt conveyor collects dewatered gypsum from the vacuum belt filters in the dewatering system. Under normal operating conditions, this conveyor will feed gypsum onto a system of conveyors, which transfers the gypsum onto a gypsum handling pad or to the future wallboard plant. The gypsum handling pad will be located northeast of the dewatering facility and will be used primarily (until the future adjacent wallboard facility is built) to store the gypsum until it can be transferred offsite for beneficial use or disposal. In addition, the gypsum handling pad may be used to store "off-specification" gypsum if needed. Fugitive dust emissions will be minimal because the dewatered gypsum still contains approximately 10% water.

AUTHORIZED CONSTRUCTION

1. Equipment: The permittee is authorized to construct the following processes to support the FGD system: limestone storage and handling, limestone preparation, limestone slurry injection, and gypsum dewatering, transfer and storage. [Application No. 0170004-016-AC; Rules 62-4.070(3), 62-212.300 and 62-212.400(PSD), F.A.C.]

2. Air Pollution Control Equipment and Techniques: To comply with the standards of this permit, the permittee

shall design, install, operate and maintain the following air pollution control equipment.

Process Activity	Emissions Point No.	Control Device	Outlet Dust Loading Specification
Dry Limestone Handling System			
Limestone conveyors (general)	---	covered	---
Limestone reclaim conveyor (discharge)	---	dust suppressant	---
Dump trucks	---	covered	---
Two truck unloading feeders w/integral hoppers	EP-1A EP-1B	one dust collector per hopper	0.010 grains/dscf
Limestone storage	---	covered pile	---
Limestone crushing and sizing	EP-2	enclosed building w/baghouse	0.010 grains/dscf
Limestone silo feed conveyors and 3 Limestone day silos	EP-3	one dust collector~~s~~	0.010 grains/dscf
~~3 Limestone day silos~~	~~EP-4~~	~~baghouse~~	~~0.010 grains/dscf~~
Gypsum Dewatering System			
Gypsum dewatering system	---	enclosure/wet	---
Gypsum Handling System			
Gypsum handling system	---	enclosure/wet	---
Gypsum Handling Pad	---	water spray	---

Initial and replacement bags shall be selected based on the above design outlet dust loading specification. As part of the application to revise the Title V air operation permit to incorporate this air construction permit, the permittee shall submit the final design flow rates for each dust collector and baghouse. [Application No. 0170004-016-AC; Rules 62-4.070(3), 62-212.300 and 62-212.400(BACT), F.A.C.]

3. Fugitive Dust Emissions: The dry limestone handling and storage operations shall be enclosed to the extent practicable and confined to prevent fugitive dust emissions. During the construction period, fugitive dust emissions shall be minimized by techniques such as covering, confining and/or the application of water or dust suppressants to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

EMISSIONS LIMITATIONS AND PERFORMANCE STANDARDS

4. Capacities: None of the emissions units in this subsection are restricted by hours of operation (8760 hours/year). *{Permitting Note: For informational purposes, maximum limestone processing rate is estimated at 100 tons per day.}* [Application No. 0170004-016-AC; Rule 62-210.200(PTE), F.A.C.]

5. Opacity Standard: As determined by EPA Method 9, visible emissions from each baghouse and dust collector exhaust point shall not exceed 5% opacity based on a 6-minute average. [Application No. 0170004-016-AC; Rule 62-212.400(BACT), F.A.C.]

6. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

7. NSPS Subpart OOO Provisions: The limestone crushing activities are subject to the applicable requirements in NSPS Subpart OOO of 40 CFR 60. See Appendix G of this permit.

COMPLIANCE TESTING REQUIREMENTS

8. Initial Compliance Tests: Each baghouse exhaust shall be tested to demonstrate initial compliance with the specified opacity standard. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the unit. [Rule 62-297.310(7)(a)1, F.A.C.]

9. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each baghouse exhaust point shall be tested to demonstrate compliance with the specified opacity standard. [Rule 62-297.310(7)(a)4, F.A.C.]

10. Test Notification: At least 15 days prior to the date on which each formal compliance test is to begin, the permittee shall notify the Compliance Authority of: the date, time, and place of the test; and the contact person who will be responsible for coordinating and having the test conducted. [Rule 62-297.310(7)(a)9, F.A.C.]

11. Test Method: Opacity tests shall be conducted in accordance with EPA Method 9, which is described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Tests shall also comply with the applicable requirements of Rule 62-297.310, F.A.C. summarized in Appendix D (Common Testing Requirements) of this permit. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

12. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C. The minimum observation period for a visible emissions compliance test shall be 30 minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. The permittee shall record the actual processing rate for the emissions unit being tested. [Rules 62-297.310(4) and (5), F.A.C.]

13. Common Testing Requirements: All required emissions tests shall be conducted in accordance with the requirements specified in Appendix D (Common Testing Requirements) of this permit. The minimum observation period for a visible emissions compliance test shall be 30 minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. The permittee shall record the actual processing rate for the emissions unit being tested. [Rule 62-297.310, F.A.C.]

RECORDS AND REPORTS

14. Final Design Notification: Within 90 days of completing the FGD system design, provide the final details for the limestone and gypsum material handling activities including a process flow diagram and all control equipment specifications. It may be necessary to modify this air construction permit. [Application No. 0170004-016-AC; Rule 62-4.070(3), F.A.C.]

15. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Compliance Authority on the results of each such test. The required test report shall be filed with the Compliance Authority as soon as practical, but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Compliance Authority to determine if the test was properly conducted and the test results properly computed. [Rule 62-297.310(8), F.A.C.]

16. Operational Records: The owner or operator shall maintain the following records on site to demonstrate compliance with the specifications and limitations of this subsection.

    a. Records of the design outlet dust loading specifications for new and replacement fabric filter bags; and

    b. For each month, record the total limestone processed for the month and the previous 12 months.

    All records shall be made available to the Department and Compliance Authority upon request. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

C. Material Handling Activities for CBO System

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
025	**CBO Feed Fly Ash Silo**
026	**CBO Product Fly Ash Storage Dome and Truck Loadout Silo**

Process Description

Fly ash from Units 4 and 5 will be conveyed pneumatically to the CBO feed fly ash silo (EU-025). The silo will vent through a baghouse prior to discharge to the atmosphere. Fly ash will then be fed from the silo to the fluidized bed combustor (EU-024) for processing. Fly ash from the fluidized bed combustor will be separated from the exhaust gases by hot cyclones and directed to a heat exchanger to cool the product and recover heat. Thermal energy recovered from the CBO process will be used to heat condensate from the Unit 4 and 5 low-pressure feed water systems. The cooled exhaust gas will be routed through a cold cyclone and fabric filter to remove residual product fly ash before being returned to the inlet ductwork of Units 4 and 5 pollution control equipment (SCR, FGD, ESP and alkali injection systems).

Product fly ash separated by the cold cyclone and fabric filter will be sent to a surge bin with a portion of the product fly ash being returned to the fluidized bed combustor for temperature control. The remaining product ash is pneumatically conveyed to the product fly ash storage dome (EU-026) or directly to a truck load-out silo (also EU-026). The product fly ash storage dome will vent through a baghouse prior to discharging to the atmosphere. Particulate emissions captured during the truck load-out process will be routed to the truck load-out silo which will vent through a baghouse. Trucks will travel on paved roads within the plant and exit the plant for delivery offsite. Fugitive particulate matter emissions associated with product fly ash truck traffic will be controlled by maintaining the roads and periodic watering as needed.

AUTHORIZED CONSTRUCTION

1. CBO System: The permittee is authorized to construct a carbon burnout system consisting of the following major components: a fluidized bed combustor (EU-024) with hot cyclones to recycle ash back to the fluidized bed combustor, a heat recovery heat exchanger, cold cyclones to recover product ash and a fabric filter to recover product ash; a feed fly ash silo (EU-025, CBO-001); a product fly ash storage dome and a product fly ash truck loadout silo (EU-026). The system is designed for a maximum ash process rate of 75 tons per hour. For the fluidized bed combustor, the hot cyclones, cold cyclones and baghouse are considered process equipment and not air pollution control devices because the equipment is used to separate ash from the flue gas exhaust, which is then directed back into the boiler ductwork for emissions control. [Application No. 0170004-016-AC; Rules 62-4.070(3), 62-212.300 and 62-212.400(PSD), F.A.C.]

2. Air Pollution Control Equipment: To comply with the standards of this permit, the permittee shall design, install, operate, and maintain the following air pollution control equipment.

EU No.	Emissions Unit	Emissions Point No.	Control Device	Flow Rate	Outlet Dust Loading Specification
025	CBO Feed Fly Ash Silo	CBO-001	Baghouse	3040 acfm	0.010 grains/dscf
026	CBO Product Storage Dome	CBO-002	Baghouse	7600 acfm	0.010 grains/dscf
026	CBO Product Truck Loadout	CBO-003	Baghouse	7600 acfm	0.010 grains/dscf

Initial and replacement bags shall be selected based on the above design outlet dust loading specification. [Application No. 0170004-016-AC; Rules 62-4.070(3), 62-212.300 and 62-212.400(BACT), F.A.C.]

3. Fugitive Dust Emissions: The CBO system shall be enclosed to the extent practicable and confined to prevent fugitive dust emissions. During the construction period, fugitive dust emissions shall be minimized by techniques such as covering, confining and/or the application of water or dust suppressants to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

EMISSIONS LIMITATIONS AND PERFORMANCE STANDARDS

4. Capacities and Restrictions: None of the emissions units in this subsection are restricted by hours of operation (8760 hours/year). The maximum ash processing rate for the CBO system shall not exceed 320,000 tons of product ash during any consecutive 12 months. [Application No. 0170004-016-AC; Rule 62-210.200(PTE), F.A.C.]
5. Opacity Standard: As determined by EPA Method 9, visible emissions from each baghouse exhaust point shall not exceed 5% opacity based on a 6-minute average. [Application No. 0170004-016-AC; Rule 62-212.400(BACT), F.A.C.]
6. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

COMPLIANCE TESTING REQUIREMENTS

7. Initial Compliance Tests: Each baghouse exhaust shall be tested to demonstrate initial compliance with the specified opacity standard. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the unit. [Rule 62-297.310(7)(a)1, F.A.C.]
8. Annual Compliance Tests: During each federal fiscal year (October 1^{st} to September 30^{th}), each baghouse exhaust point shall be tested to demonstrate compliance with the specified opacity standard. [Rule 62-297.310(7)(a)4, F.A.C.]
9. Test Notification: At least 15 days prior to the date on which each formal compliance test is to begin, the permittee shall notify the Compliance Authority of: the date, time, and place of the test; and the contact person who will be responsible for coordinating and having the test conducted. [Rule 62-297.310(7)(a)9, F.A.C.]
10. Test Method: Opacity tests shall be conducted in accordance with EPA Method 9, which is described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Tests shall also comply with the applicable requirements of Rule 62-297.310, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]
11. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. The permittee shall record the actual ash processing rate for the emissions unit being tested. [Rules 62-297.310(4) and (5), F.A.C.]

RECORDS AND REPORTS

12. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Compliance Authority on the results of each such test. The required test report shall be filed with the Compliance Authority as soon as practical, but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Compliance Authority to determine if the test was properly conducted and the test results properly computed. [Rule 62-297.310(8), F.A.C.]

13. Operational Records: The owner or operator shall maintain the following records on site to demonstrate compliance with the specifications and limitations of this subsection.

    a. Records of the design outlet dust loading specifications for new and replacement fabric filter bags; and

    b. For each month, record the total product ash processed for the month and the previous 12 months.

    All records shall be made available to the Department and Compliance Authority upon request. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

D. Units 4 and 5 – Temporary Trial Period with up to 50% Sub-bituminous Coal

This section of the permit addresses a temporary trial period for the following emissions units.

EU No.	Emission Unit Description
004	Unit 4 is a fossil fuel-fired, electric utility steam generator
003	Unit 5 is a fossil fuel-fired, electric utility steam generator

TEMPORARY AUTHORIZATION AND RESTRICTIONS

1. Trial Coal Blend: For Units 4 and 5, the permittee is temporarily authorized to fire trial coal blends with greater than 20% sub-bituminous coal by weight (including Powder River Basin coal), but not more than 50% sub-bituminous coal by weight. The maximum sulfur content of such coal blends shall not exceed 3.13% by weight. The preliminary schedule is to conduct the trial before installation of the additional control systems. The purpose is to gather operational and emissions data to evaluate overall impacts in support of a future permanent request to fire bituminous/sub-bituminous coal blends. [Application No. 0170004-016-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

2. Trial Test Burn Duration: The trial coal blends shall only be fired in existing Units 4 and 5 and shall be fired in a similar manner to the bituminous coal currently in use at the plant. The permittee shall provide at least a one-day advance notice (by phone, fax, or email) to the Compliance Authority prior to the initial firing of any trial coal blend. Once any trial coal blend is fired, the permittee shall complete the trial burn within 90 calendar days. No more than 150,000 tons of the trial coal blends shall be burned during the trial burn period. In addition, all trial burns shall be completed prior to the expiration date of this permit. Within five calendar days of completing the trial burn, the permittee shall notify the Compliance Authority (by phone, fax, or email) that the trial burn has been completed. [Application No. 0170004-016-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS LIMITING AND PERFORMANCE STANDARDS

3. Performance Requirements: The permittee shall provide the Compliance Authority with a preliminary schedule for conducting the trial burn and performance tests and shall update this schedule as necessary. During the trial burn, the permittee shall comply with all terms and conditions in the current Title V air operation permit. If the trial burn results in operation that is not in accordance with the conditions of the Title V permit or the test protocol, the performance testing will cease as soon as possible. The permittee shall immediately notify the Compliance Authority (by phone, fax, or email) of any non-compliance issue. The trial burn shall not resume until appropriate actions have been taken to correct the problem. [Application No. 0170004-016-AC; Rule 62-4.070(3), F.A.C.]

4. Fugitive Dust: The permittee shall take reasonable precautions to prevent fugitive dust emissions from the unloading, storage, and handling of trial coal blends. These shall be the same reasonable precautions specified in the most recent Title V air operation permit to prevent fugitive dust emissions from the unloading, storage, and handling of the coal blends currently in use at the plant. [Application No. 0170004-016-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

MONITORING AND TESTING

5. Baseline Emissions: Baseline emissions shall be determined by the continuous monitoring systems for opacity, NO_X, and SO_2 emissions when firing bituminous coal at permitted capacity. For each boiler that will fire the trial coal blend, the permittee shall conduct tests at permitted capacity for emissions of CO and PM. Permitted capacity is defined as 90 to 100 percent of the maximum heat input rate allowed by the permit (7200 MMBtu/hour based on a 24-hour average). Test results shall be reported in units of lb/MMBtu and lb/hour. If tests are conducted after installation of the new CO CEMS, baseline CO emissions shall be

determined by data collected by the CEMS. If available, existing data may be used for baseline data. [Rule 62-4.070(3), F.A.C.]

6. Trial Coal Blend Emissions: Emissions from firing the trial coal blend at permitted capacity shall be determined by the continuous monitoring systems for opacity, NO_X, and SO_2 coal blends. For each boiler that will fire the trial coal blends, the permittee shall conduct tests at permitted capacity for emissions of CO and PM. Permitted capacity is defined as 90 to 100 percent of the maximum heat input rate allowed by the permit (7200 MMBtu/hour based on a 24-hour average). If only one boiler fires the trial coal blend during the trial burn period, that unit shall conduct two series of tests to determine emission levels of PM, SAM, and VOC for the trial coal blend. Test results shall be reported in units of lb/MMBtu and lb/hour. If tests are conducted after installation of the new CO CEMS, baseline CO emissions shall be determined by data collected by the CEMS. The permittee shall obtain a sample of each trial coal blend fired. A proximate and ultimate analysis shall be provided for each sample taken. [Rule 62-4.070(3), F.A.C.]

7. Monitoring: The permittee shall conduct the following monitoring when firing the trial coal blend.

   a. The permittee shall record the amount and blend ratio of each trial coal blend delivered to the plant. A "certificate of analysis" (including the proximate and ultimate analysis) shall be retained for each delivery of trial coal blend.

   b. On at least three separate days, the permittee shall take samples of the trial coal blend being fired. A proximate and ultimate analysis shall be provided for each sample taken. Samples taken on different emissions testing days may satisfy this requirement.

   c. The permittee shall maintain daily records of the boiler operations including: the blend ratio as fired; the fuel mass firing rate; the heat input rate; steam production, temperature and pressure; and the MW generated.

   d. The permittee shall monitor and record the ESP secondary voltage and secondary current and calculate and record the total ESP secondary power input.

   e. The permittee shall continuously monitor and record opacity, NO_X, and SO_2 with the existing CEMS. If the trial burn is conducted after installation of the CO CEMS, CO emissions shall also be continuously monitored.

   [Rule 62-4.070(3), F.A.C.]

8. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
1 - 4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5 or 5b	Determination of Particulate Matter (PM) Emissions
8 or 8A	Method for Determining Sulfuric Acid Mist (SAM) Emissions
9	Method for Determining Opacity Observations
10	Method for Determining Carbon Monoxide Emissions (Instrumental) The method shall be based on a continuous sampling train.
18	Method for Determining Gaseous Organic Compound Emissions (Gas Chromatography) Concurrently with EPA Method 25A, EPA Method 18 may be used as an optional method to deduct emissions of methane and ethane from the THC emissions measured by Method 25A.
19	Methods for Determining NO_X, PM, and SO_2 Mass Emission Rates
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)

Tests shall also be conducted in accordance with the requirements specified in Appendix D (Common Testing Requirements) of this permit. The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

9. Notifications: The permittee shall provide the Compliance Authority with a written preliminary schedule for conducting any emissions tests (by letter, fax, or email). The preliminary schedule shall be updated as necessary. The permittee shall provide the Compliance Authority with at least 5 days advance notice (by phone, fax, or email) prior to conducting any emissions tests. [Rule 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

10. Trial Burn Report: Within 60 days of completing the trial burn period, the permittee shall submit a final report summarizing the trial burn to the Bureau of Air Regulation and the Compliance Authority. The trial burn report shall include, but not be limited to, the following information: actual schedule and overall description of the trial burn; summary of trial coal blends evaluated (amounts delivered; blend ratio; and proximate/ultimate analyses); discussion of operational issues with the trial coal blends (coal unloading, coal handling, coal storage, coal firing, fugitive dust, soot blowing, ESP performance and adjustments, ash handling, and ash storage); comparison of baseline operations versus operation with the trial coal blends; evaluation of current equipment compatibility with the trial coal blends; summary of boiler operating data and continuous emissions monitoring data; comparison of baseline emissions with emissions from firing trial coal blends (short-term and long-term); and a discussion of emissions changes as described in Appendix C of 40 CFR 60. [Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400, F.A.C.]

E. Units 1, 2, 4 and 5 – Temporary Trial Period with Fuel Additive

This section of the permit addresses a temporary trial period for the following emissions units.

EU No.	Emission Unit Description
001	Unit 1 is a fossil fuel-fired, electric utility steam generator
002	Unit 2 is a fossil fuel-fired, electric utility steam generator
003	Unit 5 is a fossil fuel-fired, electric utility steam generator
004	Unit 4 is a fossil fuel-fired, electric utility steam generator

TEMPORARY AUTHORIZATION AND RESTRICTIONS

1. Fuel Additive: For Units 1, 2, 4 and 5, the permittee is temporarily authorized to apply a fuel additive (Environmental Energy Services, Inc.) based on calcium nitrate to currently authorized coal blends (bituminous coal, bituminous coal with coal briquettes, bituminous coal with sub-bituminous coal). The preliminary schedule is to conduct the trial before installation of the additional control systems. The purpose of the trial period is to evaluate the impact of the fuel additive on unit performance, slagging, emissions levels, and loss on ignition (LOI). The preliminary design is to spray the fuel additive on the coal prior to combustion. Preliminary estimates are for a rate of 3 to 30 gph (total to all feeders) of 500 to 1000 ppm of active concentrate onto the coal. Various applications rates will be tested. The purpose is to gather operational and emissions data to evaluate overall impacts in support of a future permanent request to use this fuel additive. *{Permitting Note: The vendor expects a 30% reduction in CO emissions, a 30% reduction in PM emissions, a 20% reduction in NOx emissions, and a 10% reduction in opacity.}* [Application No. 0170004-016-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

2. Trial Test Burn Duration: The fuel additive shall only be applied to coal fired in the existing units. The permittee shall provide at least a one-day advance notice (by phone, fax, or email) to the Compliance Authority prior to the initial application of the fuel additive. Once the fuel additive is initially applied, the permittee shall complete all trial burns within 90 calendar days. Within five calendar days of completing the trial burn period, the permittee shall notify the Compliance Authority (by phone, fax, or email) that the trial burn period has been completed. [Application No. 0170004-016-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS LIMITING AND PERFORMANCE STANDARDS

3. Performance Requirements: The permittee shall provide the Compliance Authority with a preliminary schedule for conducting trial burns and performance tests and shall update this schedule as necessary. During each trial burn, the permittee shall comply with all terms and conditions in the current Title V air operation permit. If a trial burn results in operation that is not in accordance with the conditions of the Title V permit or the test protocol, the trial burn shall cease as soon as possible. The permittee shall immediately notify the Compliance Authority (by phone, fax, or email) of any non-compliance issue. The trial burn shall not resume until appropriate actions have been taken to correct the problem. [Application No. 0170004-016-AC; Rule 62-4.070(3), F.A.C.]

MONITORING AND TESTING

4. Emissions - Baseline: Baseline emissions shall be determined by the continuous monitoring systems for opacity and NO_X, and SO_2 emissions when firing representative coal fuel blends at permitted capacity. For each boiler that will fire coal with the fuel additive, the permittee shall conduct impaction plate tests at permitted capacity for baseline PM emissions and use a portable analyzer to document baseline CO emissions. Permitted capacity is defined as 90 to 100 percent of the maximum heat input rate allowed by the

permit (7200 MMBtu/hour based on a 24-hour average). Test results shall be reported in units of lb/MMBtu and lb/hour. [Rule 62-4.070(3), F.A.C.]

5. Emissions with Fuel Additive: Emissions shall be determined by the continuous monitoring systems for opacity, NO_X, and SO_2 emissions when firing coal blends with fuel additive at permitted capacity. For each boiler that will fire coal with the fuel additive, the permittee shall conduct impaction plate tests at permitted capacity for baseline emissions of particulate matter (PM) and use a portable analyzer to document baseline CO emissions. Permitted capacity is defined as 90 to 100 percent of the maximum heat input rate allowed by the permit. Test results shall be reported in units of lb/MMBtu and lb/hour. [Rule 62-4.070(3), F.A.C.]

6. Monitoring of Operations: For each trial, the permittee shall conduct the following monitoring: the type, amount, and heat input of fuel fired; the boiler feedwater flow rates, boiler feedwater temperatures to the economizer, flue gas oxygen levels, and electrical outputs; the fuel additive injection rates and fuel additive concentrations; LOI, ash porosity, iron content, and slag viscosity; and continuously monitor and record opacity, NOx and SO_2 with the existing COMS and CEMS. For comparison purposes, the permittee shall identify the current corresponding baseline monitoring values for bituminous coal firing or collect baseline data during the trial burn period. [Rule 62-4.070(3), F.A.C.]

7. Notifications: The permittee shall provide the Compliance Authority with a written preliminary schedule for conducting any emissions tests (by letter, fax, or email). The preliminary schedule shall be updated as necessary. The permittee shall provide the Compliance Authority with at least 5 days advance notice (by phone, fax, or email) prior to conducting any emissions tests. [Rule 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

8. Trial Burn Report: Within 60 days of completing the trial burn, the permittee shall submit a final report summarizing the trial burn to the Bureau of Air Regulation and the Compliance Authority. The final report shall provide the following: the actual schedule and overall description of the trial burn; any operational issues related to the fuel additive; a comparison of baseline operation versus operation with the fuel additive; an evaluation of equipment compatibility with fuel additive; a summary and comparison of continuous emissions and opacity monitoring data; a summary and comparison of all operational parameters; a summary and comparison of emissions test results; a comparison of continuously monitored emissions; a discussion of the impacts on LOI, ash porosity, iron content, and slag viscosity; and a discussion of emissions changes as described in Appendix C of 40 CFR 60.

   [Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400, F.A.C.]

F. Units 4 and 5 – Temporary Trial Period with up to 30% Petroleum Coke

This section of the permit addresses a temporary trial period for the following emissions units.

EU No.	Emission Unit Description
003	Unit 5 is a fossil fuel-fired, electric utility steam generator
004	Unit 3 is a fossil fuel-fired, electric utility steam generator

TEMPORARY AUTHORIZATION AND RESTRICTIONS

1. Trial Coal Blend: Upon commercial operation of all air pollution control equipment (low-NO_X burners, SCR systems, FGD systems, alkali injection systems, and ESP improvements) and satisfactorily demonstrating compliance with the required initial tests, this air construction permit authorizes Units 4 and 5 to fire a trial coal blend of bituminous coal with up to 30% petroleum coke by weight. The maximum sulfur content of the trial coal blend shall not exceed 3.13% by weight. This permit authorizes a trial period to fire such blends and does not authorize the permanent firing of petroleum coke. The purpose is to gather operational and emissions data to evaluate overall impacts in support of a future permanent request to fire coal blends with petroleum coke. [Application No. 0170004-016-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

2. Trial Test Burn Duration: Trial coal blends shall only be fired in existing Units 4 and 5 and shall be fired in a manner similar to bituminous coal. The permittee shall provide at least a one-day advance notice (by phone, fax, or email) to the Compliance Authority prior to the initial firing of the first trial coal blend. Once the first trial coal blend is fired, the permittee shall complete all trial burns within 90 calendar days. No more than a total of 150,000 tons of trial petroleum coke/coal blends shall be fired during the trial burn period. In addition, all trial burns shall be completed prior to the expiration date of this permit. Within five calendar days of completing the trial burn period, the permittee shall notify the Compliance Authority (by phone, fax, or email) that the trial burn period has been completed. [Application No. 0170004-016-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS LIMITING AND PERFORMANCE STANDARDS

3. Performance Requirements: The permittee shall provide the Compliance Authority with a preliminary schedule for conducting trial burns and performance tests and shall update this schedule as necessary. During each trial burn, the permittee shall comply with all terms and conditions in the current Title V air operation permit. If a trial burn results in operation that is not in accordance with the conditions of the Title V permit or the test protocol, the trial burn shall cease as soon as possible. The permittee shall immediately notify the Compliance Authority (by phone, fax, or email) of any non-compliance issue. The trial burn shall not resume until appropriate actions have been taken to correct the problem. [Application No. 0170004-016-AC; Rule 62-4.070(3), F.A.C.]

4. Fugitive Dust: The permittee shall take reasonable precautions to prevent fugitive dust emissions from the unloading, storage, and handling of the trial coal blends. These shall be the same reasonable precautions specified in the current Title V air operation permit to prevent fugitive dust emissions from the unloading, storage, and handling of bituminous coal currently in use at the plant. [Application No. 0170004-016-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

MONITORING AND TESTING

5. Baseline Emissions: Baseline emissions shall be determined by the continuous monitoring systems for opacity and CO, NO_X, and SO_2 emissions when firing bituminous coal at permitted capacity. For each boiler that will fire a petroleum coke/coal blend, the permittee shall conduct tests at permitted capacity for PM, SAM and VOC emissions. Permitted capacity is defined as 90 to 100 percent of the maximum heat input rate allowed by the permit (7200 MMBtu/hour based on a 24-hour average). Test results shall be reported in

units of lb/MMBtu and lb/hour. Compliance tests conducted after completing the construction authorized by this permit may be used for the baseline emissions data. [Rule 62-4.070(3), F.A.C.]

6. Trial Coal Blend Emissions: Emissions shall be determined by the continuous monitoring systems for opacity and CO, NO_X, and SO_2 emissions when petroleum coke/coal blends at permitted capacity. For each boiler that fires a petroleum coke/coal blend, the permittee shall conduct tests at permitted capacity for PM, SAM and VOC emissions. Permitted capacity is defined as 90 to 100 percent of the maximum heat input rate allowed by the permit (7200 MMBtu/hour based on a 24-hour average). Test results shall be reported in units of lb/MMBtu and lb/hour. During each required emission test, the permittee shall obtain a sample of the petroleum coke/coal blend as fired. A proximate and ultimate analysis shall be provided for each sample taken. If only one boiler fires the trial coal blend during the trial burn period, that unit shall conduct two series of tests to determine emission levels of PM, SAM, and VOC for the trial coal blend. [Rule 62-4.070(3), F.A.C.]
7. Monitoring: When firing trial coal bends, the permittee shall conduct the following monitoring.
   a. The permittee shall record the amount and blend ratio of each petroleum coke/coal blend delivered to the plant. A "certificate of analysis" (including the proximate and ultimate analysis) shall be retained for each delivery of petroleum coke/coal blend.
   b. For each petroleum coke/coal blend, the permittee shall take a sample of the blend as fired. A proximate and ultimate analysis shall be provided for each sample taken. Samples taken on different emissions testing days may satisfy this requirement.
   c. The permittee shall maintain daily records of the boiler operations including: the petroleum coke/blend ratio fired; the fuel mass firing rate; the heat input rate; steam production, temperature and pressure; and the MW generated.
   d. The permittee shall monitor and record the ESP secondary voltage and secondary current and calculate and record the total ESP secondary power input.
   e. The permittee shall continuously monitor and record opacity, CO, NO_X, and SO_2 with existing monitoring systems.

   [Rule 62-4.070(3), F.A.C.]
8. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
1 - 4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5 or 5b	Determination of Particulate Matter (PM) Emissions
8 or 8A	Method for Determining Sulfuric Acid Mist (SAM) Emissions
9	Method for Determining Opacity Observations
10	Method for Determining Carbon Monoxide Emissions (Instrumental) The method shall be based on a continuous sampling train.
18	Method for Determining Gaseous Organic Compound Emissions (Gas Chromatography) Concurrently with EPA Method 25A, EPA Method 18 may be used as an optional method to deduct emissions of methane and ethane from the THC emissions measured by Method 25A.
19	Methods for Determining NO_X, PM, and SO_2 Mass Emission Rates
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)

Tests shall also be conducted in accordance with the requirements specified in Appendix D (Common

Testing Requirements) of this permit. The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

9. Notifications: The permittee shall provide the Compliance Authority with a written preliminary schedule for conducting any emissions tests (by letter, fax, or email). The preliminary schedule shall be updated as necessary. The permittee shall provide the Compliance Authority with at least 5 days advance notice (by phone, fax, or email) prior to conducting any emissions tests. [Rule 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

10. Emissions Tests Reports: The permittee shall prepare and submit reports for all emissions tests in accordance with the requirements specified in Appendix D (Common Testing Requirements) of this permit. For each test run, the report shall also indicate the following: the petroleum coke/blend ratio, the fuel firing rate, the heat input rate, the average ESP secondary power input, the opacity, the CO emission rate, the NOx emission rate, and the SO_2 emission rate. [Rule 62-297.310(8), F.A.C.]

11. Trial Burn Report: Within 60 days of completing the trial burn, the permittee shall submit a final report summarizing the trial burn to the Bureau of Air Regulation and the Compliance Authority. The trial burn report shall include, but not be limited to, the following information: actual schedule and overall description of the trial burn period; summary of petroleum coke/coal blends evaluated (amounts delivered, blend ratio, and proximate/ultimate analyses); discussion of operational issues of petroleum coke/coal (coal unloading, coal handling, coal storage, coal firing, fugitive dust, soot blowing, ESP performance and adjustments, ash handling, and ash storage); comparison of baseline operations versus operation with petroleum coke/coal blend; evaluation of current equipment compatibility with petroleum coke/coal blend; summary of continuous emissions monitoring data; summary of boiler operating data; summary of emissions test results, actual test schedule, and procedures used; comparison of baseline emissions with emissions from firing petroleum coke/coal blend (short-term and long-term); and a discussion of emissions changes as described in Appendix C of 40 CFR 60. [Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400, F.A.C.]

CONTENTS

CITATION FORMATS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

GLOSSARY OF COMMON TERMS

° F: degrees Fahrenheit

acfm: actual cubic feet per minute

ARMS: Air Resource Management System (Department's database)

BACT: best available control technology

Btu: British thermal units

CAM: compliance assurance monitoring

CEMS: continuous emissions monitoring system

cfm: cubic feet per minute

CFR: Code of Federal Regulations

CO: carbon monoxide

COMS: continuous opacity monitoring system

DEP: Department of Environmental Protection

Department: Department of Environmental Protection

dscfm: dry standard cubic feet per minute

EPA: Environmental Protection Agency

ESP: electrostatic precipitator (control system for reducing particulate matter)

EU: emissions unit

F.A.C.: Florida Administrative Code

F.D.: forced draft

F.S.: Florida Statutes

FGR: flue gas recirculation

Fl: fluoride

ft^2: square feet

ft^3: cubic feet

gpm: gallons per minute

gr: grains

HAP: hazardous air pollutant

Hg: mercury

I.D.: induced draft

ID: identification

kPa: kilopascals

lb: pound

MACT: maximum achievable technology

MMBtu: million British thermal units

MSDS: material safety data sheets

MW: megawatt

NESHAP: National Emissions Standards for Hazardous Air Pollutants

NO_X: nitrogen oxides

NSPS: New Source Performance Standards

O&M: operation and maintenance

O_2: oxygen

Pb: lead

PM: particulate matter

PM_{10}: particulate matter with a mean aerodynamic diameter of 10 microns or less

PSD: prevention of signifi9cant deterioration

psi: pounds per square inch

PTE: potential to emit

RACT: reasonably available control technology

RATA: relative accuracy test audit

SAM: sulfuric acid mist

scf: standard cubic feet

scfm: standard cubic feet per minute

SIC: standard industrial classification code

SNCR: selective non-catalytic reduction (control system used for reducing emissions of nitrogen oxides)

SO_2: sulfur dioxide

TPH: tons per hour

TPY: tons per year

UTM: Universal Transverse Mercator coordinate system

VE: visible emissions

VOC: volatile organic compounds

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), F.S., the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the F.S. or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, F.S.. Such evidence

shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.
11. This permit is transferable only upon Department approval in accordance with F.A.C. Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology (CO, PM/PM_{10}, SAM and VOC);
    b. Determination of Prevention of Significant Deterioration (applies); and
    c. Compliance with New Source Performance Standards (Subparts A, Dc and OOO in 40 CFR 60).
14. The permittee shall comply with the following:
    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
    c. Records of monitoring information shall include:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

COMMON CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(Definitions), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

RECORDS AND REPORTS

10. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]
11. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(3), F.A.C.]

COMMON TESTING REQUIREMENTS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the facility.

GENERAL COMPLIANCE TESTING REQUIREMENTS

1. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]
2. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]
3. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
4. Applicable Test Procedures [Rule 62-297.310(4), F.A.C.]
   a. *Required Sampling Time.*
      (1) Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
      (2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
         (a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
         (b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.
         (c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
   b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.
   c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.
   d. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance

with the schedule shown in Table 297.310-1.

e. *Allowed Modification to EPA Method 5.* When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

5. Determination of Process Variables [Rule 62-297.310(5), F.A.C.]

a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

6. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E. [Rule 62-297.310(6), F.A.C.]

a. *Permanent Test Facilities.* The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

b. *Temporary Test Facilities.* The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

c. *Sampling Ports.*

(1) All sampling ports shall have a minimum inside diameter of 3 inches.

(2) The ports shall be capable of being sealed when not in use.

(3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

(4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

(5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

d. *Work Platforms.*

(1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

(2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

(3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

(4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the

sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform.*

(1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

(2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

f. *Electrical Power.*

(1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

(2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support.*

(1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

(a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

(b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

(c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

(2) A complete monorail or dual rail arrangement may be substituted for the eyebolt and bracket.

(3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

7. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required. [Rule 62-297.310(7), F.A.C.]

a. *General Compliance Testing.*

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

(a) Did not operate; or

(b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,

4. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   (a) Visible emissions, if there is an applicable standard;
   (b) Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
   (c) c. Each NESHAP pollutant, if there is an applicable emission standard.
5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.
7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.
8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

b. *Special Compliance Tests.* When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

c. *Waiver of Compliance Test Requirements.* If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of paragraph 62-297.310(7)(b), F.A.C., shall apply.

RECORDS AND REPORTS

8. <u>Test Reports [Rule 62-297.310(8), F.A.C.]</u>

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

b. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

c. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information.

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

SUMMARY OF FINAL BACT DETERMINATIONS

PROJECT DESCRIPTION

Progress Energy Florida, Inc. operates the existing Crystal River Power Plant, which is located north of Crystal River and west of U.S. 19 in Citrus County, Florida. The plant consists of four coal-fired steam generating units, natural draft cooling towers, helper mechanical draft cooling towers, coal and ash handling facilities, and relocatable diesel-fired generators. The following changes will occur as a result of this project.

- To provide full flexibility in implementing the federal cap and trade program for NO_X and SO_2 emissions under CAIR, the plant will install new low-NOx burners, new SCR systems, new FGD systems, and new stack configurations for Units 4 and 5.
- In conjunction with the proposed control equipment, the new control equipment will allow the flexibility to fire additional fuel blends (sub-bituminous coal and petroleum coke) and recognize the actual maximum heat input rates for Units 4 and 5 as 7200 MMBtu per hour.
- The plant will install a new carbon burn-out (CBO) system that will reburn fly ash generated at this plant to recover the remaining heating value in this material and minimize the onsite landfilling of fly ash.
- The plant will conduct a trial burn to evaluate a new fuel additive intended to reduce slagging and improve emissions performance.

The combination of new fuel blends and control equipment will result in PSD-significant emissions increases of CO, PM/PM_{10}, SAM, and VOC. The Department's preliminary determinations of the Best Available Control Technologies (BACT) for these pollutants are based on: the design of the new low-NOx burners and good combustion practices (CO, PM/PM_{10}, and VOC); modifications to the existing ESPs (PM/PM_{10} and SAM); and new alkali injection systems (SAM).

FINAL BACT DETERMINATIONS

In accordance with Rule 62-212.400(6), F.A.C., the Department establishes the following standards as BACT for CO, PM/PM_{10}, SAM, and VOC emissions.

Unit 4 (EU-004), Unit 5 (EU-003) and CBO Fluidized Bed Combustor (EU-024) [f]

Pollutant	BACT Standard [g]	Averaging Period	Compliance Method
Ammonia Slip	5 ppmv	3-run test average	CTM-027 (or equivalent)
CO [a] (Interim)	0.17 lb/MMBtu excluding SU/SD/M 1156.0 lb/hour including SU/SD/M	30-day rolling average	CEMS Data
Opacity [b]	10% opacity, except for one 6-minute block per hour up to 20% opacity	6-minute block	EPA Method 9
PM/PM_{10} [c]	0.030 lb/MMBtu and 216.0 lb/hour	3-run test average	EPA Methods 5 or 5b
SAM [d]	0.009 lb/MMBtu and 64.8 lb/hour	3-run test average	EPA Methods 8 or 8A
VOC [e]	0.004 lb/MMBtu and 28.8 lb/hour	3-run test average	EPA Method 25A

Notes:

a. Within 24 months of commencing commercial operation of each unit with the new low-NO_X burners, the permittee shall submit an application proposing a revised (lower) final BACT standard. The final standard shall be based on actual CO emissions data collected for initial operation after completing installation of the new low-NO_X burners. There may be separate standards proposed for different fuels.

b. Due to concerns regarding moisture interference from the wet stack conditions caused by the FGD system, COMS were not required on the new stack.

c. The Department notes that this control strategy directly reduces PM/PM_{10} emissions as well as the formation of $PM_{2.5}$ in the environment when combined with the other proposed control systems (SCR systems designed for low ammonia slip; alkali injection to reduce sulfuric acid mist emissions; and FGD systems to minimize precursors known to contribute to formation of $PM_{2.5}$). The permittee shall continuously monitor and record the opacity in the ductwork just after the ESP for use as part of the Compliance Assurance Monitoring Plan under Title V. Operation of the ESP shall be based upon COMS data collected during satisfactory PM emissions compliance tests.

d. Operation of the alkali injection system shall be determined by the automated control system, which shall be set in accordance with the preliminary performance and compliance tests for SAM emissions. This standard applies at all times except as specified for authorized periods of preventive maintenance and repair.

e. Concurrently with EPA Method 25A, EPA Method 18 may be used as an optional method to deduct emissions of methane and ethane from the THC emissions measured by Method 25A.

f. The CBO fluidized bed combustor is also subject to the following applicable NSPS Subpart Dc provisions for boilers: the firing of fuel with no more than 0.5% sulfur by weight percent based on a certification from the fuel supplier (applies at all times, including periods of startup, shutdown, and malfunction); and no more than 20% opacity based on a 6-minute average, except for one 6-minute period per hour of not more than 27% opacity (applies at all times, except during periods of startup, shutdown, or malfunction). Since the flue gas exhaust from the CBO unit is directed back into the boiler ductwork for control, the CBO unit will achieve the same standards as Units 4 and 5, which are more stringent than the applicable NSPS.

g. "SU" means startup; "SD" means shutdown; and "M" means malfunction.

Limestone/Gypsum Material Storage and Handling (EU-023)

Limestone is the reactant for the FGD systems, which will produce gypsum as a byproduct. The following control equipment and techniques are determined to be BACT for minimizing dust emissions from the related material handling and storage activities.

- To the extent practical, all limestone conveyors will be enclosed to confine dust emissions.
- The initial storage of limestone will be in a covered storage pile.
- The portal scraper reclaimer and an emergency reclaim feeder will be located inside a limestone storage building.
- Limestone will be crushed and sized inside a crusher building, which will include a dust collection system.
- The three (possibly four) limestone silos will be equipped with pulse-jet fabric filter dust collection systems.
- Insertable dust collectors will be installed at each of the truck unloading feeders and at each of the loading points of the silo feed conveyors.
- A water-surfactant blend dust suppression system will be provided at the discharge point of the transfer conveyor and at the head end of the unloading conveyor to treat the limestone before it is loaded onto the belt of the stacking conveyor.
- Wet ball mill grinding systems will produce the limestone slurry for the FGD system. Fugitive dust emissions will be minimized by the addition of water for the slurry.
- The dewatering system will be located inside a building. Fugitive dust emissions will be negligible because the system is enclosed and wet.
- Fugitive dust emissions from dewatered gypsum will be minimal because it still contains 10% water. Gypsum storage piles will be watered as necessary to prevent fugitive dust.
- Bags for all dust collection systems shall be selected based on the above design outlet dust loading specification of no more than 0.010 grains per acf of exhaust. All replacement filter bags and cartridges shall meet this design specification.
- Visible emissions from each dust collector and fabric filter shall not exceed 5% opacity.

CBO Feed Ash Silo (EU-025) and Product Ash Storage (EU-026)

Fly ash from Units 4 and 5 will be conveyed pneumatically to the CBO feed fly ash silo (EU-025). Ash will be fed from this silo to the fluidized bed combustor (EU-024) for processing. Exhaust from the feed fly ash silo will vent through a baghouse prior to discharge to the atmosphere. Product ash will be pneumatically conveyed to storage (EU-026) in either the product fly ash storage dome or directly to a truck load-out silo, which will each vent to a separate baghouse. In addition, particulate emissions captured during the truck load-out process will be routed to the truck load-out silo for control by the baghouse. The following control equipment and techniques are determined to be BACT for minimizing dust emissions from the related material handling and storage activities.

- Dust emissions from the transfer of ash will be controlled by full enclosure throughout the CBO process.
- Bags for all dust collection systems shall be selected based on the above design outlet dust loading specification of no more than 0.010 grains per acf of exhaust. All replacement filter bags and cartridges shall meet this design specification.
- Visible emissions from each dust collector and fabric filter shall not exceed 5% opacity.
- Trucks will travel on paved roads within the plant and exit the plant for delivery offsite. Fugitive particulate matter emissions associated with product fly ash truck traffic will be controlled by maintaining the roads and periodic watering as needed.

The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit for the original project.

Unit 4 (EU-004) and Unit 5 (EU-003) are subject to the following requirements for continuous emissions monitoring systems (CEMS).

CEMS OPERATION PLAN

1. CEMS Operation Plan: The permittee shall create and implement a facility-wide plan for the proper installation, calibration, maintenance, and operation of each CEMS required by this permit. The permittee shall submit the CEMS Operation Plan to the Bureau of Air Monitoring and Mobile Sources for approval at least 60 days prior to CEMS installation. The CEMS Operation Plan shall become effective 60 days after submittal or upon its approval. If the CEMS Operation Plan is not approved, the permittee shall submit a new or revised plan for approval. [Rule 62-4.070(3), F.A.C.]

   {Permitting Note: The Department maintains both guidelines for developing a CEMS Operation Plan and example language that can be used as the basis for the facility-wide plan required by this permit. Contact the Emissions Monitoring Section of the Bureau of Air Monitoring and Mobile Sources at 850/488-0114.}

MONITORS, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

2. Existing CEMS: Existing Units 4 and 5 have CEMS currently installed. The permittee shall also continue to meet the applicable performance specifications and quality assurance procedures for these systems. [Rule 62-4.070(3), F.A.C.]

3. Span Values and Dual Range Monitors: The permittee shall set appropriate span values for the CEMS based on the emissions standards and range of operation. If necessary, the permittee shall install dual range monitors in accordance with the CEMS Operation Plan. [Rule 62-4.070(3), F.A.C.]

4. Moisture Correction: If necessary, the permittee shall install a system to determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). [Rule 62-4.070(3), F.A.C.]

5. Continuous Flow Monitor: For compliance with mass emission flow rate standards, the permittee shall install a continuous flow monitor to determine the stack exhaust flow rate. The flow monitor shall be certified pursuant to 40 CFR Part 60, Appendix B, Performance Specification 6. Alternatively, the permittee may install a fuel flow monitor and use an appropriate F-Factor computational approach to calculate stack exhaust flow rate. [Rules 62-212.400 and 62-4.070(3), F.A.C.]

   {Permitting Note: The CEMS Operation Plan will contain additional CEMS-specific details and procedures for installation.} [Rule 62-4.070(3), F.A.C.]

6. Performance Specifications: The permittee shall evaluate the "acceptability" of each CEMS by conducting the appropriate performance specification. CEMS determined to be "unacceptable" shall not be considered "installed" for purposes of meeting the timelines of this permit. For carbon monoxide, use Performance Specification 4 or 4A (as appropriate) in Appendix B of 40 CFR 60. [Rule 62-4.070(3), F.A.C.]

7. Quality Assurance: The permittee shall follow the quality assurance procedures of 40 CFR Part 60, Appendix F. For carbon monoxide, the required relative accuracy test assessment (RATA) tests shall be performed using EPA Method 10 in Appendix A of 40 CFR Part 60. [Rule 62-4.070(3), F.A.C.]

CALCULATION APPROACH FOR SIP COMPLIANCE

8. CEMS for Compliance: Once adherence to the applicable performance specification for each CEMS is demonstrated, the permittee shall use the CEMS to demonstrate compliance with the applicable emission standards as specified by this permit. [Rules 62-4.070(3) and 62-212.400, F.A.C.]

9. CEMS Data: Each CEMS shall monitor and record emissions during all operations and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments, and span adjustments. [Rule 62-4.070(3), F.A.C.]

10. Operating Hours and Operating Days: For purposes of this Appendix, the following definitions shall apply. An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for

more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit. [Rule 62-4.070(3), F.A.C.]

11. Valid Hourly Averages: Each CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

    a. Hours that are not operating hours are not valid hours.

    b. For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

    [Rule 62-4.070(3), F.A.C.]

12. Calculation Approaches: The permittee shall implement the calculation approach specified by this permit for each CEMS, as follows:

    a. *24-hour Block Average.* Compliance shall be determined after each 24-hour block by calculating the arithmetic average of all valid hourly averages occurring within that block averaging period.

    b. *30-day Rolling Average.* Compliance shall be determined after each operating day by calculating the arithmetic average of all valid hourly averages occurring within that day and the prior 29 operating days.

    c. *12-month Rolling Average.* Compliance shall be determined after each operating month by calculating the arithmetic average of all valid hourly averages occurring within that day and the prior 29 operating days.

    [Rule 62-4.070(3), F.A.C.]

13. Minimum Valid Hours: At least one valid hourly average shall be used to calculate the emissions over any block averaging period specified by this permit. One valid hourly average shall be sufficient to calculate the emissions over any block averaging period. [Rule 62-4.070(3), F.A.C.]

14. Data Exclusion for SIP Compliance: As per the procedures in this condition, limited amounts of CEMS emissions data may be excluded from the corresponding compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions replace the provisions in Rule 62-210.700(1), F.A.C.

    a. *Excess Emissions.* For purposes of SIP-based limits, some data collected during periods of SIP-based excess emissions (startup, shutdown, and malfunction) may be excluded from compliance calculations. The maximum duration of excluded data is 2 hours in any 24-hour period, unless some other duration is specified by permit.

    b. *Limiting Data Exclusion.* If the compliance calculation using all valid CEMS emission data (as defined in this Appendix) indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

    c. *Event Driven Exclusion.* The underlying event (startup, shutdown, or malfunction) must precede the data exclusion. If there is no underlying event, then no data may be excluded.

    d. *Continuous Exclusion.* Data shall be excluded on a continuous basis per event. Data from discontinuous periods shall not be excluded for the same underlying event.

    e. *Reporting Excluded Data.* These procedures for excluding SIP-based excess emissions from compliance calculations are not necessarily the same procedures used for "excess emissions" as defined by federal rules. Semiannual reports required by this permit shall indicate the duration of data excluded from SIP compliance calculations as well as the number of excess emissions as defined in the applicable federal rules.

15. Acid Rain CEMS: For CEMS that are also subject to the acid rain program, the data substitution and bias adjustment procedures from 40 CFR part 75 shall only be applied to data submitted to the EPA. Compliance with SIP-based emission standards shall be determined using unadjusted data and using the calculation procedures of this Appendix. [Rule 62-4.070(3), F.A.C.]

MONITOR AVAILABILITY

16. Monitor Availability: Monitor availability shall be calculated on a quarterly basis for each emission unit as the number of valid hourly averages obtained by the CEMS, divided by the number of operating hours, times 100%. The monitor availability calculation shall not include periods of time where the monitor was functioning properly, but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit, or relative accuracy audits (RAA). Monitor availability for each CEMS shall be 95% or greater in any calendar quarter. Monitor availability shall be reported in the quarterly excess emissions report. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit. [Rule 62-4.070(3), F.A.C.]

CALCULATING AND REPORTING ANNUAL EMISSIONS

17. CEMS for Calculating Annual Emissions: As defined by this Appendix, all valid data shall be used when calculating annual emissions.

    a. Annual emissions shall include data collected during startup, shutdown, and malfunction periods.

    b. Annual emissions shall include data collected during periods when the emission unit is not operating but emissions are being generated (for example, firing fuel to warm up a process for some period of time prior to the emission unit's "official" startup).

    c. Annual emissions shall not include data from periods of time where the monitor was functioning properly but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit, or RAA. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

    d. Annual emissions shall not include data from periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

    [Rule 62-4.070(3), F.A.C.]

18. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hour block average that begins at the top of each hour. For each hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the permittee shall account for emissions during that hour using site-specific data to generate a reasonable estimate of the 1-hour block average. [Rule 62-4.070(3), F.A.C.]

19. Emissions Calculation: Hourly emissions shall be calculated for each hour as the product of the 1-hour block average and the duration of pollutant emissions during that hour. Annual emissions shall be calculated as the sum of all hourly emissions occurring during the year. [Rule 62-4.070(3), F.A.C.]

20. Acid Rain CEMS: For CEMS that are also subject to the acid rain program, the data substitution and bias adjustment procedures from 40 CFR part 75 shall only be applied to data submitted to the U.S. EPA. Annual emissions shall be determined using unadjusted data and using the calculation procedures of this Appendix. [Rule 62-4.070(3), F.A.C.]

21. Reporting Annual Emissions: The permittee shall use data from each required CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rules 62-210.370(3) and 62-212.300(1)(e), F.A.C. The owner or operator shall follow the procedures in Appendix E (Standard CEMS Requirements) for calculating annual emissions. [Rule 62-4.070(3), F.A.C.]

40 CFR 60, NSPS SUBPART A - GENERAL PROVISIONS

The following emissions units are subject to applicable New Source Performance Standards (NSPS) in 40 CFR 60, which are adopted by reference in Rule 62-204.800(8), F.A.C.

EU No.	Description
023	Limestone and Gypsum Material Handling Activities
024	The CBO Unit is a fluidized bed combustor that will reburn fly ash generated from Units 4 and 5 to produce low-carbon, low-ammonia fly ash material suitable for commercial use. Flue gas exhaust from CBO Unit is directed back into the ductwork of Units 4 and 5 prior to the control equipment.

The affected emission units are subject to the applicable General Provisions in Subpart A of the New Source Performance Standards including: §60.1 (Applicability); §60.2 (Definitions(; §60.3 (Units and Abbreviations); §60.4 (Address); §60.5 (Determination of Construction or Modification); §60.6 (Review of Plans); §60.7 (Notification and Record Keeping); §60.8 (Performance Tests); §60.9 (Availability of Information); §60.10 (State Authority); §60.11 (Compliance with Standards and Maintenance Requirements); §60.12 (Circumvention); §60.13 (Monitoring Requirements); §60.14 (Modification); §60.15 (Reconstruction); §60.16 (Priority List); §60.17 (Incorporations by Reference); §60.18 (General Control Device Requirements); §60.19 (General Notification and Reporting Requirements). The General Provisions are not included in this permit, but can be obtained from the Department upon request.

40 CFR 60, SUBPART Dc - STANDARDS OF PERFORMANCE FOR SMALL INDUSTRIAL-COMMERCIAL-INSITUTIONAL STEAM GENERATING UNITS

The following emissions units are subject to applicable New Source Performance Standards (NSPS) in 40 CFR 60, which are adopted by reference in Rule 62-204.800(8), F.A.C.

EU No.	Description
024	The CBO Unit is a fluidized bed combustor that will reburn fly ash generated from Units 4 and 5 to produce low-carbon, low-ammonia fly ash material suitable for commercial use. Flue gas exhaust from CBO Unit is directed back into the ductwork of Units 4 and 5 prior to the control equipment.

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§ 60.40c Applicability and Delegation of Authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §

60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Not applicable.

(d) Not applicable.

(e) Not applicable.

(f) Not applicable.

(g) Not applicable.

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society of Testing and Materials in ASTM D388-77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (IBR--see Sec. 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (i.e., the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396-78, 89, 90, 92, 96, or 98, "Standard Specification for Fuel Oils" (incorporated by reference -- see § 60.17).

Dry flue gas desulfurization technology means a sulfur dioxide (SO2) control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR Parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835-86, 87, 91, or 97, "Standard Specification for Liquefied Petroleum Gases" (incorporated by reference -- see § 60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO2 emissions (nanograms per joule [ng/J], or pounds per million Btu [lb/million Btu] heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396-78, 89, 90, 92, 96, or 98, "Standard Specification for Fuel Oils" (incorporated by reference -- see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Wet flue gas desulfurization technology means an SO2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter (PM) or SO2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

§ 60.42c Standard for Sulfur Dioxide.

(a) Not applicable.

(b) Not applicable.

(c) Not applicable.

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/million Btu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

{Permitting Note: The permit restricts fuel oil for startup to a maximum sulfur content of 0.5% by weight. Flue gases from the CBO unit are directed back into the ductwork for Units 4 and 5 to meet an SO2 standard of 0.27 lb/MMBtu of heat input. Compliance with this NSPS Subpart Dc requirement is assured by compliance with the permit conditions.}

(e) Not applicable.

(f) Not applicable.

(g) Not applicable.

(h) Not applicable.

(i) The SO_2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

§ 60.43c Standard for Particulate Matter.

(a) Not applicable.

(b) Not applicable.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e) Not applicable.

§ 60.44c Compliance and Performance Test Methods and Procedures for Sulfur Dioxide.

(a) Not applicable.

(b) Not applicable.

(c) Not applicable.

(d) Not applicable.

(e) Not applicable.

(f) Not applicable.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under § 60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under § 60.46c(d)(2).

(h) Not applicable.

(i) Not applicable.

(j) Not applicable.

§ 60.45c Compliance and Performance Test Methods and Procedures for Particulate Matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under Sec. 60.43c shall conduct an initial performance test as required under Sec. 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) and (d) of this section.

(b) Not applicable.

(c) Units that burn only oil containing no more than 0.5 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 230 ng/J (0.54 lb/MMBtu) heat input or less are not required to conduct emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

(d) Not applicable.

§ 60.46c Emission Monitoring for Sulfur Dioxide

(a) Not applicable.

(b) Not applicable.

(c) Not applicable.

(d) Not applicable.

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under § 60.48c(f) (1), (2), or (3), as applicable.

(f) Not applicable.

§ 60.47c Emission Monitoring for Particulate Matter.

(a) The owner or operator of an affected facility combusting coal, oil, gas, or wood that is subject to the opacity standards under Sec. 60.43c shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system, except as specified in paragraphs (c) and (d) of this section.

(b) Not applicable.

(c) Units that burn only oil that contains no more than 0.5 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 230 ng/J (0.54 lb/MMBtu) heat input or less are not required to conduct PM emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

(d) Not applicable.

§ 60.48c Reporting and Recordkeeping Requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) Not applicable.

(3) Not applicable.

(4) Not applicable.

(b) The owner or operator of each affected facility subject to the SO_2 emission limits of § 60.42c, or the PM or opacity limits of § 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B.

(c) The owner or operator of each coal-fired, residual oil-fired, or wood-fired affected facility subject to the opacity limits under § 60.43c(c) shall submit excess emission reports for any excess emissions reports for any excess emissions from the affected facility which occur during the reporting period.

(d) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.43c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2 emission rate (ng/J or lb/million Btu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO_2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_2 or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 (appendix B).

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as

described under paragraph (f)(1), (2), or (3) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier; and

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in § 60.41c.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) Not applicable.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The owner or operator of an affected facility that only burns very low sulfur fuel oil or other liquid or gaseous fuels with potential sulfur dioxide emissions rate of 140 ng/J (0.32 lb/MMBtu) heat input or less shall record and maintain records of the fuels combusted during each calendar month.

(h) Not applicable.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of each reporting period.

40 CFR PART 60, SUBPART OOO - STANDARDS OF PERFORMANCE FOR NONMETALLIC MINERAL PROCESSING PLANTS

The following emissions units are subject to applicable New Source Performance Standards (NSPS) in 40 CFR 60, which are adopted by reference in Rule 62-204.800(8), F.A.C.

EU No.	Description
023	Limestone and Gypsum Material Handling Activities

§ 60.670 Applicability and designation of affected facility.

(a)

(1) Except as provided in paragraphs (a)(2), (b), (c), and (d) of this section, the provisions of this subpart are applicable to the following affected facilities in fixed or portable nonmetallic mineral processing plants: each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station. Also, crushers and grinding mills at hot mix asphalt facilities that reduce the size of nonmetallic minerals embedded in recycled asphalt pavement and subsequent affected facilities up to, but not including, the first storage silo or bin are subject to the provisions of this subpart.

(2) The provisions of this subpart do not apply to the following operations: All facilities located in underground mines; and stand-alone screening operations at plants without crushers or grinding mills.

(b) An affected facility that is subject to the provisions of subpart F or I or that follows in the plant process any facility subject to the provisions of subparts F or I of this part is not subject to the provisions of this subpart.

(c) Facilities at the following plants are not subject to the provisions of this subpart:

(1) Fixed sand and gravel plants and crushed stone plants with capacities, as defined in §60.671, of 23 megagrams per hour (25 tons per hour) or less;

(2) Portable sand and gravel plants and crushed stone plants with capacities, as defined in §60.671, of 136 megagrams per hour (150 tons per hour) or less; and

(3) Common clay plants and pumice plants with capacities, as defined in §60.671, of 9 megagrams per hour (10 tons per hour) or less.

(d)

(1) When an existing facility is replaced by a piece of equipment of equal or smaller size, as defined in §60.671, having the same function as the existing facility, the new facility is exempt from the provisions of §§60.672, 60.674, and 60.675 except as provided for in paragraph (d)(3) of this section.

(2) An owner or operator complying with paragraph (d)(1) of this section shall submit the information required in §60.676(a).

(3) An owner or operator replacing all existing facilities in a production line with new facilities does not qualify for the exemption described in paragraph (d)(1) of this section and must comply with the provisions of §§60.672, 60.674 and 60.675.

(e) An affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after August 31, 1983 is subject to the requirements of this part.

(f) Table 1 of this subpart specifies the provisions of subpart A of this part 60 that apply and those that do not apply to owners and operators of affected facilities subject to this subpart.

Table 1—Applicability of Subpart A to Subpart OOO

Subpart A reference	Applies to Subpart OOO	Comment
60.1, Applicability	Yes	
60.2, Definitions	Yes	
60.3, Units and abbreviations	Yes	
60.4, Address:		
(a)	Yes	
(b)	Yes	
60.5, Determination of construction or modification	Yes	
60.6, Review of plans	Yes	

Subpart A reference	Applies to Subpart OOO	Comment
60.7, Notification and recordkeeping	Yes	Except in (a)(2) report of anticipated date of initial startup is not required (§60.676(h)).
60.8, Performance tests	Yes	Except in (d), after 30 days notice for an initially scheduled performance test, any rescheduled performance test requires 7 days notice, not 30 days (§60.675(g)).
60.9, Availability of information	Yes	
60.10, State authority	Yes	
60.11, Compliance with standards and maintenance requirements	Yes	Except in (b) under certain conditions (§§60.675 (c)(3) and (c)(4)), Method 9 observation may be reduced from 3 hours to 1 hour. Some affected facilities exempted from Method 9 tests (§60.675(h)).
60.12, Circumvention	Yes	
60.13, Monitoring requirements	Yes	
60.14, Modification	Yes	
60.15, Reconstruction	Yes	
60.16, Priority list	Yes	
60.17, Incorporations by reference	Yes	
60.18, General control device	No	Flares will not be used to comply with the emission limits.
60.19, General notification and reporting requirements	Yes	

§ 60.671 Definitions.

All terms used in this subpart, but not specifically defined in this section, shall have the meaning given them in the Act and in subpart A of this part.

Bagging operation means the mechanical process by which bags are filled with nonmetallic minerals.

Belt conveyor means a conveying device that transports material from one location to another by means of an endless belt that is carried on a series of idlers and routed around a pulley at each end.

Bucket elevator means a conveying device of nonmetallic minerals consisting of a head and foot assembly which supports and drives an endless single or double strand chain or belt to which buckets are attached.

Building means any frame structure with a roof.

Capacity means the cumulative rated capacity of all initial crushers that are part of the plant.

Capture system means the equipment (including enclosures, hoods, ducts, fans, dampers, etc.) used to capture and transport particulate matter generated by one or more process operations to a control device.

Control device means the air pollution control equipment used to reduce particulate matter emissions released to the atmosphere from one or more process operations at a nonmetallic mineral processing plant.

Conveying system means a device for transporting materials from one piece of equipment or location to another location within a plant. Conveying systems include but are not limited to the following: Feeders, belt conveyors, bucket elevators and pneumatic systems.

Crusher means a machine used to crush any nonmetallic minerals, and includes, but is not limited to, the following types: jaw, gyratory, cone, roll, rod mill, hammermill, and impactor.

Enclosed truck or railcar loading station means that portion of a nonmetallic mineral processing plant where nonmetallic minerals are loaded by an enclosed conveying system into enclosed trucks or railcars.

Fixed plant means any nonmetallic mineral processing plant at which the processing equipment specified in §60.670(a) is attached by a cable, chain, turnbuckle, bolt or other means (except electrical connections) to any anchor, slab, or structure including bedrock.

Fugitive emission means particulate matter that is not collected by a capture system and is released to the atmosphere at the point of generation.

Grinding mill means a machine used for the wet or dry fine crushing of any nonmetallic mineral. Grinding mills include, but are not limited to, the following types: hammer, roller, rod, pebble and ball, and fluid energy. The grinding mill includes the air conveying system, air separator, or air classifier, where such systems are used.

Initial crusher means any crusher into which nonmetallic minerals can be fed without prior crushing in the plant.

Nonmetallic mineral means any of the following minerals or any mixture of which the majority is any of the following minerals:

(a) Crushed and Broken Stone, including Limestone, Dolomite, Granite, Traprock, Sandstone, Quartz, Quartzite, Marl, Marble, Slate, Shale, Oil Shale, and Shell.

(b) Sand and Gravel.

(c) Clay including Kaolin, Fireclay, Bentonite, Fuller's Earth, Ball Clay, and Common Clay.

(d) Rock Salt.

(e) Gypsum.

(f) Sodium Compounds, including Sodium Carbonate, Sodium Chloride, and Sodium Sulfate.

(g) Pumice.

(h) Gilsonite.

(i) Talc and Pyrophyllite.

(j) Boron, including Borax, Kernite, and Colemanite.

(k) Barite.

(l) Fluorospar.

(m) Feldspar.

(n) Diatomite.

(o) Perlite.

(p) Vermiculite.

(q) Mica.

(r) Kyanite, including Andalusite, Sillimanite, Topaz, and Dumortierite.

Nonmetallic mineral processing plant means any combination of equipment that is used to crush or grind any nonmetallic mineral wherever located, including lime plants, power plants, steel mills, asphalt concrete plants, portland cement plants, or any other facility processing nonmetallic minerals except as provided in §60.670 (b) and (c).

Portable plant means any nonmetallic mineral processing plant that is mounted on any chassis or skids and may be moved by the application of a lifting or pulling force. In addition, there shall be no cable, chain, turnbuckle, bolt or other means (except electrical connections) by which any piece of equipment is attached or clamped to any anchor, slab, or structure, including bedrock that must be removed prior to the application of a lifting or pulling force for the purpose of transporting the unit.

Production line means all affected facilities (crushers, grinding mills, screening operations, bucket elevators, belt conveyors, bagging operations, storage bins, and enclosed truck and railcar loading stations) which are directly connected or are connected together by a conveying system.

Screening operation means a device for separating material according to size by passing undersize material through one or more mesh surfaces (screens) in series, and retaining oversize material on the mesh surfaces (screens).

Size means the rated capacity in tons per hour of a crusher, grinding mill, bucket elevator, bagging operation, or enclosed truck or railcar loading station; the total surface area of the top screen of a screening operation; the width of a conveyor belt; and the rated capacity in tons of a storage bin.

Stack emission means the particulate matter that is released to the atmosphere from a capture system.

Storage bin means a facility for storage (including surge bins) or nonmetallic minerals prior to further processing or loading.

Transfer point means a point in a conveying operation where the nonmetallic mineral is transferred to or from a belt conveyor except where the nonmetallic mineral is being transferred to a stockpile.

Truck dumping means the unloading of nonmetallic minerals from movable vehicles designed to transport nonmetallic minerals from one location to another. Movable vehicles include but are not limited to: trucks, front end loaders, skip hoists, and railcars.

Vent means an opening through which there is mechanically induced air flow for the purpose of exhausting from a building air carrying particulate matter emissions from one or more affected facilities.

Wet mining operation means a mining or dredging operation designed and operated to extract any nonmetallic mineral regulated under this subpart from deposits existing at or below the water table, where the nonmetallic mineral is saturated with water.

Wet screening operation means a screening operation at a nonmetallic mineral processing plant which removes unwanted material or which separates marketable fines from the product by a washing process which is designed and operated at all times such that the product is saturated with water.

§ 60.672 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any transfer point on belt conveyors or from any other affected facility any stack emissions which:

  (1) Contain particulate matter in excess of 0.05 g/dscm (0.022 gr/dscf); and

  (2) Exhibit greater than 7 percent opacity, unless the stack emissions are discharged from an affected facility using a wet scrubbing control device. Facilities using a wet scrubber must comply with the reporting provisions of §60.676 (c), (d), and (e).

(b) On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under §60.11 of this part, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any transfer point on belt conveyors or from any other affected facility any fugitive emissions which exhibit greater than 10 percent opacity, except as provided in paragraphs (c), (d), and (e) of this section.

(c) On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under §60.11 of this part, no owner or operator shall cause to be discharged into the atmosphere from any crusher, at which a capture system is not used, fugitive emissions which exhibit greater than 15 percent opacity.

(d) Truck dumping of nonmetallic minerals into any screening operation, feed hopper, or crusher is exempt from the requirements of this section.

(e) If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in paragraphs (a), (b) and (c) of this section, or the building enclosing the affected facility or facilities must comply with the following emission limits:

(1) No owner or operator shall cause to be discharged into the atmosphere from any building enclosing any transfer point on a conveyor belt or any other affected facility any visible fugitive emissions except emissions from a vent as defined in §60.671.

(2) No owner or operator shall cause to be discharged into the atmosphere from any vent of any building enclosing any transfer point on a conveyor belt or any other affected facility emissions which exceed the stack emissions limits in paragraph (a) of this section.

(f) On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under §60.11 of this part, no owner or operator shall cause to be discharged into the atmosphere from any baghouse that controls emissions from only an individual, enclosed storage bin, stack emissions which exhibit greater than 7 percent opacity.

(g) Owners or operators of multiple storage bins with combined stack emissions shall comply with the emission limits in paragraph (a)(1) and (a)(2) of this section.

(h) On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup, no owner or operator shall cause to be discharged into the atmosphere any visible emissions from:

(1) Wet screening operations and subsequent screening operations, bucket elevators, and belt conveyors that process saturated material in the production line up to the next crusher, grinding mill or storage bin.

(2) Screening operations, bucket elevators, and belt conveyors in the production line downstream of wet mining operations, where such screening operations, bucket elevators, and belt conveyors process saturated materials up to the first crusher, grinding mill, or storage bin in the production line.

§ 60.673 Reconstruction.

(a) The cost of replacement of ore-contact surfaces on processing equipment shall not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital cost that would be required to construct a comparable new facility" under §60.15. Ore-contact surfaces are crushing surfaces; screen meshes, bars, and plates; conveyor belts; and elevator buckets.

(b) Under §60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components (except components specified in paragraph (a) of this section) which are or will be replaced pursuant to all continuous programs of component replacement commenced within any 2-year period following August 31, 1983.

§ 60.674 Monitoring of operations.

The owner or operator of any affected facility subject to the provisions of this subpart which uses a wet scrubber to control emissions shall install, calibrate, maintain and operate the following monitoring devices:

(a) A device for the continuous measurement of the pressure loss of the gas stream through the scrubber. The monitoring device must be certified by the manufacturer to be accurate within ±250 pascals ±1 inch water gauge pressure and must be calibrated on an annual basis in accordance with manufacturer's instructions.

(b) A device for the continuous measurement of the scrubbing liquid flow rate to the wet scrubber. The monitoring device must be certified by the manufacturer to be accurate within ±5 percent of design scrubbing liquid flow rate and must be calibrated on an annual basis in accordance with manufacturer's instructions.

§ 60.675 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the particulate matter standards in §60.672(a) as follows:

(1) Method 5 or Method 17 shall be used to determine the particulate matter concentration. The sample volume shall be at least 1.70 dscm (60 dscf). For Method 5, if the gas stream being sampled is at ambient temperature, the sampling probe and filter may be operated without heaters. If the gas stream is above ambient temperature, the sampling probe and filter may be operated at a temperature high enough, but no higher than 121 °C (250 °F), to prevent water condensation on the filter.

(2) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(c)

(1) In determining compliance with the particulate matter standards in §60.672 (b) and (c), the owner or operator shall use Method 9 and the procedures in §60.11, with the following additions:

(i) The minimum distance between the observer and the emission source shall be 4.57 meters (15 feet).

(ii) The observer shall, when possible, select a position that minimizes interference from other fugitive emission sources (e.g., road dust). The required observer position relative to the sun (Method 9, Section 2.1) must be followed.

(iii) For affected facilities using wet dust suppression for particulate matter control, a visible mist is sometimes generated by the spray. The water mist must not be confused with particulate matter emissions and is not to be considered a visible emission. When a water mist of this nature is present, the observation of emissions is to be made at a point in the plume where the mist is no longer visible.

(2) In determining compliance with the opacity of stack emissions from any baghouse that controls emissions only from an individual enclosed storage bin under §60.672(f) of this subpart, using Method 9, the duration of the Method 9 observations shall be 1 hour (ten 6-minute averages).

(3) When determining compliance with the fugitive emissions standard for any affected facility described under §60.672(b) of this subpart, the duration of the Method 9 observations may be reduced from 3 hours (thirty 6-minute averages) to 1 hour (ten 6-minute averages) only if the following conditions apply:

(i) There are no individual readings greater than 10 percent opacity; and

(ii) There are no more than 3 readings of 10 percent for the 1-hour period.

(4) When determining compliance with the fugitive emissions standard for any crusher at which a capture system is not used as described under §60.672(c) of this subpart, the duration of the Method 9 observations may be reduced from 3 hours (thirty 6-minute averages) to 1 hour (ten 6-minute averages) only if the following conditions apply:

(i) There are no individual readings greater than 15 percent opacity; and

(ii) There are no more than 3 readings of 15 percent for the 1-hour period.

(d) In determining compliance with §60.672(e), the owner or operator shall use Method 22 to determine fugitive emissions. The performance test shall be conducted while all affected facilities inside the building are operating. The performance test for each building shall be at least 75 minutes in duration, with each side of the building and the roof being observed for at least 15 minutes.

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For the method and procedure of paragraph (c) of this section, if emissions from two or more facilities continuously interfere so that the opacity of fugitive emissions from an individual affected facility cannot be read, either of the following procedures may be used:

(i) Use for the combined emission stream the highest fugitive opacity standard applicable to any of the individual affected facilities contributing to the emissions stream.

(ii) Separate the emissions so that the opacity of emissions from each affected facility can be read.

(f) To comply with §60.676(d), the owner or operator shall record the measurements as required in §60.676(c) using the monitoring devices in §60.674 (a) and (b) during each particulate matter run and shall determine the averages.

(g) If, after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting any rescheduled performance test required in this section, the owner or operator of an affected facility shall submit a notice to the Administrator at least 7 days prior to any rescheduled performance test.

(h) Initial Method 9 performance tests under §60.11 of this part and §60.675 of this subpart are not required for:

(1) Wet screening operations and subsequent screening operations, bucket elevators, and belt conveyors that process saturated material in the production line up to, but not including the next crusher, grinding mill or storage bin.

(2) Screening operations, bucket elevators, and belt conveyors in the production line downstream of wet mining operations, that process saturated materials up to the first crusher, grinding mill, or storage bin in the production line.

§ 60.676 Reporting and recordkeeping.

(a) Each owner or operator seeking to comply with §60.670(d) shall submit to the Administrator the following information about the existing facility being replaced and the replacement piece of equipment.

(1) For a crusher, grinding mill, bucket elevator, bagging operation, or enclosed truck or railcar loading station:

(i) The rated capacity in megagrams or tons per hour of the existing facility being replaced and

(ii) The rated capacity in tons per hour of the replacement equipment.

(2) For a screening operation:

(i) The total surface area of the top screen of the existing screening operation being replaced and

(ii) The total surface area of the top screen of the replacement screening operation.

(3) For a conveyor belt:

(i) The width of the existing belt being replaced and

(ii) The width of the replacement conveyor belt.

(4) For a storage bin:

(i) The rated capacity in megagrams or tons of the existing storage bin being replaced and

(ii) The rated capacity in megagrams or tons of replacement storage bins.

(b) [Reserved]

(c) During the initial performance test of a wet scrubber, and daily thereafter, the owner or operator shall record the measurements of both the change in pressure of the gas stream across the scrubber and the scrubbing liquid flow rate.

(d) After the initial performance test of a wet scrubber, the owner or operator shall submit semiannual reports to the Administrator of occurrences when the measurements of the scrubber pressure loss (or gain) and liquid flow rate differ by more than ±30 percent from the averaged determined during the most recent performance test.

(e) The reports required under paragraph (d) shall be postmarked within 30 days following end of the second and fourth calendar quarters.

(f) The owner or operator of any affected facility shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in §60.672 of this subpart, including reports of opacity observations made using Method 9 to demonstrate compliance with §60.672(b), (c), and (f), and reports of observations using Method 22 to demonstrate compliance with §60.672(e).

(g) The owner or operator of any screening operation, bucket elevator, or belt conveyor that processes saturated material and is subject to §60.672(h) and subsequently processes unsaturated materials, shall submit a report of this change within 30 days following such change. This screening operation, bucket elevator, or belt conveyor is then subject to the 10 percent opacity limit in §60.672(b) and the emission test requirements of §60.11 and this subpart. Likewise a screening operation, bucket elevator, or belt conveyor that processes unsaturated material but subsequently processes saturated material shall submit a report of this change within 30 days following such change. This screening operation, bucket elevator, or belt conveyor is then subject to the no visible emission limit in §60.672(h).

(h) The subpart A requirement under §60.7(a)(2) for notification of the anticipated date of initial startup of an affected facility shall be waived for owners or operators of affected facilities regulated under this subpart.

(i) A notification of the actual date of initial startup of each affected facility shall be submitted to the Administrator.

  (1) For a combination of affected facilities in a production line that begin actual initial startup on the same day, a single notification of startup may be submitted by the owner or operator to the Administrator. The notification shall be postmarked within 15 days after such date and shall include a description of each affected facility, equipment manufacturer, and serial number of the equipment, if available.

  (2) For portable aggregate processing plants, the notification of the actual date of initial startup shall include both the home office and the current address or location of the portable plant.

(j) The requirements of this section remain in force until and unless the Agency, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such States. In that event, affected facilities within the State will be relieved of the obligation to comply with the reporting requirements of this section, provided that they comply with requirements established by the State.

Livingston, Sylvia

From: Livingston, Sylvia
Sent: Friday, September 03, 2010 4:30 PM
To: 'larry.hatcher@pgnmail.com'
Cc: 'dave.meyer@pgnmail.com'; 'sosbourn@golder.com'; Halpin, Mike; Zhang-Torres; 'forney.kathleen@epa.gov'; 'abrams.heather@epamail.epa.gov'; 'oquendo.ana@epa.gov'; 'dee_morse@nps.gov'; Gibson, Victoria; Koerner, Jeff; Walker, Elizabeth (AIR)
Subject: CRYSTAL RIVER POWER PLANT; 0170004-023-AC/ PSD-FL-383C
Attachments: 0170004.023.AC.D_pdf.zip

Dear Sir/ Madam:

Attached is the official **Notice of Intent to Issue** for the project referenced below. **Open the attached files** to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Owner/Company Name: FLORIDA POWER CORPORATION D/B/A PROGRESS
Facility Name: CRYSTAL RIVER POWER PLANT
Project Number: 0170004-023-AC/ PSD-FL-383C
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: CITRUS
Processor: Jeff Koerner

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/emission/apds/default.asp.

Permit project documents are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-9506
sylvia.livingston@dep.state.fl.us

Note: The attached document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: <http://www.adobe.com/products/acrobat/readstep.html> .

Tracking:

Livingston, Sylvia

From: Osbourn, Scott [Scott_Osbourn@golder.com]
To: Livingston, Sylvia
Sent: Friday, September 03, 2010 5:20 PM
Subject: Read: CRYSTAL RIVER POWER PLANT; 0170004-023-AC/ PSD-FL-383C

Your message was read on Friday, September 03, 2010 5:20:10 PM (GMT-05:00) Eastern Time (US & Canada).

Livingston, Sylvia

From: Livingston, Sylvia
Sent: Tuesday, September 14, 2010 4:35 PM
To: 'larry.hatcher@pgnmail.com'
Subject: FW: CRYSTAL RIVER POWER PLANT; 0170004-023-AC/ PSD-FL-383C
Attachments: 0170004.023.AC.D_pdf.zip

Dear Larry Hatcher:

We have not received confirmation that you were able to access the documents attached to this September 3rd e-mail. Please confirm receipt by opening the attachment and sending a reply to me.

The Division of Air Resource Management is sending electronic versions of these documents rather than sending them Return Receipt Requested via the US Postal service. Your "receipt confirmation" reply serves the same purpose as tracking the receipt of the signed "Return Receipt" card from the US Postal Service. Please let me know if you have any questions.

Sylvia Livingston
Division of Air Resource Management (DARM)
Department of Environmental Protection
850/488-0114
sylvia.livingston@dep.state.fl.us

From: Livingston, Sylvia
Sent: Friday, September 03, 2010 4:30 PM
To: 'larry.hatcher@pgnmail.com'
Cc: 'dave.meyer@pgnmail.com'; 'sosbourn@golder.com'; Halpin, Mike; Zhang-Torres; 'forney.kathleen@epa.gov'; 'abrams.heather@epamail.epa.gov'; 'oquendo.ana@epa.gov'; 'dee_morse@nps.gov'; Gibson, Victoria; Koerner, Jeff; Walker, Elizabeth (AIR)
Subject: CRYSTAL RIVER POWER PLANT; 0170004-023-AC/ PSD-FL-383C

Dear Sir/ Madam:

Attached is the official **Notice of Intent to Issue** for the project referenced below. **Open the attached files** to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Owner/Company Name: FLORIDA POWER CORPORATION D/B/A PROGRESS
Facility Name: CRYSTAL RIVER POWER PLANT
Project Number: 0170004-023-AC/ PSD-FL-383C
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: CITRUS
Processor: Jeff Koerner

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/emission/apds/default.asp.

Permit project documents are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-9506
sylvia.livingston@dep.state.fl.us

Note: The attached document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: <http://www.adobe.com/products/acrobat/readstep.html> .

Livingston, Sylvia

From: Hatcher, Larry [Larry.Hatcher@pgnmail.com]
Sent: Wednesday, September 15, 2010 6:45 AM
To: Livingston, Sylvia
Subject: RE: CRYSTAL RIVER POWER PLANT; 0170004-023-AC/ PSD-FL-383C

I received the document attached.

Larry

-----Original Message-----
From: Livingston, Sylvia [mailto:Sylvia.Livingston@dep.state.fl.us]
Sent: Tuesday, September 14, 2010 4:26 PM
To: 'larry.hatcher@pgnmail.com'
Subject: FW: CRYSTAL RIVER POWER PLANT; 0170004-023-AC/ PSD-FL-383C

A .ZIP file attached to this email was removed. This file type is prohibited because of security concerns. If the attachment was a legitimate file that you were expecting and from a trusted source, you should arrange an alternate delivery method with the sender.

Provided the files are not among the blocked types listed below and they total less than 20MB, the sender can email you the unzipped file(s). Alternatively you may consider asking the sender to upload the file(s) to our FTP site where you will then be able to retrieve them. For assistance using the FTP site, call the Technology Service Desk at VoiceNet 230-5111 (toll free 1-866-230-5111). NGG employees should contact the NGG help desk for assistance at VoiceNet 770-2050.

The following types of attachments are blocked from transit via email:
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*.JS *.JSE *.JSF *.NWS *.OVL *.PIF *.RAR *.SCR *.SHS *.SYS *.VBE *.VBS *.WMF *.WSF *.WSH
*.ZIP

Some parts of this message were removed because they violated your mail server's policies.

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