Friday, Barbara 5/18/07

To: bernie.cumbie@pgnmail.com; Meyer, Dave; john.hunter@pgnmail.com; sosbourn@golder.com; Zhang-Torres; Halpin, Mike; 'Little.James@epamail.epa.gov'; 'Forney.Kathleen@epamail.epa.gov'; dee_morse@nps.gov

Cc: Adams, Patty; Koerner, Jeff

Subject: FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

Attachments: Signed Documents for Permit #0170004-016-AC-FINAL.pdf; PSD-FL-383 - Appendix - 0170004-016-AC-FINAL.pdf; PSD-FL-383 - Final Determination - 0170004-016-AC-Final.pdf; PSD-FL-383 - Final Notice - 0170004-016-FINAL.pdf; PSD-FL-383 - Final Permit - 0170004-016-AC-FINAL.pdf

Dear Sir/Madam:

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Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From: Forney.Kathleen@epamail.epa.gov
Sent: Friday, May 18, 2007 1:28 PM
To: Friday, Barbara
Subject: Re: FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

Attachments: Signed Documents for Permit #0170004-016-AC-FINAL.pdf; PSD-FL-383 - Appendix - 0170004-016-AC-FINAL.pdf; PSD-FL-383 - Final Determination - 0170004-016-AC-Final.pdf; PSD-FL-383 - Final Notice - 0170004-016-FINAL.pdf; PSD-FL-383 - Final Permit - 0170004-016-AC-FINAL.pdf

Signed Documents for Permit #0... | PSD-FL-383 - \ppendix - 017000.. | PSD-FL-383 - Final Determinati... | PSD-FL-383 - Final Notice - 01... | PSD-FL-383 - Final Permit - 01...

Thanks.

Katy R. Forney
Air Permits Section
EPA - Region 4
61 Forsyth St., SW
Atlanta, GA 30024

Phone: 404-562-9130
Fax: 404-562-9019

"Friday, Barbara" <Barbara.Friday@dep.state.fl.us>

05/18/2007 01:25 PM

To
<bernie.cumbie@pgnmail.com>, "Meyer, Dave" <Dave.Meyer@pgnmail.com>, <john.hunter@pgnmail.com>, <sosbourn@golder.com>, "Zhang-Torres" <Cindy.Zhang-Torres@dep.state.fl.us>, "Halpin, Mike" <Mike.Halpin@dep.state.fl.us>, James Little/R4/USEPA/US@EPA, Kathleen Forney/R4/USEPA/US@EPA, <dee_morse@nps.gov>

cc
"Adams, Patty" <Patty.Adams@dep.state.fl.us>, "Koerner, Jeff" <Jeff.Koerner@dep.state.fl.us>

Subject
FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

Dear Sir/Madam:

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DEP, Bureau of Air Regulation
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Friday, Barbara

From: Cumbie, Bernie M. [Bernie.Cumbie@pgnmail.com]
Sent: Friday, May 18, 2007 1:29 PM
To: Friday, Barbara
Subject: RE: FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

-----Original Message-----
From: Friday, Barbara [mailto:Barbara.Friday@dep.state.fl.us]
Sent: Friday, May 18, 2007 1:25 PM
To: Cumbie, Bernie M.; Meyer, Dave; Hunter, John J (Jamie); sosbourn@golder.com; Zhang-Torres; Halpin, Mike; Little.James@epamail.epa.gov; Forney.Kathleen@epamail.epa.gov; dee_morse@nps.gov
Cc: Adams, Patty; Koerner, Jeff
Subject: FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

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Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From: Halpin, Mike
To: Friday, Barbara
Sent: Friday, May 18, 2007 1:32 PM
Subject: Read: FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

Your message

To:	'bernie.cumbie@pgnmail.com'; 'Meyer, Dave'; 'john.hunter@pgnmail.com'; 'sosbourn@golder.com'; Zhang-Torres; Halpin, Mike; 'Little.James@epamail.epa.gov'; 'Forney.Kathleen@epamail.epa.gov'; 'dee_morse@nps.gov'
Cc:	Adams, Patty; Koerner, Jeff
Subject:	FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant
Sent:	5/18/2007 1:25 PM

was read on 5/18/2007 1:32 PM.

Friday, Barbara

From: Hunter, John J (Jamie) [John.Hunter@pgnmail.com]
To: Friday, Barbara
Sent: Friday, May 18, 2007 1:43 PM
Subject: Read: FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

Your message

To: John.Hunter@pgnmail.com
Subject:

was read on 5/18/2007 1:43 PM.

Friday, Barbara

From: Hunter, John J (Jamie) [John.Hunter@pgnmail.com]

Sent: Friday, May 18, 2007 1:46 PM

To: Friday, Barbara

Subject: RE: FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

Received...

Thanks.

-----Original Message-----
From: Friday, Barbara [mailto:Barbara.Friday@dep.state.fl.us]
Sent: Friday, May 18, 2007 1:25 PM
To: Cumbie, Bernie M.; Meyer, Dave; Hunter, John J (Jamie); sosbourn@golder.com; Zhang-Torres; Halpin, Mike; Little.James@epamail.epa.gov; Forney.Kathleen@epamail.epa.gov; dee_morse@nps.gov
Cc: Adams, Patty; Koerner, Jeff
Subject: FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

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Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From: Meyer, Dave [Dave.Meyer@pgnmail.com]
To: Friday, Barbara
Sent: Friday, May 18, 2007 2:04 PM
Subject: Read: FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

Your message

To: Dave.Meyer@pgnmail.com
Subject:

was read on 5/18/2007 2:04 PM.

Friday, Barbara

From: Osbourn, Scott [Scott_Osbourn@golder.com]
To: undisclosed-recipients
Sent: Friday, May 18, 2007 2:39 PM
Subject: Read: FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

Your message

To: Scott_Osbourn@golder.com
Subject:

was read on 5/18/2007 2:39 PM.

Friday, Barbara

From: System Administrator
To: Halpin, Mike
Sent: Friday, May 18, 2007 1:25 PM
Subject: Delivered:FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

Your message

To: 'bernie.cumbie@pgnmail.com'; 'Meyer, Dave'; 'john.hunter@pgnmail.com'; 'sosbourn@golder.com'; Zhang-Torres; Halpin, Mike; 'Little.James@epamail.epa.gov'; 'Forney.Kathleen@epamail.epa.gov'; 'dee_morse@nps.gov'
Cc: Adams, Patty; Koerner, Jeff
Subject: FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant
Sent: 5/18/2007 1:25 PM

was delivered to the following recipient(s):

Halpin, Mike on 5/18/2007 1:25 PM

Friday, Barbara

From: System Administrator
To: Zhang-Torres; Adams, Patty; Koerner, Jeff
Sent: Friday, May 18, 2007 1:25 PM
Subject: Delivered:FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

Your message

To: 'bernie.cumbie@pgnmail.com'; 'Meyer, Dave'; 'john.hunter@pgnmail.com'; 'sosbourn@golder.com'; Zhang-Torres; Halpin, Mike; 'Little.James@epamail.epa.gov'; 'Forney.Kathleen@epamail.epa.gov'; 'dee_morse@nps.gov'
Cc: Adams, Patty; Koerner, Jeff
Subject: FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant
Sent: 5/18/2007 1:25 PM

was delivered to the following recipient(s):

Zhang-Torres on 5/18/2007 1:25 PM
Adams, Patty on 5/18/2007 1:25 PM
Koerner, Jeff on 5/18/2007 1:25 PM

Friday, Barbara

From: Exchange Administrator
Sent: Friday, May 18, 2007 1:26 PM
To: Friday, Barbara
Subject: Delivery Status Notification (Relay)

Attachments: ATT411807.txt; FINAL Air Permit No. PSD-FL-383, Project No.: 0170004-016-AC - Progress Energy Florida, Inc. - Crystal River Power Plant

ATT411807.txt (284 B)

FINAL Air Permit No. PSD-FL-38...

This is an automatically generated Delivery Status Notification.

Your message has been successfully relayed to the following recipients, but the requested delivery status notifications may not be generated by the destination.

dee_morse@nps.gov

Friday, Barbara

From: Mail Delivery System [MAILER-DAEMON@mseive01.rtp.epa.gov]
Sent: Friday, May 18, 2007 1:25 PM
To: Friday, Barbara
Subject: Successful Mail Delivery Report

Attachments: Delivery report; Message Headers

Delivery report.txt (723 B)   Message Headers.txt (2 KB)

This is the mail system at host mseive01.rtp.epa.gov.

Your message was successfully delivered to the destination(s) listed below. If the message was delivered to mailbox you will receive no further notifications. Otherwise you may still receive notifications of mail delivery errors from other systems.

The mail system

<Forney.Kathleen@epamail.epa.gov>: delivery via 127.0.0.1[127.0.0.1]:10025: 250
OK, sent 464DE17E_22451_34114_3

<Little.James@epamail.epa.gov>: delivery via 127.0.0.1[127.0.0.1]:10025: 250
OK, sent 464DE17E_22451_34114_3

Friday, Barbara

From: Mail Delivery System [MAILER-DAEMON@sophos.golder.com]
Sent: Friday, May 18, 2007 1:25 PM
To: Friday, Barbara
Subject: Successful Mail Delivery Report

Attachments: Delivery report; Message Headers

Delivery report.txt (460 B) Message Headers.txt (2 KB)

This is the mail system at host sophos.golder.com.

Your message was successfully delivered to the destination(s) listed below. If the message was delivered to mailbox you will receive no further notifications. Otherwise you may still receive notifications of mail delivery errors from other systems.

The mail system

<sosbourn@golder.com>: delivery via 127.0.0.1[127.0.0.1]:10025: 250 OK, sent 464DE180_26820_31_2

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

Authorized Representative:
Mr. Bernie Cumbie, Plant Manager

Air Permit No. PSD-FL-383
Project No. 0170004-016-AC
Facility ID No. 0170004
Crystal River Power Plant
Units 4 and 5, Pollution Controls

Enclosed is final Permit No. PSD-FL-383 (Project No. 0170004-016-AC), which authorizes the installation of air pollution control equipment on existing Units 4 and 5 at the Crystal River Power Plant located in Citrus County, north of Crystal River and west of U.S. Highway 19. As noted in the attached Final Determination, only minor changes and clarifications were made. This permit is issued pursuant to Chapter 403, Florida Statutes.

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.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit and the Final Permit were sent by electronic mail (received receipt requested) to the persons listed below.

Mr. Bernie Cumbie, Progress Energy Florida, Inc. (Bernie.Cumbie@pgnmail.com)
Mr. Dave Meyer, Progress Energy Florida, Inc. (Dave.Meyer@pgnmail.com)
Mr. John (Jamie) Hunter, Progress Energy Florida, Inc. (John.Hunter@pgnmail.com)
Mr. Scott Osbourn, Golder Associates Inc. (SOsbourn@golder.com)
Ms. Cindy Zhang-Torres, SWD Office (Cindy.Zhang-Torres@dep.state.fl.us)
Mr. Mike Halpin, Siting Office (Halpin_M@dep.state.fl.us)
Mr. James Little, EPA Region 4 (Little.James@epa.gov)
Ms. Kathleen Forney, EPA Region 4 (Forney.Kathleen@epa.gov)
Mr. Dee Morse, National Park Service (Dee_Morse@nps.gov)

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Mary L Harvey (Clerk) 5/18/07 (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

PERMITTEE:

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

Authorized Representative:
Mr. Bernie Cumbie, Plant Manager

Air Permit No. PSD-FL-383
Project No. 0170004-016-AC
Facility ID No. 0170004
Crystal River Power Plant
Units 4 and 5, Pollution Controls Project
Permit Expires: November 1, 2011

PLANT 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.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.), and Part 60 in Title 40 of the Code of Federal Regulations (CFR). Specifically, this permit is issued in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality. The permittee is authorized to install the proposed equipment and perform the work in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department). This air construction permit supplements all other valid air construction and operation permits.

CONTENTS

Executed in Tallahassee, Florida

Trina L Vielhauer for   5/18/07

Joseph Kahn, Director
Division of Air Resource Management

Effective Date

Memorandum

Florida Department of Environmental Protection

TO:	Joseph Kahn, Division of Air Resource Management
THROUGH:	Trina Vielhauer, Bureau of Air Regulation
FROM:	Jeff Koerner, Air Permitting North JK
DATE:	May 17, 2007
SUBJECT:	Air Permit No. PSD-FL-383, Project No. 0170004-016-AC Progress Energy Florida, Inc., Crystal River Power Plant Units 4 and 5, Pollution Controls Project

The final permit for this project is attached for your approval and signature, which authorizes the installation of air pollution control equipment on existing Units 4 and 5 at the Crystal River Power Plant located in Citrus County, north of Crystal River and west of U.S. Highway 19. To provide full flexibility in implementing the federal cap and trade program for NO_X and SO_2 under CAIR, the applicant proposes to install new low-NO_X burners, new SCR systems, new FGD systems, and new stacks for the existing coal-fired Units 4 and 5. In conjunction with the proposed new equipment, the applicant requests the flexibility to fire additional fuel blends (sub-bituminous coal and petroleum coke). The applicant also proposes to install a new carbon burn-out 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. Finally, the applicant requests authorization for a trial period to evaluate a new fuel additive intended to reduce slagging and improve emissions performance. The project is subject to PSD preconstruction review for CO, PM/PM_{10}, SAM, and VOC emissions.

I recommend your approval of the attached Final Permit for this project.

Attachments

PERMITTEE

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

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation, Air Permitting North Program
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400

PROJECT

Air Permit No. 0170004-016-AC (PSD-FL-383)
Crystal River Power Plant, Pollution Controls Project

The existing Crystal River Power Plant is located in the Crystal River Energy Complex in Citrus County, north of Crystal River and west of U.S. Highway 19. To provide full flexibility in implementing the federal cap and trade program for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) under the Clean Air Interstate Rule, the applicant proposes to install new burners, new selective catalytic reduction systems, new flue gas desulfurization (FGD) systems, and new stacks for the existing coal-fired Units 4 and 5. In conjunction with the proposed new control equipment, the applicant requests the flexibility to fire additional fuel blends (sub-bituminous coal and petroleum coke) and recognition of the true maximum heat input rates for Units 4 and 5. The applicant also proposes to install a new carbon burn-out 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. Finally, the applicant requests authorization for a trial period to evaluate a new fuel additive intended to reduce slagging and improve emissions performance.

NOTICE AND PUBLICATION

The Department distributed an Intent to Issue Permit package on March 19, 2007. The applicant published the Public Notice of Intent to Issue in the Citrus County Chronicle on April 11, 2007. The Department received the proof of publication on April 17, 2007. The Department granted an extension of time to file a petition for an administrative hearing on April 17, 2007. The extension expired on May 16, 2007.

COMMENTS

No comments on the Draft Permit were received from the EPA Region 4, the National Park Service or the Department's Southwest District Office.

Public

On April 23, 2007, we received a letter from Mr. Gordon E. Clark. Mr. Clark expressed an interest in the air permit project because he believes the plant is polluting the air around his house. Mr. Clark commented that there are small black particles in the air and on the exterior vinyl siding of his house. As described above, the primary purpose of the project is to install air pollution control equipment. The comments are acknowledged and the letter was referred to the Department's Southwest District Office on April 25, 2007 for follow up. The District office has contacted Mr. Clark and plans to meet the week of May 21st.

Permittee

The permittee, Progress Energy Florida (PEF), submitted the following comments after which the Department's response is provided. Unless otherwise specified, the referenced permit conditions are in Subsection A of the draft permit.

1. PEF has recently relocated their corporate offices. The correct address is: Progress Energy, Florida Inc., 299 First Avenue North, CN-77, St. Petersburg, Florida 33701.

   Response: The address was updated.

2. In the existing facility description on page 2, it should be clarified that there are two sets of mechanical draft cooling towers: one set of "helper" cooling towers and a second set of "modular" cooling towers.

Response: The existing facility description was updated.

3. In the existing facility description on page 2, it should be clarified that the nuclear unit and associated facilities are permitted under the *same* Title V permit as the coal units.

   Response: The existing facility description was updated.

4. In Condition 1a, clarify that Permit No. 0170004-013-AC for the SCR system is only "void and replaced by this permit" once Permit No. 0170004-016-AC is issued final.

   Response: The concern is acknowledged, but no change is necessary. The terms and conditions of an air construction permit are not effective until issued as a final action.

5. In Condition 2, add a qualifying statement indicating that "the information in this section is based on the preliminary design and the final design may change."

   Response: The following statement was added after the description of the proposed work, "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."

6. In Condition 2c, remove limestone injection feed rate, the percent solids and specific gravity, as these are *preliminary* design estimates. Further, as monitoring of these parameters is not necessary to demonstrate compliance (i.e., the SO_2 CEMS will be used), PEF does not believe it is appropriate to have these design values listed as permit conditions.

   Response: As previously mentioned, the condition was revised to clarify that the information is based on the preliminary design. The Department agrees that compliance with the SO_2 standard will be demonstrated based on CEMS data. However, the parametric data provides additional insight on overall operation of the control equipment and can serve to verify effective control measures should the CEMS be unavailable. No additional change was made.

7. In Condition 2d, revise the last sentence to indicate that, if COMS are to be installed (comments on this issue to follow), the system will be installed in the ductwork prior to the FGD, not on the stack.

   Response: Condition 2d identifies the new stack configuration. Due to the wet stack conditions caused by the FGD system, moisture interference precludes installation of the COMS on the new stack. Therefore, COMS were removed from this condition. The issue is discussed further in Comments #13 and #15.

8. In Condition 3a, the SAM reduction of 85% is identified as a *design* figure. PEF requests that this be removed, as compliance will be determined by meeting the specified emission limit for SAM, not by determination of a required percent reduction.

   Response: The condition was clarified to state, "The preliminary design is for an 85% SAM reduction."

9. In Condition 3b, PEF requests removal of the reference to the ESP post-modification collection efficiency of 99.9%; it is inconsistent with PEF's most recent response to the Department's request for additional information. In addition, the level of detail describing the precipitator work scope is far too specific given detailed engineering has not commenced and changes are inevitable as the entire flue gas control system is optimized to meet permit limits. The permit can and should state the work is expected to improve ESP performance. Further, PEF commits that the total flue gas control system will allow the units to meet the particulate permit limit at the stack. PEF's proposed language revision is included in Attachment 1 to this letter.

   Response: PEF originally provided information that the ESP improvements would increase the calculated collection efficiency to approximately 99.91%. Subsequent information indicated the control efficiency would be 99.54% based on an uncontrolled rate of 6.52 lb/MMBtu and a controlled rate of 0.030 lb/MMBtu. Identifying the proposed work and control efficiency was not intended to be a requirement, but to be descriptive and reflect the capabilities of the ESP. Therefore, the first two sentences of this condition were revised to, "The permittee is authorized ~~required~~ to modify the existing ESPs to achieve the new PM/PM_{10} emissions standards. Some of this work may include the following~~. The primary work includes~~: ..." The last sentence was revised to, "*{Permitting Note: The modifications ~~will~~ are intended to improve the estimated collection efficiency to more than 99.59%.*"

10. In Condition 5a, PEF requests an *annual* averaging time, rather than a 30-day rolling average, for the 6,800 MMBtu/hour heat input limit. PEF based the air quality modeling and other impacts analyses on the worst-case heat input rating of 7,200 MMBtu/hour. If the Department is going to propose a lower heat input limit, such as 6,800 MMBtu/hour, there is no justification for an averaging time more stringent than an annual basis.

    Response: As part of the application, PEF requested that permit identify the true maximum heat input rate so that the current Title V permitting note could be properly revised. In support of the request, PEF provided actual data showing the maximum 1-hour and 24-hour heat input rates for Units 4 and 5. The data showed individual 1-hour averages just above 7200 MMBtu/hour. To provide an operational margin, the requested maximum 7200 MMBtu/hour heat input rate was established as a 24-hour average. In a similar manner, the data showed the individual maximum 24-hour averages just above the requested secondary maximum heat input rate of 6800 MMBtu/hour with the worst case being less than 4% higher. To provide a reasonable operational margin, the requested maximum 6800 MMBtu/hour heat input rate was established as a 30-day rolling average, which is the longest averaging period that stills reflects equipment capacity and capabilities. No change was made.

11. In Condition 8b, PEF requests that the PM/PM_{10} emission rate be specified as 0.03 lb/MMBtu, rather than 0.03$\underline{0}$ lb/MMBtu.

    Response: The PM/PM_{10} standard is a BACT limit and the number of significant digits was intentional. No change was made.

12. In Condition 8c, PEF believes that, based on project-specific issues, the requested SAM limit of 0.012 lb/MMBtu is still appropriate and representative of BACT. There are very few retrofit boiler control systems documented in the EPA BACT/LAER Clearinghouse, and none were identified which deal with a BACT SAM limit for existing units utilizing an alkali injection system. However, PEF was able to identify a Constellation facility, referred to as the Brandon Shores Generating Station, which recently applied for an air construction permit for a retrofit project similar in many respects to the Crystal River project. The circumstances of Brandon Shores had also required a BACT determination for SAM emissions. PEF had provided this as additional information to the Department in an earlier response; however, the State of Maryland had not yet issued a permit with respect to the applicant's proposed SAM limit. Maryland has since issued its "Recommended Licensing Conditions" (PSC Case No. 9075) that grants the applicant's proposed SAM limit of 0.027 lb/MMBtu.

    Therefore, PEF continues to believe that the SAM value of 0.012 lb/MMBtu, proposed for Crystal River, is appropriate for an existing boiler that is retrofitted with SCR and FGD controls. While not as stringent as the Department's proposed limit, it is much more stringent than the recent recommended limit for Brandon Shores. The Department's proposed SAM limit of 0.009 lb/MMBtu is unnecessarily stringent and leaves little, if any, compliance margin. Finally, in spite of the Department's contentions in the Technical Evaluation document, SAM control vendors contacted by PEF have not been willing to guarantee an overall control efficiency, given the uncertainties of the effects of other components in the exhaust gas stream on the overall SAM reduction.

    Response: EPA's RACT/BACT/LAER Clearinghouse does not provide an adequate list of units retrofit with SAM controls because many of these projects avoid PSD after applying controls. SAM emissions from Units 4 and 5 at this plant may increase substantially due to PEF's request to fire coal with much higher sulfur content. In the application, estimates of SAM emissions were very conservative at each step throughout the system resulting in a high final emissions rate. The BACT determination is based on information provided in support of the application as well as that available for the proposed control systems. No change was made.

13. In Condition 9c, there should be no imposition of an opacity standard during "startup, shutdown and malfunction" periods, as this is impractical to achieve and is inconsistent with current NSPS regulations (Subpart D which exempts startup, shutdown and malfunction through 40 CFR 60.11(c), the General Provisions in Subpart A). Initial discussions with the Department on this issue indicated an acknowledgement that this condition will be corrected in the final permit.

    Response: NSPS Subparts Da and Db each establish an opacity standard of 20%, except for one 6-minute period per hour of not more than 27%. However, Subpart Db also specifically states, "The particulate matter and opacity standards apply at all times, *except during periods of startup, shutdown or malfunction*." This statement is not included in Subpart Da, so the alternate opacity standard for startup, shutdown and malfunction was erroneously based on the NSPS Subpart Da standard. As mentioned by PEF, the following statement is included in the NSPS General Provisions of 40 CFR 60.11(c), "The opacity standards set forth in this part shall apply at all times *except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard*." This error was corrected by removing the alternate standard.

    In addition, with respect to the opacity standard, PEF believes that the Department went beyond its authority in lowering the normal operations opacity standard to 10%. Although this may have been consistent with estimates provided to the agency related to the ESP upgrade project, as stated above, more recent information submitted to the Department does not support lowering the standard below the current 20% opacity limit. This standard is far in excess of the NSPS for coal fired boilers and beyond BACT determinations for any existing, as well as most new coal fired boilers.

Response: The opacity standard is intended to reflect BACT and not the BACT floor, which is the NSPS. It was based on the information in PEF's request for bid requested by the Department.

PEF Comment: If the 10% opacity requirement remains as BACT, it should be clearly stated that annual compliance testing (via EPA Method 9) is the only required compliance verification and that the 10% BACT standard does not affect existing NSPS Subpart D requirements related to opacity monitoring and excess emissions and CMS reporting. As compliance would be determined by EPA Method 9, the opacity standard should be moved from Condition 9 ("Standards Based on CEMS/COMS") and placed in a separate condition. That condition should clarify that EPA Method 9 is the compliance method and that "at the option of the applicant" COMS data may be used in lieu of EPA Method 9. Proposed wording is as follows:

> "*Opacity:* Demonstrate compliance with the opacity limit by using visible emissions readings conducted in accordance with EPA Method 9. These readings must be taken annually by a certified observer, for at least one hour in duration during normal source operation. These EPA Method 9 readings will occur only during months when the source operates at normal conditions for at least 24 consecutive hours and weather/lighting conditions are conducive to taking proper EPA Method 9 readings. This requirement will become effective upon installation of the FGD system".

While it may be necessary to install COMs in each unit's ductwork for NSPS purposes, PEF cautions that the data generated should not be relied on for compliance purposes. There are several reasons for this. When a new FGD is installed, the opacity monitor moves from dry stack to FGD inlet duct(s). PS-1 requires four duct diameters downstream and two duct diameters upstream of disturbance. Six duct diameters of straight duct may not be possible, due to space limitations, and an alternate, less representative location may be necessary. This may introduce additional error into the opacity measurements. Further, FGD units with multiple ESP outlet ducts require an opacity monitor and flow signal on each duct. The current duct configuration may require multiple opacity monitors on each unit. Calculating an equivalent stack exit opacity value from several duct opacity monitors requires a complex formula using optical density, flow, and path length. Finally, keeping opacity monitors aligned on ducts is much more difficult than on stacks.

Response: As previously acknowledged, COMS will not be required on the new stack due to wet flue gas conditions caused by the FGD system. Although COMS will be installed in the ductwork just after the ESP, this is not necessarily indicative of the final stack opacity because the measurement will be taken before any additional control by the wet scrubber system. Therefore, Condition 9c was deleted as a COMS requirement and the remainder of this condition renumbered. Under "Standards Based on Stack Tests", the following requirement was added as Condition 8e, "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%." This change was also made in Appendix E, which summarizes the final BACT determinations.

14. In Condition 9e (renumbered as 9d in final permit), revise the language as follows: "Within ~~15~~ 24 months of commencing commercial operation of each unit with the new low-NOx burners, the permittee shall submit an application proposing a revised ~~(lower)~~ final BACT standard." If normal operation indicates that a higher permit limit is appropriate, PEF would like the ability to adjust the permit limit as appropriate.

    Response: Due to the extensive work involved in this project and the capability of firing different fuel blends, the condition was revised as follows, "Within ~~15~~ 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 ~~the~~ initial ~~12 months of~~ operation after completing installation of the new low-NO_X burners. There may be separate standards proposed for different fuels." The word "lower" was not deleted because the purpose of the condition is to allow sufficient time for operators to shakedown the equipment and establish good operating practices expected to lower the actual emissions rate.

15. The reference in Condition 13 to opacity monitoring should be revised to indicate that COMS will be installed in the ductwork prior to the FGD and not on the stack. The language should state that "the monitors will 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."

    Response: The condition was clarified as follows, "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 ~~COMS and~~ CEMS to ~~on~~ 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."

16. Condition 15 references Appendix F of the permit, which is intended to address only CEMS and not COMS. Appendix F should be updated to the current version of "Appendix CEMS" (February 15, 2007). Finally, as discussed earlier, while excess emissions are measured by a continuous monitoring system under the applicable NSPS, the COMS would not be required for compliance with the opacity BACT limit which will be measured at the stack. Opacity should be removed from this condition.

    Response: The only requirement for COMS in Appendix F is to continue to meet the applicable performance specifications and quality assurance procedures for the existing COMS. Condition 13 of the permit already requires that the monitors be installed, operated and maintained in accordance with the existing requirements of 40 CFR 60.45. Therefore, the references to COMS were removed from Appendix F.

17. In Condition 19a, remove the last sentence, as PEF would like to reserve the ability to retest the unit at 90% to 100% of the 7200 MMBtu/hr heat input rate to regain any lost capacity.

    Response: Once construction is complete, the permit requires the initial tests to be conducted at permitted capacity, which is defined in Rule 62-297.310(2), F.A.C. as 90% to 100% of the maximum operation rate allowed by the permit. Should initial problems prevent operation at full load, the permit does not preclude retesting at permitted capacity to show compliance. The condition reserves the right of the Department to revise the permitted capacity if a unit is unable to achieve the rated maximum operating rate with the installed equipment. A permitting note was added and the last sentence of this condition was revised to, "All initial tests shall be conducted with the emissions units operating at ~~90% to 100% of the~~ permitted capacity ~~specified by this permit~~ (within at least 90% of 7200 MMBtu/hour ~~based on a 24-hour average~~); 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."

18. Remove Condition 19c, which requires testing at the highest expected sulfur level and retesting if the actual sulfur content of the coal blend increases by 0.5% by weight or more. This requirement is very burdensome. It is difficult to purchase coal with specific levels of sulfur content. Annual test requirements should account for the variability of the sulfur level in the various coals combusted.

    Response: PM and SAM emissions are dependent on the fuel sulfur content and compliance is demonstrated by stack test. Therefore, it is important to ensure compliance is demonstrated under the high sulfur conditions. The condition simply requires new PM and SAM compliance testing if the fuel sulfur levels jump by 0.5% by weight or more. Once compliance is demonstrated for the highest sulfur levels (2.63% to 3.13% sulfur by weight), subsequent tests shall be conducted with the highest sulfur content representative of the actual coal blends being fired. The following clarifications were made:

    > "Initial ~~C~~compliance tests shall be conducted with the highest sulfur content representative of the actual coal blends ~~that will be~~ing fired. ~~If~~ 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 ~~last~~ highest tested sulfur content that demonstrated compliance ~~test~~, 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."

19. On page 11, Condition 19d, PEF requests removal of the phrase "Except for the initial tests", as PEF would like to reserve the ability to retest the unit at 90 to 100 percent of the 7,200 MMBtu/hr heat input rate to regain any lost capacity.

    Response: Once the initial tests are satisfied, Condition 19d allows the following, "... 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." See Comment 18 for the changes regarding initial testing. No additional changes were made.

20. In Condition 21, the last sentence is incomplete.

    Response: This sentence was revised to, "The stack test report shall also ~~report~~ indicate all required operational data collected during each test run."

21. In Condition 23, please remove "and the higher heating value (HHV)". HHV vs. LHV is typically not defined in coal analyses. Also, as mentioned in Comment 10, PEF requests a revision of the 30-day rolling average to an annual average.

    Response: Although slight, there is a measurable difference between HHV and LHV for coal. PEF provided additional information indicating that the maximum heat input rates were based on HHV. No change was necessary.

22. In Condition 24, remove "higher heating value HHV" and replace with "the heating value of the ash". There should not be any hydrogen in the ash to distinguish between HHV and LHV.

    Response: For ash, there is a negligible difference between HHV and LHV. The condition was revised as requested.

23. On page 12, Condition 25, please remove the ammonia injection rate in "a", the limestone slurry injection rate in "b", and precipitator monitoring in "d". Emission limits for the respective pollutants will be monitored with the CEMs system and the opacity monitoring requirement. With respect to the monitoring of ESP current and voltage, PEF had previously conducted an analysis of these parameters for suitability of use in a CAM plan for PM compliance and found there to be little correlation. The Utility Air Regulatory Group (UARG) has submitted similar comments to the EPA regarding their proposed amendments to the NSPS, Subpart Da.

    Response: For the installed control systems, PEF will need to monitor and record the SCR ammonia injection rate and the limestone slurry injection rate to adjust these parameters for proper operation. No change was made to these parameters. PEF provided additional information regarding the ESP power input. Based on the number of fields and the low correlation, this requirement was revised as follows, "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. ~~current and voltage to determine the secondary power input to the ESP. Data shall be reduced to 1-hour and 3-hour block averages.~~ Operation of the ESP shall be based upon COMS data collected ~~performance~~ during satisfactory PM emissions compliance tests." These changes were also made in Condition 20 and Appendix E (a summary of the final BACT determinations).

24. In Subsection B for the material handling operations, PEF requests several revisions to the Process Description section that is prior to the permit conditions. In addition to some corrections, the changes are intended to provide acceptable process descriptions in more general terms and eliminate specific terms such as "conveyors G1A" because the final design has not yet been completed. In Condition 2, PEF requests that the dust control technique for the wet ball mill grinder be changed from "enclosure/wet" to "wet".

    Response: The requested changes to the Process Description were made except for identifying some of the operating parameters, which were noted as being based on the "preliminary design". The requested change to Condition 2 was made as the material will be very wet at this point. This change was also made in Appendix E, which summarizes the final BACT determinations.

25. In Subsection E, the test burn should be designated for Units 1 and 2, as well as Units 4 and 5. Also, the sentence in Condition E.1 should be revised as follows: "The preliminary design is to spray the fuel additive on the coal prior to combustion ~~in the gravimetric feeders~~."

    Response: The clarifications and changes were made. Units 1 and 2 were added as affected units to Section 1 of the permit.

26. In Subsection B, remove the word "ash" form the material handling provisions for limestone and gypsum in Conditions 11 and 12.

    Response: The corrections were made.

CONCLUSION

The final action of the Department is to issue the permit with the minor revisions, corrections, and clarifications as described above.

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.

To provide full flexibility in implementing the federal cap and trade program for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) under the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR), the permittee elects to install 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. Because CAIR and CAMR afford the flexibility to evaluate market conditions to determine whether it will install controls, operate existing controls, or purchase allowances generated by other plants, the Department does not require the installation of this equipment nor its operation. However, other changes requested by the permittee 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™) 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

Title III: The existing facility is a major source of hazardous air pollutants.

Title IV: The existing facility operates units subject to the Acid Rain provisions.

Title V: The existing facility is a Title V major source of air pollution.

PSD: The existing facility is a major stationary source.

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 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. CAIR Project: For Units 4 and 5, the permittee is authorized to perform the following type of work to provide full flexibility in implementing the federal cap and trade program for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) under the Clean Air Interstate Rule (CAIR).

   a. *Low-NO_X Burners*: The permittee is authorized 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 authorized 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 authorized 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 CAIR 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) 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.
   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 0.47 lb/MMBtu of heat input 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) 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 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) 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. [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 emissions standards of this permit. No other periods of excess emissions are authorized. [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 achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup. [Rules 62-4.070(3) 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 reestablishing commercial operation of 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. [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 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. <u>Common Testing Requirements</u>: 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. <u>Test Methods</u>: 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
9	Method for Determining Opacity Observations

EPA Method	Description of Method and Comments
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 1st to September 30th), 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.]

B. Material Handling Activities for Limestone and Gypsum

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 be designed to receive limestone delivered to the plant by: conveyor from an adjacent quarry, or 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 the quarry delivery conveyor; truck unloading feeders; unloading and stacking belt conveyors to transfer limestone to a covered storage pile; a portal scraper reclaimer and an emergency reclaim feeder located inside a limestone storage building; crusher feed belt conveyors to transfer limestone to a crusher building for limestone sizing; plant feed belt conveyors; and silo feed belt conveyors to transfer limestone to the day silos.

Limestone received from the quarry conveyor will be transported to the unloading conveyor by the transfer conveyor. Limestone received by trucks will be transferred to the unloading conveyor by the truck unloading feeders. The delivered limestone will be conveyed to a covered storage pile via conveyor system. From the storage pile, the material is reclaimed using a single full portal scraper reclaimer and conveyed to a crusher building where the material is sized using crushers. One or more feed conveyors will receive limestone from the crushers and distribute the material to the three limestone day silos.

The plant feed conveyor(s) will be equipped with a diverter gate and will supply limestone to the first limestone day silo (Silo A) directly via a chute and to the other limestone day silos (Silos B & C) using silo feed conveyors equipped with diverter gates. Each limestone silo will be equipped with a pulse-jet fabric filter dust collection system. Insertable dust collectors will be provided at each of the truck unloading feeders and at the loading points of the silo feed conveyors. A dust collection system will be provided for the crusher building. 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.

The limestone preparation system includes wet ball mill grinding systems to produce the limestone slurry. Filtrate-recycle water from the FGD system will be used to prepare the limestone slurry to conserve make-up water for FGD system mist eliminator washing. The preliminary design is based on a feed rate of approximately 352 gpm of limestone slurry consisting of 25% to 30% solids with a specific gravity of 1.22. 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. Based on the preliminary design, the incoming gypsum slurry will contain approximately 18 to 22% suspended solids. Using a series of hydro-cyclones and 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.

Belt conveyors collect dewatered gypsum from the vacuum belt filters at the dewatering system. Under normal operating conditions, the conveyors will feed gypsum onto the belt of the transfer conveyor, which transfers the gypsum onto a belt feed conveyor for delivery to an adjacent (proposed) wallboard plant. In the reverse direction, the gypsum conveyor will feed gypsum onto another belt, which delivers gypsum to the emergency gypsum pile. The emergency gypsum pile will be used primarily to store the gypsum upon loss of the gypsum transfer and feed conveyors. In addition, the emergency pile may be used to store "off-specification" gypsum if needed. Trucks will remove gypsum from the emergency gypsum stockpile. Fugitive dust emissions will be minimal because the dewatered gypsum still contains at least 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	Flow Rate	Outlet Dust Loading Specification
Dry Limestone Handling System				
Limestone conveyors (general)	---	enclosed	---	---
Limestone stacking conveyor (discharge to)	---	dust suppressant	---	---
Dump trucks	---	covered	---	---
Truck unloading feeders w/integral hoppers	EP-000	dust collectors	acfm	0.010 grains/dscf
Limestone storage	---	covered pile	---	---
Limestone crushing and sizing	EP-000	enclosed building w/baghouse	acfm	0.010 grains/dscf
Limestone silo feed conveyors	EP-000	dust collectors	acfm	0.010 grains/dscf
Limestone day silos, up to (4)	EP-000	baghouse	acfm	0.010 grains/dscf
Limestone Preparation System				
Wet ball mill grinders and misc. equipment	---	wet	---	---
Gypsum Dewatering System				
Gypsum dewatering system	---	enclosure/wet	---	---
Gypsum Handling System				
Gypsum handling system	---	enclosure/wet	---	---

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 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.]

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 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.]

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. 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]

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 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.]

12. 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

13. 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.]

14. 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.]

15. 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 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.]
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

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;
    b. Determination of Prevention of Significant Deterioration; and
    c. Compliance with New Source Performance Standards.

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 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, 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.

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.

STANDARD CONTINUOUS MONITORING REQUIREMENTS

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.]

NEW SOURCE PERFORMANCE STANDARDS

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.

40 CFR 60, NSPS SUBPART A - GENERAL PROVISIONS

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-INSTITUTIONAL STEAM GENERATING UNITS

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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 30^{th} day following the end of each reporting period.