



# Department of Environmental Protection

Jeb Bush  
Governor

Twin Towers Office Building  
2600 Blair Stone Road  
Tallahassee, Florida 32399-2400

Colleen M. Castille  
Secretary

December 17, 2004

Mr. Rodney Williams, Plant Manager  
New Hope Power Partnership - Okeelanta Cogeneration Plant  
8001 U.S. Highway 27 South  
South Bay, FL 33493

Re: Draft Air Permit No. PSD-FL-196(P)  
Project No. 0990332-017-AC  
Okeelanta Cogeneration Plant  
Generating Capacity Increase to 140 MW

Dear Mr. Williams:

On September 3, 2004, New Hope Power Partnership submitted an application to add a nominal 65 MW steam turbine electrical generator to the existing Okeelanta Cogeneration Plant, which is located off of U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida. Enclosed are the following documents: "Technical Evaluation and Preliminary Determination", "Draft Permit", "Written Notice of Intent to Issue Air Permit", and "Public Notice of Intent to Issue Air Permit".

The "Technical Evaluation and Preliminary Determination" summarizes the Bureau of Air Regulation's technical review of the application and provides the rationale for making the preliminary determination to issue a draft permit. The proposed "Draft Permit" includes the specific conditions that regulate the emissions units covered by the proposed project. The "Written Notice of Intent to Issue Air Permit" provides important information regarding: the Permitting Authority's intent to issue an air permit for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue an air permit; the procedures for submitting comments on the Draft Permit; the process for filing a petition for an administrative hearing; and the availability of mediation. The "Public Notice of Intent to Issue Air Permit" is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project.

As this project is subject to the power plant site certification requirements, a final permit cannot be issued until after the required hearing on this project. If you have any questions, please contact the Project Engineer, Jeff Koerner, at 850/921-9536.

Sincerely,

Trina Vielhauer, Chief  
Bureau of Air Regulation

Enclosures

"More Protection, Less Process"

Printed on recycled paper.

**WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT**

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*In the Matter of an  
Application for Air Permit by:*

New Hope Power Partnership  
Okeelanta Cogeneration Plant  
8001 U.S. Highway 27 South  
South Bay, FL 33493

*Authorized Representative:*

Mr. Rodney Williams, Plant Manager

Draft Air Permit No. PSD-FL-196(P)  
Project No. 0990332-017-AC  
Okeelanta Cogeneration Plant  
Generating Capacity Increase to 140 MW  
Palm Beach County, Florida

**Facility Location:** New Hope Power Partnership operates an existing cogeneration plant located off of U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida.

**Project:** The applicant proposes to install a nominal 65 MW steam turbine electrical generator, a second cooling tower, and other miscellaneous support equipment. Upon completion of the project, the cogeneration plant will have a nominal generating capacity of 140 MW of electricity. Therefore, the project subjects the facility to the power plant site certification requirements of the Department. Details of the project are provided in the application and the enclosed "Technical Evaluation and Preliminary Determination".

**Permitting Authority:** Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

**Project File:** A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the project file is available at the Air Resource Section of the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-3381 (Phone: 239/332-6975). A copy of the project file is also available at the Air Pollution Control Section of the Palm Beach County Health Department, 901 Evernia Street, West Palm Beach, Florida 33401 (Phone: 561/355-3136).

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

**Public Notice:** Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed "Public Notice of Intent to Issue Air Permit" (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at the address or phone number listed above. Pursuant to Rule 62-110.106(5), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within seven (7) days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

**Comments:** The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked, and all email or facsimile

**WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT**

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comments must be received by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address, email or facsimile. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at <http://tlhora6.dep.state.fl.us/onw> and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

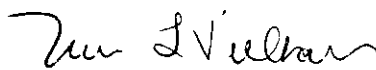
**Petitions:** A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's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

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

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue Air Permit is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3), F.S.

**Mediation:** Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.



Trina Vielhauer, Chief  
Bureau of Air Regulation

**WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT**

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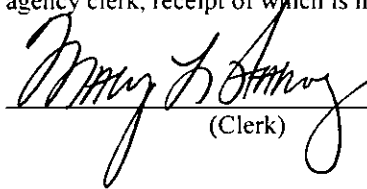
**CERTIFICATE OF SERVICE**

The undersigned duly designated deputy agency clerk hereby certifies that this "Written Notice of Intent to Issue Air Permit" package (including the Public Notice, the Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (\*) and copies were mailed by U.S. Mail before the close of business on 12/20/04 to the persons listed below.

- Mr. Rodney Williams, NHPP\*
- Mr. James Meriwether, NHPP
- Mr. David Buff, Golder Associates Inc.
- Mr. David Dee, Landers and Parsons\*
- Mr. James Stormer, PBCHD
- Mr. Ron Blackburn, SD Office
- Mr. Gregg Worley, EPA Region 4
- Mr. John Bunyak, NPS

Clerk Stamp

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

  
\_\_\_\_\_  
(Clerk)

12/20/04  
(Date)

## PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection  
Project No. 0990332-017-AC / Draft Air Permit No. PSD-FL-196(P)  
New Hope Power Partnership – Okeelanta Cogeneration Plant  
Palm Beach County, Florida

**Applicant:** The applicant for this project is the New Hope Power Partnership. The applicant's authorized representative is Mr. Rodney Williams, the Plant Manager of the Okeelanta Cogeneration Plant. The applicant's mailing address is the 8001 U.S. Highway 27 South, South Bay, Florida 33493.

**Facility Location:** The New Hope Power Partnership operates the existing Okeelanta Cogeneration Plant located off of U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida.

**Project:** The applicant operates an existing cogeneration plant, which was originally permitted in 1993 and began operation in 1997. The existing plant currently consists of three boilers, biomass storage/handling, a 74.9 MW steam turbine electrical generator, a condenser, a mechanical draft cooling tower, an electrical switchyard, and miscellaneous support equipment. Each boiler fires biomass (bagasse and wood chips) as the primary fuel. Distillate oil and natural gas are fired as startup and supplemental fuels. The applicant proposes to install a nominal 65 MW steam turbine electrical generator, a second cooling tower, and other miscellaneous support equipment. The existing cogeneration plant is located in Palm Beach County, an area that is currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or otherwise designated as unclassifiable. The cogeneration plant is a major facility in accordance with Rule 62-212.400, F.A.C., the regulatory program for the Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, new projects at the existing facility must be reviewed for PSD applicability.

In October of 2003, the Department issued a PSD permit modification for the cogeneration facility that increased the maximum heat input rate to the boilers from 715 to 760 MMBtu and allowed full operation. Based on potential emissions increases, the project was subject to PSD preconstruction review for carbon monoxide, nitrogen oxides, particulate matter, sulfur dioxide, volatile organic compounds, lead, fluorides, and sulfuric acid mist. The Department made a determination of the Best Available Control Technology (BACT) for each of these pollutants based on the following air pollution control equipment: low-NO<sub>x</sub> gas burners, over fire air, and a selective non-catalytic reduction system to reduce nitrogen oxides emissions; mechanical dust collectors followed by an electrostatic precipitator to reduce particulate matter emissions; and the efficient combustion of clean, low-sulfur fuels to minimize emissions of carbon monoxide, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. Based on the supporting air quality analysis of the potential impacts from increased operation, the applicant provided the Department with reasonable assurance that the project would not significantly contribute to or cause a violation of any state or federal ambient air quality standards and would not significantly contribute to or cause a violation of any PSD Class I or Class II increments.

For this project, it is presumed that the federally enforceable unit-specific allowable emissions from the cogeneration boilers are equivalent to the actual emissions from the boilers. This presumption is based on the following: the specific details of the project; the previous PSD modification permitting full operation of the cogeneration plant; the timing of the previous project that evaluated full operation; the previous BACT determinations and control equipment for the cogeneration boilers; the previous air quality analysis that evaluated the impacts of the full potential emissions increases; and the definition of actual emissions in Rule 62-210.200(11), F.A.C. Particulate matter emissions from the new cooling tower are estimated to be less than 2 tons per year. Therefore, there will not be a PSD significant emissions increase and the proposed project is not subject to PSD preconstruction review. However, the project does require a modification of the PSD permit to authorize the requested construction and remove the previous limitation on electrical power production. In addition, upon completion of the project, the cogeneration plant will have a nominal steam-generated electrical capacity of 140 MW. Therefore, the project subjects the facility to the power plant site certification requirements of the Department.

**Permitting Authority:** Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114 and fax number is 850/921-9533.

**Project File:** A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application,

(Public Notice to be Published in the Newspaper)

## PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the project file is available at the Air Resource Section of the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-3381 (Phone: 239/332-6975). A copy of the project file is also available at the Air Pollution Control Section of the Palm Beach County Health Department, 901 Evernia Street, West Palm Beach, Florida 33401 (Phone: 561/355-3136).

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**Comments:** The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked, and all e-mail or facsimile comments must be received by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address, email or facsimile. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at <http://tlhora6.dep.state.fl.us/onw> and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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

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

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue

(Public Notice to be Published in the Newspaper)

## **PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT**

Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue Air Permit is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3), F.S.

**Mediation:** Mediation is not available in this proceeding.

# DRAFT PERMIT

## PERMITTEE

New Hope Power Partnership  
Okeelanta Cogeneration Plant  
8001 U.S. Highway 27 South  
South Bay, FL 33493

*Authorized Representative:*

Mr. Rodney Williams, Plant Manager

Air Permit No. PSD-FL-196(P) Project No. 0990332-017-AC Okeelanta Cogeneration Plant SIC No. 4911 Palm Beach County
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## FACILITY

The facility consists of two adjacent plants. Okeelanta Corporation (ARMS ID No. 0990005) operates a sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) including packaging and transshipment activities. New Hope Power Partnership (ARMS ID No. 0990332) operates a nominal 140 MW cogeneration plant that provides process steam for the sugar mill/refinery and generates electricity for sale to the power grid (SIC 4911). The cogeneration plant, sugar mill, and sugar refinery are all considered a single facility for purposes of the PSD and Title V regulatory programs. The facility is located off U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida. The UTM coordinates are Zone 17, 524.90 km East, and 2940.10 km North. The map coordinates are latitude 26° 35' 00" N and longitude 80° 45' 00" W.

## STATEMENT OF BASIS

This PSD air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Part 52, Section 21 of the Code of Federal Regulations. Specifically, this permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality in accordance with Rule 62-212.400, F.A.C. The proposed project is subject to Power Plant Site Certification because the cogeneration plant will be able to generate more than 75 MW of steam generated electrical power. Key conditions of this PSD permit will become provisions of the site certification. The permittee is authorized to perform the proposed work and operate the installed equipment in accordance with the conditions of this permit, the conditions of the Title V operation permit, and as described in the application, approved drawings, plans, and other documents on file with the Department.

## CONTENTS

- Section I. General Information
- Section II. Administrative Requirements
- Section III. Emissions Units Specific Conditions
- Section IV. Appendices

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Michael G. Cooke, Director  
Division of Air Resources Management

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Effective Date



**SECTION I. GENERAL INFORMATION**

**PROJECT DESCRIPTION**

The existing cogeneration plant consists of three biomass fired boilers and a 74.9 MW steam turbine electrical generator. A new steam turbine electrical generator with a nameplate capacity of 70 MW will be added to the existing cogeneration plant. The new steam turbine electrical generator is expected to produce an incremental peak output of approximately 65 MW, which will increase the plant's production capacity to a nominal 140 MW. This permit authorizes the construction of the nominal 65 MW steam turbine electrical generator, a 2-cell mechanical draft cooling tower, and other miscellaneous support equipment. The following emissions units are regulated by this permit.

Facility ID No. 0990332

ID	Emission Unit Description
001	Cogeneration Boiler A (760 MMBtu per hour)
002	Cogeneration Boiler B (760 MMBtu per hour)
003	Cogeneration Boiler C (760 MMBtu per hour)
004	Material handling and storage
005	Miscellaneous support equipment (steam turbine electrical generators, condensers, cooling towers, etc.)

**REGULATORY CLASSIFICATION**

Title III: The facility is a potential major source of hazardous air pollutants (HAPs).

Title IV: The facility does not operate any units subject to the acid rain provisions of the Clean Air Act.

Title V: The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The facility is a PSD major source of air pollution with respect to Rule 62-212.400, F.A.C.

PPSC: The facility is subject to Chapter 62-17, F.A.C. for Power Plant Site Certification because it produces more than 75 MW of steam-generated electrical power.

NSPS: The facility operates units subject to the New Source Performance Standards in 40 CFR 60, including Subparts Da and Db (boilers) and Subpart Kb (fuel storage tanks).

NESHAP: The facility operates existing boilers that will be subject to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) in Subpart DDDDD of 40 CFR 63.

**PERMITTING AUTHORITY**

All documents related to applications for permits to construct, modify or operate shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of the applications shall be submitted to each Compliance Authority.

**COMPLIANCE AUTHORITY**

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Pollution Control Section of the Palm Beach County Health Department at P.O. Box 29, West Palm Beach, Florida 33402-0029. Copies of all such documents shall be submitted to the Air Resources Section at the South District Office of the Florida Department of Environmental Protection (DEP) at 2295 Victoria Avenue, Suite 364 in Fort Myers, Florida 33902-2549.

## SECTION I. GENERAL INFORMATION

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### RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Air Permit No. PSD-FL-196 issued September 27, 1993 and all subsequent modifications; and
- Application No. 0990332-017-AC received by the Department on September 3, 2004 and all related correspondence to make it complete.

For a brief history of the modifications to the PSD permit, refer to Appendix F.

### APPENDICES

The following Appendices are attached as part of this permit.

- Appendix A. Citation Format
- Appendix B. General Conditions
- Appendix C. Standard Requirements
- Appendix D. Final BACT Determinations
- Appendix E. Continuous Monitor Requirements
- Appendix F. Permitting History

### CITATION FORMAT

Appendix A of this permit describes the format used to cite applicable rules, regulations, and permitting actions.

### NOTES

This permit is a revision of the PSD air construction permit for the cogeneration plant. It does not impose any new initial testing requirements.

Permit

## SECTION II. ADMINISTRATIVE REQUIREMENTS

1. General Conditions: The permittee is subject to, and shall operate under, the attached General Conditions listed in Appendix B of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of each subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, and 60 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, 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 applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
3. Permit Expiration: The original expiration date for the construction of this plant was July 1, 1996. Construction of the original cogeneration plant is complete and commercial operation has commenced. The permit modification authorizes construction of a new steam turbine electrical generator, a new 2-cell mechanical draft cooling tower, and other support equipment. For purposes of installing the new equipment, the authorization to construct shall expire on **December 15, 2006**. [Rule 62-4.210(2), F.A.C.]
4. Effective Date: The effective date of the modified PSD permit is specified on the placard page (page 1).
5. Relaxations of Restrictions on Pollutant Emitting Capacity: If a previously permitted facility or modification becomes a facility or modification which would be subject to the preconstruction review requirements of this rule if it were a proposed new facility or modification solely by virtue of a relaxation in any federally enforceable limitation on the capacity of the facility or modification to emit a pollutant (such as a restriction on hours of operation), which limitation was established after August 7, 1980, then at the time of such relaxation the preconstruction review requirements of this rule shall apply to the facility or modification as though construction had not yet commenced on it. [Rule 62-212.400(2)(g), F.A.C.]
6. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
7. 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. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]
8. Title V Permit Revision: Pursuant to Rule 62-213.420(1)(a)2, F.A.C., the permittee shall submit an application for a revised Title V air operation permit at least ninety (90) days before the expiration of this permit, but no later than 180 days after commencing operation. In accordance with Rule 62-213.412(2), F.A.C., the permittee may immediately implement the changes authorized by this air construction permit after submitting the application for a revised Title V air operation permit to the Permitting Authority and providing copies of the application to EPA Region 4 and each Compliance Authority. To apply for a revised 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. As necessary, the application shall include a Compliance Assurance Monitoring Plan. The application shall be submitted to the Department's South District Office with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, 62-213.412, and 62-213.420, F.A.C.]

### SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

This section of the permit addresses the following emissions units.

#### **Emissions Units 001, 002, and 003: Cogeneration Boilers A, B, and C**

*Description:* Each unit is a biomass-fired spreader stoker steam boiler manufactured by Zurn and designed to produce approximately 506,100 pounds per hour of steam at 1500 psig and 975° F.

*Fuels and Capacity:* The primary fuel is biomass (760 MMBtu per hour), which includes bagasse from the adjacent sugar mill and clean wood material delivered to the plant by area subcontractors. Auxiliary fuels include natural gas (605 MMBtu per hour) and very low sulfur distillate oil (490 MMBtu per hour).

*Controls:* Pollution control equipment includes low-NOx burners for gas firing, a selective non-catalytic reduction system to reduce nitrogen oxides emissions, mechanical dust collectors and an electrostatic precipitator to reduce particulate matter emissions, and an activated carbon injection system to reduce potential mercury emissions. Good operating practices and the efficient combustion of clean, low-sulfur fuels minimizes emissions of carbon monoxide, sulfuric acid mist, sulfur dioxide, and volatile organic compounds.

*Stack Parameters:* Exhaust gases exit a 10 feet diameter stack that is at least 199 feet tall and with a volumetric flow rate of approximately 319,000 acfm at 352° F.

**Emissions Unit 004: Material handling and storage** including unloading operations, stockpiles, transfer operations, conveyors, screens, crushers, hoppers, silos, and storage tanks.

**Emissions Unit 005: Miscellaneous Support Equipment** including a nominal 75 MW steam turbine electrical generator, a nominal 65 MW steam turbine electrical generator, condensers, two cooling towers, a switchyard, etc.

#### **CONSTRUCTION DETAILS**

- New Construction:** The existing cogeneration plant includes a nominal 75 MW steam turbine electrical generator and a mechanical draft cooling tower. This PSD modification authorizes the addition of a nominal 65 MW steam turbine electrical generator and the addition of a 2-cell mechanical draft cooling tower. Within 10 days of establishing commercial operation of the new steam turbine electrical generator, the permittee shall notify the Bureau of Air Regulation and Compliance Authorities. The notification shall include the date of commercial startup and identify any substantial changes in the final equipment that differ from the application. [Design; Rule 62-4.070(3), F.A.C.] *{Permitting Note: Upon completion of the project, the cogeneration plant will have a nominal generating capacity of 140 MW. Therefore, the project subjects the facility to the power plant site certification requirements of the Department. Subsequent modifications must also be made in accordance with these requirements.}*
- Boiler Design:** The cogeneration boilers shall consist of spreader stoker units designed to fire biomass as the primary fuel with pipeline natural gas and distillate oil as auxiliary fuels. Natural gas and distillate oil are fired at startup and shutdown, when necessary to ensure good combustion, to supplement biomass fuel, and for periods when the biomass fuel supply is interrupted. No other fuels are authorized. *{Permitting Note: Each boiler was originally designed to fire low sulfur coal as an emergency backup fuel, but no transfer, crushing, or storage systems were ever installed. The permittee shall obtain a permit modification before firing any other fuel (including coal) not specifically authorized by this permit.}*
- Stack:** Each boiler shall have an individual stack that is at least 199 feet tall. The permanent stack sampling facilities for each stack must comply with Rule 62-297.345, F.A.C.
- Process Monitors:** Each boiler shall be equipped with instruments to measure the fuel feed rate, heat input, steam production, steam pressure, and steam temperature. Appendix E identifies minimum requirements for monitoring equipment.
- Control Equipment:** Each boiler shall be equipped with:
  - Low-NOx natural gas burners rated for no more than 0.15 pounds of NOx per MMBtu of heat input.

### SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

Four burners are installed with one in each corner of the boiler. The maximum heat input rate from all four burners is 605 MMBtu per hour.

- Mechanical dust collectors consisting of four, large diameter, multi-tube modules with airfoil vanes or equivalent equipment. The mechanical dust collectors shall be installed and maintained as pre-control devices prior to each electrostatic precipitator and designed for a removal efficiency of at least 85% of the particulate matter greater than 10 microns in size (assuming a specific gravity of 2.00).
  - An electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter.
  - A selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of NO<sub>x</sub>.
  - A carbon injection system (or equivalent) for potential control of mercury emissions.
6. Continuous Monitors: For each cogeneration boiler, the permittee shall install, calibrate, maintain, and operate continuous emissions monitoring systems (CEMS) and continuous opacity monitoring systems (COMS) to measure and record emissions of carbon monoxide (CO), nitrogen oxides (NO<sub>x</sub>), opacity, oxygen (O<sub>2</sub>), and sulfur dioxide (SO<sub>2</sub>) in a manner sufficient to demonstrate compliance with the standards of this permit. The opacity monitor shall be placed in the ductwork between the electrostatic precipitator and the stack or in the stack. Appendix E identifies minimum requirements for monitoring systems.
7. Good Combustion Practices: An oxygen meter shall be installed for each unit to continuously monitor a representative sample of the flue gas. The oxygen monitor shall be used with automatic feedback or manual controls to continuously optimize air/fuel ratio parameters. Depending on the fuel quality and existing combustion conditions, the operator shall provide sufficient excess air to ensure good combustion within the boiler. The application to revise the Title V operation permit shall identify "good combustion practices" for the cogeneration boilers to minimize pollutant emissions during startup, operation, and shutdown. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" shall be used as a guide. Good combustion controls shall also include the following:
- Maintain improved combustion controls to provide efficient tuning of air/fuel control instrumentation.
  - Maintain rotary pocket-style wood feeders with efficient air seal to minimize intrusion of ambient air.
  - Maintain effective water level controls in bottom ash system to prevent intrusion of ambient air.
  - Mix biomass fuel to provide a consistent fuel blend.
  - Maintain the flue gas oxygen content to provide efficient combustion for the existing conditions.
  - When necessary to enhance poor combustion, reduce the biomass feed rate below the maximum rate.
  - When necessary to enhance poor combustion, co-fire natural gas or distillate oil.
8. O&M Plans: The application to revise the Title V operation permit shall include an operation and maintenance plan consisting of at least the following items.
- a. For the cogeneration boilers, electrostatic precipitators (ESP), selective non-catalytic reduction (SNCR) systems, activated carbon injection (ACI) mercury control systems, and silo fabric filters, identify: the capacities, design efficiencies, pollutant emission rates, general operational description of equipment, key design and operating parameters, expected operating range of each key parameter, monitoring of key parameters, frequency of monitoring (instantaneous, continual, or continuous), and actions taken to return key parameters to within the expected operating ranges. The plan shall also specify good operating practices to promote efficient boiler combustion, startup and shutdown procedures for the boilers and control systems to minimize emissions, and precautions to prevent fugitive particulate matter emissions. *{Permitting Note: Operation outside of the specified operating range for any monitored parameter would not be a violation by itself. However, continued operation outside of a specified operating range without corrective action may be considered circumvention of the air pollution control equipment or methods.}*
  - b. For the selective non-catalytic reduction (SNCR) systems identify an alternate NO<sub>x</sub> emissions control

### SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

plan based on previous monitoring data that shall be implemented in case the NO<sub>x</sub> monitoring system is down. The plan shall identify the minimum urea injection rate that has demonstrated continuous compliance with the NO<sub>x</sub> emissions standard at various load conditions.

9. Materials Handling Controls: For the fly ash handling and mercury control system reactant storage systems:
- The particulate matter filter control system for the storage silos shall be designed to achieve an outlet dust loading of no greater than 0.01 grains per actual cubic feet of exhaust.
  - The fly ash handling system (including transfer points and storage bin) shall be enclosed. The ash shall be wetted in the ash conditioner to minimize fugitive dust prior to discharging to the disposal bin.

#### OPERATIONAL RESTRICTIONS

10. Permitted Capacity: The cogeneration boilers shall be constructed and operated in accordance with the capabilities and specifications described in the application. The maximum heat input rate to each cogeneration boiler shall not exceed 760 MMBtu/hr when burning 100 percent biomass, 605 MMBtu/hr when burning 100 percent natural gas, and 490 MMBtu/hr when burning 100 percent very low sulfur distillate oil. The steam production of each boiler shall not exceed an average of 506,100 pounds per hour at 1,500 psig and 975°F. The operating hours of the cogeneration boilers are not restricted (8760 hours per year).
11. Primary Fuel: The primary fuel for the plant shall be biomass, which shall consist of bagasse and authorized wood material. Bagasse is the fibrous vegetative residue remaining after the sugarcane milling process. Authorized wood material is clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter. Each cogeneration boiler shall combust no more than 30% by weight yard waste (yard trash) on a calendar quarter basis that is defined as a municipal solid waste (MSW) in 40 CFR 60.51a. The biomass fuel used at the cogeneration plant shall not contain hazardous substances, hazardous wastes, biomedical wastes, or garbage. The fuel used at the cogeneration plant shall not contain special wastes, except wood, lumber, trees, tree remains, bagasse, cane tops and leaves, and other clean vegetative and cellulose matter. The permittee shall perform a daily visual inspection of any wood material or similar vegetative matter that has been delivered to the plant for use as fuel. Any shipment observed to contain prohibited materials shall not be used as fuel, unless such materials can be readily segregated and removed from the wood material and vegetative matter.

The permittee shall design and implement a management and testing program for the wood material and other materials delivered to the plant for fuel. The program shall be designed to keep painted and chemically treated wood, household garbage, toxic or hazardous non-biomass and non-combustible waste material, from being burned at this plant. The program shall provide for the routine inspection and/or testing of the fuel at the originating wood yard sites as well as at the cogeneration site, to ensure that the quantities of painted or chemically treated wood in the fuel are minimized. Based on the analysis of a composite sample, wood material containing more than 70.7 ppm arsenic or 83.3 ppm chromium or 62.8 ppm copper shall not be burned. Fuel scheduled for burning shall be inspected daily. At a minimum, the fuel management program shall include the following sampling and analyses:

- At least twice each month, the permittee shall have separate analyses conducted on an as-fired wood sample and an as-fired bagasse sample for the following: heating value (modified ASTM D3286, Btu/lb, dry), carbon content (modified ASTM D5373, percent by weight, dry), sulfur content (modified ASTM D4239 Method C, percent by weight, dry), and moisture content (modified ASTM D3173, percent by weight). In addition the wood sample shall be analyzed for copper, chromium, and arsenic in accordance with Methods 3050/6010 (EPA Method SW-846) and reported in ppm by weight, dry. Samples shall be taken at least two weeks apart.
- At least once each month, the permittee shall have an analysis conducted on a composite sample of fly ash and bottom ash for arsenic, copper, and chromium in accordance with the procedures described in EPA Method SW-846, *Test Methods for Evaluating Solid Waste, Physical/Chemical Methods* (40 CFR

### SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

261, Appendix III). The analytical results from ash testing shall be used in conjunction with those from the as-fired wood samples to evaluate the effectiveness of the fuel management program in removing chemically treated wood from the biomass fuel. The permittee shall dispose of all ash generated on site in accordance with the applicable state and federal regulations.

- c. Analytical results of the as-fired biomass fuels and ash sampling shall be summarized and provided in the quarterly report to the Compliance Authority.

The ash and fuel management program shall become part of the Title V operation permit.

12. **Auxiliary Fuel:** The cogeneration boilers shall fire only distillate oil and pipeline natural gas as auxiliary fuels. Distillate oil shall be new No. 2 oil with a maximum sulfur content of 0.05 percent sulfur by weight as determined by the appropriate test method listed in 40 CFR 60.17. "New" oil is oil that has been refined from crude oil and that has not been used in any manner that may contaminate it. Each boiler may startup solely on pipeline natural gas or distillate oil.
13. **Fossil Fuel Limitation:** The firing of fossil fuels (distillate oil and natural gas) shall be less than 25 percent of the total heat input to each cogeneration boiler during any calendar quarter.
14. **Fuel Records:** The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, and sulfur content of each fuel oil delivery shall be kept in a log for at least five years. For each calendar month, the actual monthly SO<sub>2</sub> emissions and the 12-month rolling total SO<sub>2</sub> emissions shall be determined and kept in a log.
15. **Permanent Shutdown:** Sugar mill boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15 shall remain permanently shutdown and rendered incapable of operation. *{Permitting Note: Okeelanta Corporation's Boiler No. 16 may operate in accordance with modified Permit No. PSD-FL-169(A).}* [Rule 62-212.400, F.A.C.]

#### EMISSIONS LIMITING STANDARDS

16. **Emissions Standards:** Based on the maximum permitted heat input to each cogeneration boiler, stack emissions shall not exceed the standards specified in the following table:

Pollutant	Averaging Period	Emissions Standards per Boiler <sup>1</sup>	
		lb/MMBtu	lb/hr
Carbon Monoxide (CO) <sup>a</sup>	30-day rolling CEMS avg.	0.50	380.0
	12-month rolling CEMS avg.	0.35	
Nitrogen Oxides (NOx) <sup>b</sup>	30-day rolling CEMS avg.	0.15	114.0
Sulfur Dioxide (SO <sub>2</sub> ) <sup>c</sup>	24-hour rolling CEMS avg.	0.20	152.0
	30-day rolling CEMS avg.	0.10	
	12-month rolling CEMS avg.	0.06	
Stack Opacity <sup>d</sup>	6-minute block COMS avg. (Alternative: EPA Method 9)	≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity	
Particulate Matter (PM/PM <sub>10</sub> ) <sup>e</sup>	3-run test avg.	0.026	19.8
Volatile Organic Compounds (VOC) <sup>f</sup>	3-run test avg.	0.05	38.0
Mercury <sup>g</sup>	3-run test avg.	5.4 x 10 <sup>-06</sup>	NA
Lead and Fluorides <sup>h</sup>	The BACT determination for lead and fluoride emissions is the use of fuels containing low levels of these compounds (bagasse, wood, distillate oil, and natural gas) and prospective removal with the fly ash by the mechanical dust collectors and electrostatic precipitators.		

### SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

- a. Compliance shall be determined by data collected from the required CO CEMS in terms of "lb/MMBtu of heat input". The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and be consistent with the NO<sub>x</sub> monitoring requirements below. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period.
- b. Compliance shall be determined by data collected from the required NO<sub>x</sub> CEMS in terms of "lb/MMBtu of heat input". The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and the requirements of 40 CFR 60.13, 60.44a, 60.46a, 60.47a, 60.48a, and 60.49a. A boiler-operating day is any day in which any authorized fuel is fired.
- c. Compliance with the SO<sub>2</sub> standards shall be determined by data collected from the required SO<sub>2</sub> CEMS in terms of "lb/MMBtu of heat input". The 24-hour average shall be determined by calculating the arithmetic average of all valid hourly emission rates for 24 successive boiler-operating hours. The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler-operating days and the requirements of 40 CFR 60.13, 60.43a, 60.46a, 60.47a, 60.48a, and 60.49a. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period. Valid SO<sub>2</sub> hourly averages shall not be excluded from any compliance average. *{Permitting Note: Potential emissions of sulfuric acid mist are minimized by the effective control of SO<sub>2</sub> emissions with the firing of low sulfur fuels. For reporting purposes, sulfuric acid mist emissions shall be estimated as 6% of the total measured SO<sub>2</sub> emissions.}*
- d. Continuous compliance with the opacity standard shall be determined by data collected from the required COMS in terms of "percent opacity" based on 6-minute block averages. Alternatively, compliance may also be determined by conducting EPA Method 9 observations.
- e. Compliance with the particulate matter standards shall be determined by the average of three test runs conducted in accordance with EPA Method 5. For purposes of reporting PM<sub>10</sub> emissions, it shall be assumed that all particulate matter emitted is PM<sub>10</sub>.
- f. Compliance with the VOC standards shall be determined by the average of three test runs conducted in accordance with EPA Method 25A based on propane. In addition, the permittee may choose to conduct EPA Method 18 concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. Otherwise, all emissions measured by EPA Method 25A shall be considered "volatile organic compounds".
- g. Compliance with the mercury standards shall be determined by the average of three test runs conducted in accordance with EPA Method 101A or 29. Emissions in excess of this standard shall be a violation of the permit. In addition, if two or more cogeneration boilers exceed the annual mercury emission limit, the permittee shall reactivate the carbon injection system for all three units within 30 days of the stack test report due date. The minimum carbon injection rate shall be at least 7 pounds per hour. Within 60 days of the stack test report due date, the permittee shall submit to the permitting and compliance authorities a mercury testing protocol designed to establish an effective carbon injection rate to control mercury emissions. Within 60 days of receiving approval for the mercury testing protocol by the permitting authority, the permittee shall begin the approved testing program. At a minimum, the permittee shall submit a full engineering report summarizing the uncontrolled emissions, controlled emissions, fuels, operating capacities, and recommending a minimum activated carbon injection rate to control mercury emissions.
- h. The particulate matter standard is also a surrogate standard for lead emissions. *{Permitting Note: For reporting purposes, average lead emissions are expected to be  $2.6 \times 10^{-05}$  lb/MMBtu and average fluoride emissions are expected to be  $1.9 \times 10^{-04}$  lb/MMBtu when firing bagasse/wood.}*



### SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

- i. Each boiler shall comply with the standards when firing any combination of authorized fuels. The "lb/hour" rates are based on the highest emission standard shown for that pollutant. Required compliance tests shall be performed in accordance with the requirements of Condition No. 19. The cogeneration boilers are also subject to the new source performance standards (NSPS Subpart Da) for new electric utility steam generating units. These requirements include the general provisions of Subpart A in 40 CFR 60, as well as the following source-specific applicable requirements: 60.40a (Applicability and Designation of Affected Facility); 60.41a (Definitions); 60.42a (Standards for Particulate Matter); 60.43a (Standard for Sulfur Dioxide); 60.44a (Standard for Nitrogen Oxides); 60.46a (Compliance Provisions); 60.47a (Emissions Monitoring); 60.48a (Compliance Determination Procedures and Methods); and 60.49a (Reporting Requirements). The cogeneration boilers are also subject to Rule 62-296.405(2), F.A.C. (Fossil Fuel Steam Generators with more than 250 MMBtu per Hour of Heat Input), Rule 62-296.410, F.A.C. (Carbonaceous Fuel Burning Equipment), and Rule 62-296.570, F.A.C. (Reasonably Available Control Technology Requirements for Major VOC and NOx Facilities).

*{Permitting Note: Appendix D identifies the final BACT determinations for the cogeneration boilers.}*

17. **Material Handling:** The following conditions apply to the biomass, ash, and activated carbon handling facilities.
  - a. All conveyors and conveyor transfer points shall be enclosed to preclude PM emissions (except those directly associated with the stacker/reclaimer, for which enclosure is operationally infeasible).
  - b. Water sprays, chemical wetting agents, and/or stabilizers shall be applied to storage piles, handling equipment, unenclosed transfer points, etc. during dry periods and as necessary to prevent visible emissions. When adding, moving or removing material from the storage pile, visible emissions of no more than 20% opacity are allowed.
  - c. The mercury control system reactant storage silos shall be maintained at a negative pressure while operating with the exhaust vented to a filter control system. Visible emissions from any storage silo shall not exceed 5 percent opacity based on a 6-minute block average. A visible emissions test (EPA Method 9) shall be performed at least annually for each silo that is loaded with carbon during the federal fiscal year.

#### STARTUP, SHUTDOWN, AND MALFUNCTION

18. **Startup, Shutdown, and Malfunction Requirements:** The permittee shall comply with the following requirements regarding periods of startup, shutdown, and malfunction for each cogeneration boiler.
  - a. *Definitions*
    - 1) Excess emissions are emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions that occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]
    - 2) Startup is the commencement of operation of a boiler which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which may result in excess emissions. Periods of startup for each boiler shall end once steam generation reaches 150,000 pounds per hour. A cold startup is a startup after the boiler has been shutdown for 24 hours or more. A warm startup is a startup after the boiler has been shutdown for less than 24 hours.
    - 3) Shutdown is the cessation of the operation of a boiler for any purpose after steam generation drops below 150,000 pounds per hour.
    - 4) Malfunction is any unavoidable mechanical and/or electrical failure of air pollution control

### SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

- b. *Prohibition:* Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. Emissions data recorded during such preventable periods shall be included in the compliance averages. [Rule 62-210.700(4), F.A.C.]
- c. *Monitoring Data Exclusion:* Each continuous monitoring system shall operate and record data during all periods of operation (including startup, shutdown, and malfunction) except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Provided the operators implement best operational practices to minimize the amount and duration of emissions, the following conditions apply. Pursuant to Rules 62-210.700(1) and (5), F.A.C., these conditions consider the variations in operation of the cogeneration boilers.
- 1) Natural gas or distillate oil shall be fired during startup prior to energizing the electrostatic precipitator (ESP). Once the operating temperature recommended by the ESP manufacturer is maintained (approximately 340° F to 350 ° F), it shall be placed on line and the boiler shall comply with the opacity standard specified in Condition No. 16. The ESP shall be on line and functioning properly before firing any biomass. The opacity limit does not apply when the ESP is off line due to warm startup, cold startup, or shutdown. No more than twenty 6-minute block averages of opacity monitoring data shall be excluded in a 24-hour period due to documented malfunctions.
  - 2) Hourly CO and NOx emission rate values collected during startup, shutdown, or documented malfunction may be excluded from the 30-day and/or 12-month compliance averages. No more than six hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a cold startup. No more than three hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a warm startup. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a malfunction. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a shutdown. For each cogeneration boiler, no more than 183 hourly emission rate values shall be excluded during any calendar quarter.
  - 3) All valid hourly SO<sub>2</sub> emission rate values shall be included in all of the compliance averages. [40 CFR 60.46a and 60.49a]
  - 4) To "document" a malfunction, the operator shall notify the Compliance Authority within one working day of the malfunction by phone, facsimile, or electronic mail. The notification shall include the date and time of malfunction, a description of the malfunction and probable cause, steps to taken to minimize emissions, and actions taken to correct the problem. [Rules 62-210.700(6) and 62-4.130, F.A.C.]
- d. *Reporting:* In conjunction with the annual operating report, the permittee shall identify the number of startups, the number of shutdowns, and the number of malfunctions that occurred during the year for each boiler. For each boiler's CO and NOx monitors, the report shall identify the annual hours of emission data excluded from the compliance determination due to each type of incident (startups; shutdowns; and documented malfunctions).

[Rule 62-210.700, F.A.C.; Rule 62-4.070(3), F.A.C.; 40 CFR 60.8; and 40 CFR 60.46a]

#### COMPLIANCE METHODS AND REPORTING

##### 19. Stack Test Requirements

- a. *Initial Tests:* Initial tests were initially required for emissions of mercury, particulate matter, and volatile organic compounds. The Department may require these initial tests to be repeated if major physical or operational changes are made that affect main components such as the boiler, fuels, and/or

**SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS**

pollution control equipment.

- b. *Annual Tests:* At least once during each federal fiscal year, the permittee shall conduct compliance tests for emissions of mercury, particulate matter, and volatile organic compounds.
- c. *Renewal Tests:* Within the 12-month period prior to submitting an application to renew the Title V air operation permit, the permittee shall conduct compliance tests for emissions of, mercury, particulate matter, and volatile organic compounds. Tests shall be conducted at five-year intervals.
- d. *Test Procedures:* The emission compliance tests shall be conducted in accordance with the provisions of Chapter 62-297, F.A.C., 40 CFR 60.46a (NSPS Subpart Da), and as summarized in Appendix C of this permit. The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. The biomass fuel feed for each test run shall consist of at least 45% wood materials by weight. Testing of emissions shall be conducted with each cogeneration boiler operating at permitted capacity, which is defined as a heat input rate between 684 and 760 MMBtu/hour and firing 100% biomass. If it is impracticable to test at permitted capacity, a cogeneration boiler may be tested at less than the maximum permitted capacity; in this case, subsequent operation is limited to 110 percent of the test rate until a new test is conducted. Within three days of completing a test below permitted capacity, the permittee shall provide written notification of the restricted operational capacity to the Compliance Authority. 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. [Rule 62-297.310(7)(a)9, F.A.C. and 40 CFR 60.7, 60.8]
- e. *Test Methods:* Compliance with the emission limits specified in this permit shall be demonstrated using EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

EPA Method	Description
1	Selection of sample site and velocity traverses
2	Stack gas flow rate when converting concentrations to or from mass emission limits
3A	Gas analysis when needed for calculation of molecular weight or percent O <sub>2</sub>
4	Moisture content when converting stack velocity to dry volumetric flow rate for use in converting concentrations in dry gases to or from mass emission limits
5	Particulate matter emissions
6 or 6C	Sulfur dioxide emissions
7 or 7E	Nitrogen oxide emissions
9	Visible emissions determination of opacity <i>{Permitting Note: Although each unit is required to monitor opacity with a COMS, visible observations may also be used to demonstrate compliance.}</i>
10	Carbon monoxide emissions
12	Inorganic lead emissions
19	Calculation of sulfur dioxide and nitrogen oxide emission rates
25A	Volatile organic compounds emissions <i>{Permitting Note: EPA Method 18 may be conducted concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. Otherwise, all emissions measured by EPA Method 25A shall be considered "volatile organic compounds".}</i>
29	Multiple metals emissions
101A	Particulate and gaseous mercury emissions

### SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

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No other methods may be used to demonstrate compliance unless prior written approval is received from the Department. Other applicable testing requirements are included in Appendix C of the permit. The permittee shall use CEMS and COMS data to demonstrate compliance with the emissions standards for CO, NO<sub>x</sub>, opacity, and SO<sub>2</sub>. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

20. Continuous Monitor Requirements: The permittee shall demonstrate compliance with the emissions standards for CO, NO<sub>x</sub>, opacity, and SO<sub>2</sub> based on data collected from the continuous emissions monitoring systems (CEMS) and continuous opacity monitoring systems (COMS) required for each cogeneration boiler. Appendix E specifies the minimum requirements for monitoring equipment.
21. Quarterly Reports: For each cogeneration boiler, the permittee shall submit a quarterly report for each required continuous emissions and opacity monitoring system in accordance with the requirements specified in Appendix E of this permit. The permittee shall also submit a quarterly summary of the fuel analyses, fuel usage, and equipment malfunctions. For each malfunction, the report shall identify the cause (if known), and corrective actions taken. The quarterly reports and summaries shall be submitted to the Compliance Authority no later than 30 days following each calendar quarter.
22. 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. Along with this report, the permittee shall also submit a summary of CO emissions from each cogeneration boiler in terms of "ppmvd corrected to 3% oxygen based on a 24-hour average (day)" for each operational day. [Rule 62-210.370(2), F.A.C.]