Florida Department of

Memorandum Environmental Protection

TO: Clair Fancy, Chief, BAR aaf for CHF

THROUGH: Al Linero, Administrator - New Source Review Section aal 12/20

FROM: Jeff Koerner, New Source Review Section JK

DATE: December 20, 2001

SUBJECT: Project No. 0990332-014-AC
Draft Air Permit No. PSD-FL-196M
New Hope Power Partnershp - Okeelanta Cogeneration Plant
Revised PSD Air Permit

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination;
- Draft Permit; and
- PE Certification

The Technical Evaluation and Preliminary Determination provides a detailed description of the project, the rule applicability, and the BACT determinations. The P.E. certification briefly summarizes proposed project and BACT determinations. On October 23, 2001, the applicant waived the 90 day time clock requirements to submit a revised application. This project is nearly 12 months old because of numerous delays due to requests for supporting documentation based on CEMS data and modeling issues. Day #74 is February 21, 2002. I recommend your approval of the attached Draft Permit for this project.

CHF/AAL/jfk

Attachments

P.E. CERTIFICATION STATEMENT

PERMITTEE

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

Project No. 0990332-014-AC
Draft Permit No. PSD-FL-196M
Facility ID No. 0990332
SIC Nos. 2061, 2062, and 4911

PROJECT DESCRIPTION

New Hope Power Partnership operates the 74.9 net MW Okeelanta Cogeneration Plant adjacent to Okeelanta Corporation's sugar mill that is approximately six miles south of South Bay and off of U.S. Highway 27 in Palm Beach County, Florida. The original PSD permit established BACT standards for emissions of beryllium (Be), fluorides (Fl), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). Emissions of other regulated pollutants netted out of PSD based on emissions decreases from the shutdown of existing boilers at the adjacent sugar mill. The currently proposed project requires BACT determinations for emissions of carbon monoxide (CO), fluorides (Fl), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). Based on the applicant's requests, the following proposed changes were made to the original PSD permit.

- Coal was removed as an authorized fuel. All annual emissions were revised accordingly.
- The 30-day CO standard of 0.35 lb/MMBtu was revised to 0.50 lb/MMBtu. The draft permit also establishes a 12-month standard of 0.35 lb/MMBtu. These are both BACT standards.
- The 24-hour SO_2 standard of 0.10 lb/MMBtu was removed. The 30-day standards for bagasse (0.02 lb/MMBtu) and wood (0.05 lb/MMBtu) were revised to 0.10 lb/MMBtu for firing any authorized fuel. A 12-month standard of 0.06 lb/MMBtu was established. These are both BACT standards.
- The sulfuric acid mist emission (SAM) standard was removed. A revised BACT determination requires minimizing SO_2 emissions by firing low sulfur fuels to effectively limit potential SAM emissions.
- A revised BACT requires fluoride emissions to be minimized by firing biomass as the primary fuel with natural gas and very low sulfur distillate oil as supplemental fuels. The fluoride emission standards for coal and oil firing were removed.
- The beryllium standard was removed because beryllium is no longer a PSD-regulated pollutant.
- The separate lead emission standards for firing oil, bagasse, and wood were removed and replaced with a standard of 1.5×10^{-04} lb/MMBtu for firing any authorized fuel. No BACT determination was required.
- The separate mercury emission standards for firing oil, bagasse, and wood were removed and replaced with a standard of 5.43×10^{-06} lb/MMBtu for firing any authorized fuel. The permit includes conditions to reactivate the carbon injection system should mercury emission increase. No BACT determination was required.
- Changes regarding the testing requirements clarify that: compliance for CO, NOx, and SO_2 is by CEMS and not an annual stack test; either COMS data or an EPA Method 9 observation may be used to show compliance with the opacity standard; and testing requirements for arsenic, copper, and chromium emissions were removed and replaced with specific sampling, analysis, and acceptance criteria for these contaminants in the wood materials fired as biomass fuel.

The changes result in the following decreases in allowable annual emissions: CO will remain at 2012.50 tons per year; fluorides will be reduced from 21.2 to 4.03 tons per year; SAM will be reduced from 34.6 to 20.7 tons per year; and SO_2 will be reduced from 1154.3 to 345.0 tons per year. A revised ambient impact analysis was performed for CO because CEMS data indicated brief periods of elevated CO emissions. The analysis showed no adverse impacts resulting from these periods. A revised SO2 air quality analysis indicated no adverse impacts from the revised emissions standards. CEMS data indicates that the highest actual SO_2 emission rates are approximately one-fourth of the previously modeled rate for coal firing.

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

Jeffery J. Koerner — 12-20-01

Jeffery F. Koerner, P.E. (Date)
Registration Number: 49441

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 20, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Rodney Williams, Plant Manager
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, FL 33493

Re: Project No. 0990332-014-AC
Draft Permit No. PSD-FL-196M
Okeelanta Cogeneration Plant
Revised PSD Permit

Dear Mr. Williams:

Enclosed is one copy of the draft to revise air permit No. PSD-FL-196 for the existing cogeneration plant located approximately six miles south of South Bay on U.S. Highway 27 in Palm Beach County, Florida. The Department's "Technical Evaluation and Preliminary Determination", "Intent to Issue Permit", and the "Public Notice of Intent to Issue Permit" are also included.

The "Public Notice of Intent to Issue Permit" must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to Al Linero, Administrator of the New Source Review Section, at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/921-9536.

Sincerely,

for C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CHF/AAL/jfk

Enclosures

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

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

Project No. 0990332-014-AC
Draft Permit No. PSD-FL-196M
Okeelanta Cogeneration Plant
Palm Beach County, Florida

Authorized Representative:
Mr. Rodney Williams, Plant Manager

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification (copy of draft permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below. The applicant, New Hope Power Partnership, applied on January 2, 2001 to the Department for an air construction permit to revise several of the emissions standards and testing requirements as well as update the original permit for all previous changes. The cogeneration plant is located approximately six miles south of South Bay on U.S. Highway 27 in Palm Beach County, Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit modification is required to perform proposed work. The Department intends to issue this air construction permit modification based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit Modification. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting 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 Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in Section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) and (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. 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 public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S. however, any person who asked the Department 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 Department'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 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 indicate; (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 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 Department'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 Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542, F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Mediation is not available in this proceeding. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2), F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

for C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit Modification, 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 12/20/01 to the persons listed:

Mr. Rodney Williams, Plant Manager*
Mr. James Meriwether, Okeelanta
Mr. Matthew Capone, Okeelanta
Mr. David Buff, Golder Associates
Mr. James Stormer, PBCHD
Mr. Ron Blackburn, SED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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.

Victoria Gibson 12/20/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD AIR CONSTRUCTION PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Project No. 0990332-014-AC
Draft Permit PSD-FL-196M

New Hope Power Partnership – Okeelanta Cogeneration Plant

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification to the applicant, New Hope Power Partnership. The applicant operates an existing cogeneration plant that is located approximately six miles south of South Bay on U.S. Highway 27 in Palm Beach County, Florida. The Okeelanta Cogeneration Plant's authorized representative is Mr. Rodney Williams, Plant Manager, and the mailing address is 8001 U.S. Highway 27 South, South Bay, FL 33493.

Based on the applicant's requests, the draft permit includes changes to the current emissions standards and monitoring requirements for carbon monoxide, sulfur dioxide, sulfuric acid mist, beryllium, fluoride, lead, and mercury. The proposed changes represent better information now available for biomass fuel, which consists of bagasse from the adjacent sugar mill and wood material from the surrounding areas. In addition, coal will be removed as an authorized fuel.

The cogeneration boilers are considered utility steam electrical generating units. As such, the applicant predicts that future actual emissions from this project will not result in actual emissions increases for beryllium, fluorides, lead or mercury that would exceed the PSD significant emission rates. The project does represent potential significant net emissions increases of the following pollutants: carbon monoxide (486 tons per year), sulfuric acid mist (27 tons per year), and sulfur dioxide (486 tons per year). However, it is noted that potential *allowable* emissions will: remain the same for carbon monoxide; will be reduced from 35 to 21 tons per year for sulfuric acid mist; and will be reduced from 1154 to 345 tons per year for sulfur dioxide. The reductions are due to the absence of coal firing. Therefore, in accordance with Rule 62-212.400, F.A.C., the project is subject to PSD review for carbon monoxide, sulfuric acid mist, and sulfur dioxide.

The cogeneration boilers are fired primarily with wood materials and bagasse to provide steam for the adjacent sugar mill and refinery as well as generate electricity for sale to the electrical power grid. Auxiliary fuels are restricted to natural gas and very low sulfur distillate oil. The Department made the following determinations of the Best Available Control Technology (BACT) for this project. For emissions of sulfuric acid mist and sulfur dioxide, BACT was determined to be the firing of these very low sulfur fuels. For emissions of carbon monoxide, BACT was determined to be efficient combustion combined with good operating practices. The BACT standards for beryllium emissions were removed because beryllium is no longer subject to PSD review and because the primary source of beryllium was coal, which is no longer an authorized fuel. BACT for fluorides was also revised because the primary source of fluorides was coal, which is no longer an authorized fuel. The draft permit also includes several miscellaneous changes to clarify the testing and monitoring requirements and updates the permit for previous modifications.

The Department reviewed the applicant's air quality analysis preformed for carbon monoxide and sulfur dioxide. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. The maximum predicted PSD Class II sulfur dioxide (SO_2) increment consumed by all sources in the area, including this project, will be as follows:

Pollutant	Averaging Period	Maximum Predicted Impacts ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)	Percent Of Increment
SO_2	3-hour	54	512	11%
	24-hour	12	91	13%
	Annual	0	20	0%

The Everglades National Park is the nearest PSD Class I area to the project. The maximum 24-hour SO_2 increment in the Everglades National Park consumed by all sources, including this project, is predicted to be 3.5 $\mu g/m^3$, which represents 70% of the allowable PSD Class I increment of 5 $\mu g/m^3$.

The Department will issue the Final Permit with the proposed conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. 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 public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department 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 Department'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 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 indicate; (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 petitioner wishes the agency to take with respect to the agency's proposed action.

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

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection Bureau of Air Regulation New Source Review Section Suite 4, 111 S. Magnolia Drive Tallahassee, Florida 32301 Telephone: 850/488-0114	Dept. of Environmental Protection South District Office Air Resources Section 2295 Victoria Avenue, Suite 364 Fort Myers, Florida 33901-3381 Telephone: 941/332-6975	Palm Beach County Health Dept. Environmental Health and Engineering Air Pollution Control Section 901 Evernia Street West Palm Beach, Florida 33401 Telephone: 561/355-3136

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's project engineer for additional information at the address and phone numbers listed above.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATIONS

PROJECT

Project No. 0990332-014-AC
Draft Permit No. PSD-FL-196M

CO/SO_2 Modification Request
(Emissions Unit Nos. 001, 002, 003, and 004)

COUNTY

Palm Beach County

APPLICANT

New Hope Power Partnership / Okeelanta Corporation
ARMS Facility ID Nos. 0990332 / 0990005
Existing Cogeneration Plant / Sugar Mill and Refinery

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

FLORIDA

December 20, 2001

{Filename: PSD-FL-196M TEPD.doc}

1. APPLICATION INFORMATION

Applicant Name and Address

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

Authorized Representative: Mr. Rodney Williams, Plant Manager

Processing Schedule

01/02/01 Department received initial application.
01/25/01 Department requested additional information.
06/12/01 Department received additional information.
07/11/01 Department requested additional information.
08/15/01 Department received additional information; application complete.
10/23/01 Department received waiver of 90-day clock to consider revised application.
11/05/01 Department received revised application (BACT analyses for CO, SO_2, and fluorides).
12/10/01 Department received SO_2 ambient impact analysis; revised application complete.

Facility Description and Location

New Hope Power Partnership operates the Okeelanta Cogeneration Plant (OkCP) located near Highway 27, approximately 6 miles south of South Bay in Palm Beach County, Florida. The UTM coordinates are Zone 17, 524.1 km E, 2940.1 km N. The plant consists of three biomass/fossil fuel-fired steam boilers with electrical generators designed to produce up to a total of 74.9 MW of net electrical power. The plant is adjacent to an existing sugar mill and refinery owned and operated by Okeelanta Corporation. For the purposes of the Department's Prevention of Significant Deterioration (PSD) and Title V permit programs, the two plants are considered to be a single facility. The plants are located in Palm Beach County, an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The following table identifies the Standard Industrial Classification (SIC) code for each plant.

Owner/Operator	Plant	Standard Industrial Classification
New Hope Power Partnership	Okeelanta Cogeneration Plant	4911 - Electric Services
Okeelanta Corporation	Sugar Mill	2061 - Cane Sugar, Except Refining
	Sugar Refinery	2062 - Cane Sugar Refining

Regulatory Categories

HAPs: Based on available data, the facility is a major source of hazardous air pollutants (Title III).

Acid Rain: Based on the Title V air operation permit, the facility is not subject to the acid rain provisions of the Clean Air Act (Title IV).

Title V: The facility is a Title V major source of air pollution because potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. The cogeneration plant is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. As such, the facility is "major" with respect to the Prevention of Significant Deterioration (PSD) of Air Quality (Rule 62-212.400, F.A.C.) because emissions are greater than 100 tons per year for at least one regulated pollutant. Therefore, new projects require a PSD applicability review.

NSPS Sources: The cogeneration units are subject to the New Source Performance Standards in 40 CFR 60 for the fossil fuel fired steam generating units (Subpart Da) and the applicability and exemption criteria of Subpart Ea. The distillate oil tank is subject to the record keeping requirements of 40 CFR 60, Subpart Kb.

2. APPLICABLE REGULATIONS

State Regulations

This project is subject to the applicable environmental laws of Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the applicable rules and regulations of the following chapters.

Chapter	Description
62-4	Permitting Requirements
62-204	Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference
62-210	Required Permits, Public Notice and Comments, Reports, Stack Height Policy, Circumvention, Excess Emissions, Forms and Instructions,
62-212	Preconstruction Review, PSD Requirements, and BACT Determinations 62-212.300 - General Preconstruction Review Requirements 62-212.400 – Prevention of Significant Deterioration of Air Quality
62-213	Operation Permits for Major Sources of Air Pollution
62-296	Emission Limiting Standards 62-296.405 - New Fossil Fuel Steam Generators with More Than 250 Million Btu Per Hour Heat Input. 62-296.410 - Carbonaceous Fuel Burning Equipment 62-296.500 - Reasonably Available Control Technology Requirements for VOC and NOx 62-296.570 - Reasonably Available Control Technology Requirements for Major VOC and NOx Sources
62-297	Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures

Federal Regulations

This project is also subject to the applicable federal provisions regarding air quality as established by the EPA in the following sections of the Code of Federal Regulations (CFR).

Title 40, CFR	Description
Section 51.166	Requirements for State Implementation Plans, Prevention of Significant Deterioration
Section 52.21	Approval of State Implementation Plans, Prevention of Significant Deterioration
Part 60	Subpart A - General Provisions for NSPS Sources Subpart Da - NSPS for Electric Utility Steam Generating Units, Constructed After September 18, 1978 Subpart Ea - NSPS for Municipal Waste Combustors, Applicability and Exemption Requirements Subpart Kb - NSPS for Distillate Oil Storage Tank, Record Keeping Requirements Applicable Appendices

3. GENERAL PROJECT INFORMATION

History

Okeelanta Corporation owns and operates a sugar mill and refinery just south of South Bay in Palm Beach County, Florida. Sugarcane is harvested from nearby fields and transported to the mill by truck. In the mill, sugarcane is cut into small pieces and passed through a series of presses to squeeze juice from the cane. The cane juice undergoes clarification, separation, evaporation, and crystallization to produce raw, unrefined sugar. In the refinery, raw sugar is decolorized, concentrated, crystallized, dried, conditioned, screened, packaged, stored, and distributed as refined sugar. The fibrous byproduct remaining from the sugarcane is called bagasse and is burned as boiler fuel to provide steam and heating requirements for the mill and refinery. The sugar mill boilers were a primary source of air pollution due to the older, less efficient design and aging equipment.

In 1993, the Department issued a PSD permit to Flo-Energy, Inc., an affiliate of Okeelanta Corporation, to construct a cogeneration plant adjacent to the sugar mill and refinery. The project included three new biomass-fired boilers to replace the existing sugar mill boilers. "Biomass" fuels include bagasse from the adjacent sugar mill and wood materials collected from nearby counties consisting of clean dry wood, yard trimmings, land clearing debris, and other vegetative matter. The cogeneration boilers would provide high-pressure steam to generate up to 74.9 net MW of electricity and deliver low-pressure steam to meet the needs of the sugar mill and refinery. The "renewable source" electricity would be sold under contract to the Florida Power & Light Company (FPL). The cogeneration facility is currently owned and operated by New Hope Power Partnership.

The new cogeneration boilers would minimize CO and VOC emissions by high temperature, thermally efficient combustion. Urea injection would be used to reduce NOx emissions through selective non-catalytic reduction (SNCR). An electrostatic precipitator would control particulate matter emissions. Activated carbon injection would be used to reduce mercury emissions expected from coal firing. Two-thirds of the annual heat input would be provided by bagasse with the remaining one-third provided from the wood materials. Low sulfur distillate oil would be used as a startup and supplemental fuel. Although coal was originally included as an emergency fuel in order to secure financial support for the project, Flo-Energy stated that it never intended to burn coal at this facility. No coal handling facilities were ever constructed or installed. As shown in the following table, OkCP used net emissions decreases from the shutdown of the sugar mill boilers to compensate for emissions increases from the new cogeneration boilers.

Table 3A. Original PSD Applicability Analysis for Cogeneration Plant

Pollutant	Baseline[1], TPY	PSD Permit[2], TPY	Net Change, TPY	PSD SER, TPY	PSD/BACT?[3]
CO	10388.0	2012.5	-8376	100	No
NOx	888.7	862.5	-26	40	No
PM (w/fugitives)	(473.7)	172.5 (177.3)	-301 (-297)	25	No
PM_{10} (w/fugitives)	(426.3)	172.5 (174.4)	-254 (-252)	15	No
SO_2	748.3	1154.3	406	40	Yes
VOC	401.9	345.0	-57	40	No
Lead	0.280	0.17	-0.11	0.600	No
Mercury	0.026	0.0300	0.004	0.100	No
Beryllium	0.0004	0.0052	0.0048	0.0004	Yes
Fluorides	0.04	21.20	21	3	Yes
Sulfuric Acid Mist	22.40	34.60	12	7	Yes

Notes:

1. Baseline annual emissions were based on the average emissions during the most recent 2 years of operation (1990/1991 and 1991/1992 crop seasons) and the best available data.
2. The annual potential emissions are those specified in the original PSD permit [1]. Some changes have occurred since the original action. Annual emissions include potential emissions from firing low sulfur coal.
3. The original PSD permit made BACT determinations for sulfuric acid mist, sulfur dioxide, beryllium, and fluorides.

The cogeneration plant was constructed over a three-year period and commenced initial startup and commercial operation in 1996. Initial emissions performance testing was completed in 1997. However, various difficulties with fuel handling systems, the steam interconnection with the sugar mill, and a legal dispute between OkCP and Florida Power & Light delayed full operation of the plant until the 1998/1999-sugarcane crop season. The initial problems and complications lead to several revisions of the PSD air construction permit as summarized below and in Attachment A of this report.

- Clarification of the types of wood materials that could be fired.

- Several revisions to extend the "shake-down" period and allow continued operation of the sugar mill boilers.
- Authorization to perform testing while firing tire-derived fuel (expired).
- Revision of the SO_2 limits for bagasse and wood firing.
- Revision of the testing requirements for sulfuric acid mist emissions.
- Modification of the emissions standards for carbon monoxide, lead, and mercury.
- Clarification of the performance test schedule.
- Modification of the CO averaging period (24-hour to 30-day rolling average basis).
- Authorization to install particulate dust collectors prior to the electrostatic precipitators.
- Authorization to add pipeline-quality natural gas as a supplemental fuel.
- Clarification that the restriction on electrical generating capacity is "net" not "gross" generation.

Emissions Units Descriptions

The cogeneration boilers are identified by the facility as Boiler A (EU-001), Boiler B (EU-002), and Boiler C (EU-003). Each cogeneration boiler is a spreader-stoker unit. Biomass fuel enters through the fuel chute and is spread across the furnace. Small particles of biomass fuel burn in suspension above the grate. Larger materials are spread in a thin, even bed along the moving grate. Combustion occurs in three stages within a single chamber: moisture evaporation, distillation and burning of volatile matter, and burning of fixed carbon. Natural gas and distillate oil may be fired for startup or as supplemental fuel to maintain constant steam production when the biomass moisture content is excessive or the biomass feed rate is interrupted.

Capacity: Each boiler has a design heat input rate of 715 MMBtu per hour from biomass fuels, 490 MMBtu per hour from distillate oil, and 605 MMBtu per hour from natural gas. Each boiler is designed to produce 455,418 pounds per hour of high-pressure steam at 1500 psig and 975° F. The cogeneration plant is limited to an annual heat input rate of 11.5×10^{-06} MMBtu per year and an hourly net electrical generating rate of 74.9 net MW.

Allowable Fuels: The cogeneration boilers fire biomass as the primary fuel and natural gas or very low sulfur distillate oil as startup and supplemental fuels. "Biomass" includes both wood materials and bagasse. Wood materials are collected from nearby counties and consist of clean construction and demolition wood debris, dry wood, yard trash, land clearing debris, and other clean cellulose and vegetative matter. Bagasse is received from the adjacent sugar mill and consists of the fibrous, vegetative residue remaining from sugarcane after the milling process. The biomass fuel shall not contain hazardous substances, hazardous wastes, biomedical wastes, garbage, or special wastes (except wood, lumber, trees, tree remains, bagasse, cane tops and leaves, and other clean cellulose and vegetative matter). Each boiler is limited to combusting no more than 30% by weight on a calendar quarter basis of yard waste (yard trash) that is defined as a municipal solid waste (MSW) in 40 CFR 60.51a. Fossil fuel firing is limited to less than 25% of the total permitted heat input on a calendar quarter basis.

Nitrogen Oxides Controls: Each boiler is equipped with a Thermal DeNOx system that injects urea into the exhaust gas stream to reduce NOx emissions via selective non-catalytic reduction (SNCR).

Particulate Matter Controls: The primary particulate control device for each boiler is an electrostatic precipitator manufactured by Research-Cottrell. Each boiler also has a multi-tube cyclone dust collector manufactured by Barron Industries to collect large particulate matter and prevent over loading the electrostatic precipitator. All conveyors and conveyor transfer points shall be enclosed to prevent fugitive particulate matter emissions (except those associated with the stackers/reclaimers). Water sprays or chemical wetting agents and stabilizers shall be applied to stockpiles, handling equipment, and unenclosed transfer points as necessary to minimize fugitive dust emissions.

Mercury Controls: Each unit is equipped with an activated carbon injection system designed to reduce mercury emissions (primarily installed for coal firing). The activated carbon storage silos are equipped with a negative pressure system to vent exhaust to a fabric filter during operation. Exhaust from the fabric filter shall not exceed 5% opacity.

Monitoring Equipment: Each boiler is equipped with Continuous Emissions Monitoring Systems (CEMS) to monitor and record emissions of carbon monoxide, nitrogen oxides, opacity, and sulfur dioxide. The following parameters are also monitored and recorded for each unit: fuel feed rate, steam production, steam pressure, steam temperature, flue gas oxygen content and net electrical energy production.

Miscellaneous Equipment: Other equipment includes: a biomass feed system; biomass stockpiles; an ash handling and storage system; distillate oil storage tanks; boiler drums, cooling tower, diesel fire pump, steam turbine-electrical generator sets; steam condensers; cooling towers; exhaust fans; and exhaust stacks.

4. PSD PRECONSTRUCTION REVIEW

General Applicability

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as approved by the EPA in Florida's State Implementation Plan and defined in Rule 62-212.400, F.A.C. A PSD review is required only in areas currently in attainment with the National Ambient Air Quality Standard (AAQS) or areas designated as "unclassifiable" for a given pollutant. A facility is considered "major" with respect to PSD if it emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 PSD Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant and evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "significant" regulated pollutants

PSD Preconstruction Review

PSD preconstruction review consists of two parts. The first part requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to predict ambient impacts from the project; a comparison of predicted ambient impacts from the project with National Ambient Air Quality Standards and PSD Increments; an evaluation of the air quality impacts from the project upon soils, vegetation, wildlife, and visibility; and an assessment of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. The purpose of the Air Quality Analysis is to determine whether or not the proposed project will have a significant impact on PSD Class I and Class II areas and determine whether or not emissions from the project contribute significantly to, or cause a violation of, any state or federal ambient air quality standards.

The second part requires the Department to establish the Best Available Control Technology (BACT) for each pollutant emitted in excess of the PSD Significant Emission Rates. The applicant reviews current control technologies and techniques for similar projects and proposes control options and emissions standards for the project. The Department reviews the information provided by the applicant with all other available information and makes a determination of the Best Available Control Technology (BACT) for each "significant" regulated pollutant. The BACT determination must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. The Department must also give consideration to:

- Any EPA determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP).

- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determinations of any other state.
- The social and economic impacts of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

BACT determinations must result in the selection of control technologies capable of achieving at least the applicable emission standards regulated by 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP). The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention strategies. These approaches are consistent with EPA's consideration of environmental impacts and stated policy for pollution prevention.

PSD Applicability for Project

The facility is located in Palm Beach County, Florida, an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). It is an existing PSD-major source subject to the new source preconstruction review requirements. As previously discussed, the original project was subject to PSD review and BACT determinations for beryllium, fluoride, sulfuric acid mist and sulfur dioxide [1]. However, the cogeneration plant has been in commercial operation for more than two years and has established past actual emissions. The following table summarizes PSD applicability for this project based on a comparison of past actual to future actual emissions for the pollutants affected by the changes.

Table 4A. PSD Applicability - Comparison of Past Actual to Future Actual Annual Emissions

Pollutant	Past Actual Emissions, TPY [1]	Future Actual Emissions, TPY [2]	Net Change TPY	PSD SER TPY	PSD?
Carbon Monoxide (CO)	1526.07	2012.5	+ 486.4	100	Yes
Sulfur Dioxide (SO_2)	133.23	402.5	+ 269.3	40	Yes
Beryllium (Be)	0.00058	0.0009	+ 0.0003	0.0004	No [3]
Lead (Pb)	0.102	0.108	+ 0.006	0.600	No
Mercury (Hg)	0.005	0.007	+ 0.002	0.100	No
Fluorides (Fl)	0.996	1.08	+ 0.09	3	Yes [4]
Sulfuric Acid Mist (SAM)	7.99	34.6	+ 26.6	26.6	Yes

"TPY" means tons per year of emissions.

Notes:

1. CO and SO_2 emissions are based on CEMS data (April 1999 – March 2000). Sulfuric acid mist (SAM) emissions are assumed to be 6% of the SO_2 emissions, which is based on previous stack test data. Emissions of beryllium, lead, mercury, and fluorides are based on stack test data and actual annual heat input rates.
2. The applicant predicted future actual emissions of beryllium, lead, mercury, and fluorides based on operation at the full permitted heat input rate. Because past actual operation was approximately 93% of permitted capacity, the requested changes are not expected to result in significant net emissions increases for these pollutants. The applicant is allowed to predict future actual emissions because the cogeneration plant consists of electric utility steam generating units as

defined in Rule 62-210.200(12)(d), F.A.C. This was discussed in detail in the technical review for the modification of to add natural gas (Permit No. PSD-FL-196L). The applicant elected to use potential CO, SAM, and SO_2 emissions based on recent continuous monitoring data for these pollutants. Note that SAM emissions are estimated at 6% of the total SO_2 emissions.

3. Beryllium is no longer regulated as a PSD pollutant.
4. Although the requested change is not expected to result in a significant net increase in fluoride emissions, it does require a revision of the original BACT determination.

The following sections discuss the individual requests and the Department's review and preliminary determination.

5. LOW SULFUR COAL

Proposed Modification

OkCP acknowledged that coal-handling facilities were never installed and coal should be removed as an authorized fuel.

Department Review and Preliminary Determination

The Department will remove coal as an authorized fuel throughout the permit. However, the permit will note that the design of the boilers included coal as an alternate fuel source. The maximum potential emissions for each pollutant will be adjusted accordingly.

6. CARBON MONOXIDE (CO) EMISSIONS

Proposed Modification

The applicant requests a revision of the CO emissions standard when firing biomass from 0.35 lb/MMBtu based on a 30-day rolling average to 0.35 lb/MMBtu based on a 12-month rolling average. The applicant contends that a longer averaging period is necessary to account for operational variations resulting from high moisture content of the biomass fuel, which is difficult to control. The applicant believes that significant rainfall events occurring in late 1999 caused excessive moisture in the wood and bagasse stockpiles. The applicant acknowledges that numerous changes were made during the extended shakedown period because the boiler, biomass feed system, and flue gas exhaust system did not initially perform as designed. To simplify compliance, the applicant also requests that the CO emissions standards for fossil fuels be revised to a 12-month rolling average.

The applicant provided a summary of BACT emissions standards for similar existing biomass boilers from EPA's RACT/BACT/LAER clearinghouse database. The applicant notes that "good combustion practices" are the predominant control technique. The requested emissions standard is well within the range of BACT determinations for these similar projects.

Department Review and Preliminary Determination

The cogeneration plant was originally permitted in 1993, subject to PSD review [1]. However, due to a netting analysis that considered emission decreases due to the shutdown of existing sugar mill boilers, PSD review was not triggered for CO emissions. Baseline CO emissions were estimated to be 10,388 tons per year and the potential CO emissions established in the PSD permit were 2012.5 tons per year (approximately an 80% decrease in actual CO emissions). The CO emissions standard was established based on the boiler design and the vendor's guarantee. The Department notes that the original CO standard was 0.35 lb/MMBtu based on an 8-hour averaging period, which was eventually revised to 0.35 lb/MMBtu based on a 30-day rolling average.

Based on CO CEMS data, there were several excursions of the current CO emissions standard of 0.35 lb/MMBtu (30-day rolling average). However, the boilers were in compliance with the current CO emissions standard the majority of the time. A strong correlation between CO emissions and other monitored parameters (such as fuel type, biomass ratio, steam production, etc.) was not apparent from the CEMS data. The highest 8-hour CEMS readings were: Boiler A – 2.69 lb/MMBtu; Boiler B – 4.28 lb/MMBtu; and Boiler C – 1.83

lb/MMBtu. Because these values were much higher than originally evaluated, the applicant provided an ambient impact analysis that indicated no adverse impacts from the higher than expected short-term CO emissions.

The applicant provided monthly rainfall data versus monthly CO emissions data that suggests significant periods of rainfall result in elevated CO emissions occurring shortly afterwards. The applicant contends that moisture in the stockpiles accumulates after a heavy rainfall and must be driven off in the boilers. This leads to less efficient fuel combustion and higher CO emissions until the stockpiles dry. The applicant believes that even a partial cover for a 2- or 3-day supply of dry biomass would be costly and substantially restrict the current biomass handling operations (tractors, loaders, etc.).

The Department reviewed EPA's July 2001 release (Supplement G) of the 5th edition of AP-42, the federal emission factor document [3]. The supplement included a new Section 1.6 for wood residue combustion in boilers. Several new test data sets were added to previous test data due to ongoing projects such as the Industrial Combustion Coordinated Rulemaking (ICCR) workgroup. The following important changes were noted:

- The general emission factor quality rating either remained the same or improved due to the changes.
- All emissions factors are now based on heat input (lb/MMBtu).
- Data is no longer reported based on "boiler type". When required, separate emission factors are provided for "wet wood" (≥ 20% moisture) or "dry wood" (< 20% moisture).
- The previous CO emission factor was 1.51 lb/MMBtu (equivalent) for spreader stokers and had a "C" quality rating. The revised CO emission factor is 0.60 lb/MMBtu for all fuels and boiler types and has an "A" quality rating.

The emission factor revision is significant because it is representative of actual tested similar units and carries the highest quality rating (A). Although AP-42 is not appropriate for establishing a permit standard, it is suitable for estimating long-term emissions from similar units within an industry. In looking closer at the test data used to generate the revised emissions factors, the following details are noted:

Table 6A. Comparison of CO Emission Factors (AP-42) for Wet and Dry Wood

Parameter	Wet Wood, lb/MMBtu	Dry Wood, lb/MMBtu
Minimum	0.05	0.04
Maximum	2.42	2.56
Average	0.57	0.62
Standard Deviation	0.50	0.66

The above information does not appear to support the applicant's contention that higher CO emissions result from firing wet fuel. However, it is noted that the factor for wet wood was based only on 12 emissions tests, while the factor for wet wood was based on more than 60 tests. In addition, the test data does show substantial variations in emissions between tested units and individual tests. It also seems a logical assumption that a solid fuel, wet from recent rainfall, offers less efficient combustion and higher CO emissions than an identical dry fuel.

Based on the OkCP's CEMS and operational data, the actual CO emissions from the cogeneration boilers were 1526 tons per year. The actual heat input was 10,725,416 MMBtu per year. This equates to an annual CO emissions rate of 0.28 lb/MMBtu, which is approximately half of the expected rate based on AP-42 emission factor data for spreader stoker boilers. On a unit-by-unit basis, the average annual emission rates were: Boiler A – 0.25 lb/MMBtu; Boiler B – 0.30 lb/MMBtu; and Boiler C - 0.30 lb/MMBtu. These rates are approximately 15% below OkCP's requested standard of 0.35 lb/MMBtu based on a 12-month rolling average.

The Department also reviewed wood-fired boilers with PSD permits issued since 1989. Attachment B summarizes a list of facilities generated from EPA's RACT/BACT/LAER Clearinghouse with heat input greater than 200 MMBtu per hour from wood firing. The CO emissions standards range from 0.29 lb/MMBtu to 2.25 lb/MMBtu. This is within the range used to develop the revised AP-42 emission factor as well as emissions from the OkCP plant. As an example, the Michigan Department of Environmental Quality issued a recent PSD permit modification to the Grayling Generating Station L.P. (Draft Permit June 2001). This facility operates a wood-fired boiler with a capacity of 523 MMBtu per hour, which is equipped with multi-clones, an electrostatic precipitator, and selective non-catalytic reduction. The fuel, boiler capacity, and control equipment appear very similar to OkCP's cogeneration boilers. The CO emissions standard for this unit is 464 ppmvd corrected to 7% oxygen based on a 24-hour average, which is equivalent to approximately 0.50 lb/MMBtu. It is also noted that many of the wood-fired boilers listed in this table operate within a paper mill or woodworking plant. These types of facilities generate a relatively homogenous supply of wood materials for use as boiler fuel. In contrast, OkCP obtains wood materials from nearby counties in the form of clean construction and demolition wood debris, dry wood, yard trash, land clearing debris, lumber, trees, tree remains, bagasse, cane tops and leaves, and other clean cellulose and vegetative matter. The variation in biomass types can lead to wide short-term variations in fuel heating values and moisture contents.

Finally, the Department notes the following statements made by the American Gas Association in a 1987 book discussing the control of air pollution by firing or co-firing natural gas: "Water content is a major variable in wood waste utilization and here again [natural] gas assist can serve as a useful co-fuel to accommodate the particular characteristic of any load in a heat recovery incinerator. The technology of hogged wood waste burning has advanced considerably in recent years. Gas assist for drying, pyrolysis and ignition and gas afterburning for emission control purposes adds the extra degree of control needed to accommodate a large diversity of wood waste fuels." [4]

The Department concludes that the applicant's request for a longer averaging period for the CO emissions standard is reasonable given this type of operation and the final design as constructed. The biomass fuel fired in the cogeneration boilers includes a broad range of vegetative materials that may have wide fluctuations in the short-term heating value and moisture content, which can result in higher short-term CO emissions. Substantial rainfall events appear to increase actual CO emissions. Therefore, the Department specifies the following draft BACT standards based on good combustion practices.

- The current CO standard of 0.35 lb/MMBtu based on a 30-day rolling average will be revised to 0.50 lb/MMBtu based on a 30-day rolling average.
- A CO standard of 0.35 lb/MMBtu based on a 12-month rolling average will be established.

In addition, all references to coal firing will be removed. The 12-month rolling average ensures that the cogeneration boilers, as constructed, remain capable of complying with the original design specification on a long-term basis. The increased 30-day rolling average provides operational flexibility in consideration of the varying fuel qualities and sets an upper limit. Compliance continues to be by CEMS. The draft permit will also include additional requirements regarding good combustion practices such as monitoring the flue gas oxygen content to optimize air/fuel ratio parameters, preventing tramp air intrusion into the boilers, mixing biomass to provide a homogeneous fuel blend, or supplemental fuel firing to enhance combustion.

The Department did not perform a rigorous review of available control equipment for this project. The highest ranking add-on control alternative would likely be a catalytic oxidation system. However, a biomass boiler may not be an appropriate application for this control option because of the relatively high particulate matter loading and flue gas moisture content, which can lead to fouling of the catalyst. Rather, the Department relied largely on the information regarding similar biomass boilers identified in the RACT/BACT/LAER clearinghouse. No add-on controls were specified for these types of units. The proposed emission standards appear to be well within the range identified as BACT for biomass boilers. Some consideration was also given to the wide range of biomass fuel being fired at this facility compared to similar facilities firing biomass from a single source. The revised standard does not result in increased allowable annual emissions.

7. SULFUR DIOXIDE (SO2) EMISSIONS

Proposed Modification

The applicant requests the following revisions of the SO_2 biomass standards: from 0.10 lb/MMBtu to 0.20 lb/MMBtu based on a 24-hour average; from 0.02 lb/MMBtu (bagasse) and 0.05 lb/MMBtu (wood) to 0.10 lb/MMBtu (biomass) based on a 30-day rolling average; and a long-term SO_2 standard of 0.07 lb/MMBtu based on a 12-month rolling average. The applicant contends that these changes are necessary due to the higher than expected SO_2 emissions when firing biomass and offers two possible reasons. First, mechanical dust collectors were installed to remove large particles and prevent overloading the electrostatic precipitators (ESPs). The applicant believes that SO_2 in the flue gas is partially absorbed by large fly ash particles, which are typically alkaline in nature. Removing these larger particles immediately after the boiler air pre-heater allows less time for the reaction between SO_2 emissions and the alkaline particles to take place. Secondly, the applicant contends that actual analyses of biomass samples over the last several years indicate a greater variability in the sulfur content (particularly wood) than previously believed. The applicant notes that, based on their requests, annual potential SO_2 emissions would be reduced from 1154 to 402.5 tons per year. In addition, the applicant also requests revisions of the long-term biomass mix from 34% wood/66% bagasse to 50% wood/50% bagasse.

The applicant provided a summary of BACT emissions standards for similar existing biomass boilers from EPA's RACT/BACT/LAER clearinghouse database. "Low sulfur fuels" are typically specified for biomass boilers, although a few projects have required flue gas desulfurization equipment. SO_2 BACT standards ranged from 0.083 to 0.46 lb/MMBtu with the highest standard for a boiler firing a combination of bark and sludge. Paper mill sludge can have a much higher sulfur content than bark alone. Many facilities fuel units with wood materials from nearby cabinet shops or related activities. This provides a much more homogeneous and controllable fuel supply than that of OkCP. The applicant identifies technically feasible add-on control equipment such as wet and dry flue gas desulfurization. However, these systems result in waste disposal problems and would likely be cost prohibitive for retrofit to the existing units, particularly considering that potential SO_2 emissions are being reduced form 1154 to 402 tons per year as a result of this project. The applicant believes that low sulfur fuels continue to reflect BACT for these biomass boilers as evidenced by the RACT/BACT/LAER clearinghouse data.

Department Review and Preliminary Determination

The original project was subject to PSD review for SO_2 emissions; however this was because coal was included as a "reliable" backup fuel due to financial concerns. For the initial project, the Department determined that firing low sulfur fuels, restricted fossil fuel firing, and an annual SO_2 emissions limit represented the Best Available Control Technology (BACT) for SO_2 emissions. The applicant's new requests would not affect the firing of "low sulfur" fuels. In fact, coal will be removed as an authorized fuel and fossil fuel firing (natural gas and distillate oil) will continue to be limited to less than 25% of the heat input for each calendar quarter. Allowable annual SO_2 emissions would be greatly reduced.

In reviewing the original application, assumptions related to biomass fuel sulfur content turned out to be poor. The following table summarizes the biomass fuel sulfur content.

Table 7A. Biomass Fuel Sulfur

Information Source	Wood, % by wt. dry	Bagasse, % by wt. dry
Original PSD Application [1]	0.009%, avg.	0.009%, avg.
OkCP, Actual Samples	0.02%, low 0.07%, avg. 0.27%, high	0.02%, low 0.03%, avg. 0.05%, high
Babcock and Wilcox [2]	0.1% (Pine and Hardwoods)	No Data
AP-42, Appendix A	Negligible	"Low Levels"

As shown, these fuels typically have very low levels of sulfur. However, actual sampling data by OkCP shows a wide variation of fuel sulfur for wood and some variation for bagasse. The SO_2 emission factors corresponding to the average actual fuel sulfur would be 0.31 lb/MMBtu for wood and 0.16 lb/MMBtu for bagasse. Actual annual monitored SO_2 emissions (0.025 lb/MMBtu), suggest that only 10% of the potential emissions are exiting the exhaust stack. This could be due to a number of reasons, including: a portion of the available fuel sulfur is not oxidized and remains in the ash; absorption of SO_2 onto alkaline fly ash particles in the exhaust gas, which are removed in the ESP; or a combination of both. There is insufficient information to determine whether or not installation of the mechanical dust collectors affected any reduction mechanism.

EPA revised Section 1.6 (Supplement G to the 5th edition) for wood residue combustion in boilers in July of 2001 [3]. The Department notes the following important changes regarding SO_2 emission rates:

- The old SO_2 emission factor was 0.008 lb/MMBtu (equivalent) for wood-fired boilers with a "B" rating. The revised SO_2 emission factor is 0.025 lb/MMBtu for all fuels and boiler types with an "A" rating.
- Based on the AP-42 test data used to generate the emissions factors, the average SO_2 emission rate for all tested spreader-stoker boilers firing wet wood is 0.032 lb/MMBtu.

This revision is significant because it reflects an increase of more than three times the previous published value. A review of the supporting test data shows that the measured SO_2 emission rates ranged from 0.001 to 0.13 lb/MMBtu. In addition, the tested units did not employ equipment specifically designed to remove SO_2 emissions, which means that the tested emission rates should be a function of the wood sulfur content. This suggests a wide variation in the wood sulfur contents fired during the tests, which is reflected in the new emission factor.

Again, Attachment B summarizes a list of facilities generated from EPA's RACT/BACT/LAER Clearinghouse for similar boilers with heat inputs greater than 200 MMBtu per hour from wood-firing that were permitted after 1989. The SO_2 emissions standards range from 0.008 to 0.30 lb/MMBtu, with an average of 0.06 lb/MMBtu. Many of the averaging periods are on a long-term basis. One similar facility (Scott Paper Company) has a 365-day rolling average.

Based on CEMS data, the actual annual SO_2 emissions from the cogeneration boilers averaged 133.23 tons per year. The actual heat input was 10,725,416 MMBtu per year, which is 93% of the permitted annual capacity. This equates to an annualized emissions rate of 0.025 lb/MMBtu, which correlates well with the revised AP-42 emissions factor of 0.025 lb/MMBtu. Individually, the calculated annual emissions rates would be: Boiler A – 0.025 lb/MMBtu; Boiler B - 0.024 lb/MMBtu; and Boiler C - 0.026 lb/MMBtu.

To evaluate the applicant's belief that flue gas desulfurization remains cost prohibitive for the biomass boilers, the Department estimated costs for a lime spray dryer system, which is typically less expensive that wet scrubbers or other dry injection techniques with similar control efficiencies. This technology is well known and utilized at numerous power plants around the country. Based on the original vendor quotes in the 1993 permit application, control costs were corrected to reflect less "contingencies" and lower operational costs than originally assumed. Examples of lower operating costs include reducing hydrated lime and solid waste disposal costs in proportion to the amount of SO_2 available for control. In addition, capital cost recovery was based on 7% interest and a 15-year equipment life. Lime spray dryer systems for the project were estimated to result in $7,130,500 in capital costs and $1,427,700 in annual operating costs. Total annualized costs for a lime spray dryer system were estimated to be $2,210,600 per year. Based on an uncontrolled emission rate of 0.07 lb/MMBtu, the cost effectiveness would be $5772 per ton of SO_2 removed (383 tons of SO_2 removed with a control efficiency of 95%). Based on an uncontrolled emission rate of 0.06 lb/MMBtu, the cost effectiveness would be $8068 per ton of SO_2 removed (274 tons of SO_2 removed with a control efficiency of 95%).

Because equipment costs can change substantially over eight years, an additional estimate was performed based on information available from the power plant industry [5, 6, 7]. Based on an industry factor of $100 per installed kW, the total capital costs were estimated to be $7,500,000. Based on an industry factor of $4 per kW-yr, fixed annual operating and maintenance costs were estimated to be $300,000 per year. Based on an industry factor of $2.24 per MW-hr, 90% capacity, and 61% utilization, the variable annual operating and maintenance costs were estimated to be $814, 000 per year. Based on a 7% interest rate and 15-year equipment life, the annualized control costs were estimated to be $1,937,500 per year. Based on an uncontrolled emission rate of 0.06 lb/MMBtu, the cost effectiveness would be $7071 per ton of SO_2 removed (274 tons of SO_2 removed with a control efficiency of 95%). This represents a less than 15% difference with the previous estimate and provides some reassurance.

However, actual annual SO_2 emissions have been relatively low. As previously mentioned, the actual annual SO_2 emissions from this plant were reported as 133 tons per year. Assuming annualized control costs of $2,074,050 (average of two examples) and a control efficiency of 95%, the cost effectiveness would approach $16,500 per ton of SO_2 removed. This would clearly be cost prohibitive.

The Department concludes that the applicant's request for revised SO_2 emissions standards is reasonable based on the available information, which indicates that the fuel sulfur content of biomass is higher than originally proposed and much more variable. Bagasse is about three times higher and wood materials nearly seven times higher than originally expected. The SO_2 emissions are directly a function of the fuel sulfur content, but are difficult to minimize on a short-term basis because of fuel sulfur variation and the unqualified SO_2 removal mechanism. The retrofit of add-on flue gas desulfurization equipment does not appear appropriate for the existing units nor the requested modification. Therefore, the Department establishes the following draft BACT standards based on the firing of low sulfur fuels.

- The current 24-hour SO_2 standard is revised to 0.20 lb/MMBtu when firing any authorized fuel.
- The 30-day rolling SO_2 standard will be revised to 0.10 lb/MMBtu when firing any authorized fuel. This is consistent with the 30-day averaging period specified in NSPS Subpart Da and represents a much lower limit than the NSPS (0.60 lb/MMBtu for solid fuel and 0.20 lb/MMBtu for gas and oil firing).
- An annual SO_2 standard will be established at 0.06 lb/MMBtu based on a 12-month rolling average when firing any fuel.

All references to coal firing will be removed. The 30-day rolling standard provides the operational flexibility requested due to fuel sulfur variability while maintaining low SO_2 emissions. The 12-month standard is consistent with past operation, while giving consideration to the following: absence of coal firing; higher fuel sulfur contents for biomass than previously believed; an increased wood/bagasse fuel ratio; the addition of natural gas firing; and the quarterly heat input limit on fossil fuel firing. In addition, note "c" in Permit Condition No. 20 will be deleted because the permitting action satisfies this requirement. This note allows revision of the 30-day rolling average SO_2 emissions standard subsequent to initial compliance testing.

8. SULFURIC ACID MIST (SAM) EMISSIONS

Proposed Modification

The applicant requests revision of the sulfuric acid mist emission standard for biomass firing from 0.003 to 0.012 lb/MMBtu based on an average of three 1-hour test runs. The basis for the request is that sulfuric acid mist emissions were originally estimated based on SO_2 emissions for which an increase in the emission limit has also been requested.

Department Review and Preliminary Determination

The initial tests conducted for sulfuric acid mist indicate an actual average emission rate of 0.0015 lb/MMBtu. This is approximately 6% of the annual actual SO_2 emission rate of 0.025 lb/MMBtu. The Department notes that the original PSD permit did not include a BACT determination for sulfuric acid mist emissions, as was required [1]. Limiting SO_2 emissions effectively limits potential emissions of sulfuric acid mist. Therefore, the Department makes a draft BACT determination that sulfuric acid mist emissions are minimized by the use of low sulfur fuels and restricted fossil fuel firing. The revised permit will note that sulfuric acid mist emissions are estimated to be approximately 6% of the SO_2 emissions based on CEMS data for purposes of reporting annual emissions.

9. BERYLLIUM EMISSIONS

Proposed Modification

The applicant requests removal of the beryllium emissions standards and testing requirements for coal and oil firing. The applicant contends that these limitations were the result of coal firing, which accounted for the majority the total emissions. Because coal firing is being removed from the permit, the applicant requests removal of these standards.

Department Review and Preliminary Determination

In the original PSD permit, the Department determined BACT to be the firing of low sulfur coal and distillate oil, the restricted use of these fuels, and the installation of an electrostatic precipitator to capture particulate matter emissions, which would contain beryllium [1]. The determination stated that the primary sources of beryllium were fossil fuels and specified limits for coal and oil firing. The original application considered beryllium emissions to be negligible when firing biomass fuels and the permit contains no emission standards for biomass firing. The beryllium standard (5.9×10^{-06} lb/MMBtu) for coal firing is nearly 17 times higher than the standard for oil firing (3.5×10^{-07} lb/MMBtu). Actual stack test data indicates that beryllium emissions when firing bagasse are below the detectable level of the test method. Limited test data when firing wood material indicates beryllium emissions of 2.23×10^{-07} lb/MMBtu, which is on the order of magnitude of the oil-firing standard. However, several of the test runs reported emission rates below the detectable level of the test method.

Beryllium is no longer a PSD regulated pollutant (see Table 62-212.400-2, F.A.C.) and coal, the highest potential source of beryllium, will be removed as an allowable fuel. Therefore, the beryllium emission standards and testing requirements for coal and oil firing will be removed. Beryllium emissions continue to be minimized by the firing of biomass fuels and very low sulfur distillate oil, which contain only trace amounts of beryllium. In addition, the beryllium is generally emitted as a particulate emission, which continues to be filtered out with the existing electrostatic precipitator (ESP). This determination results in the regulation of beryllium consistent with other trace metals for similar combustion sources.

10. FLUORIDE EMISSIONS

Proposed Modification

The applicant requests removal of the fluoride emission standards and testing requirements for both coal and oil firing. The applicant contends that these limitations were the result of coal firing, which accounted for nearly 99% of the total emissions. Because coal firing is being removed from the permit, the applicant requests removal of these standards. If a fluoride limit for biomass firing is required by the Department, the applicant requests a standard of 7.0×10^{-04} lb/MMBtu. The applicant notes that this is the highest tested rate for bagasse and wood firing from a single boiler and would likely overstate the annual emissions. However, the applicant believes that such a higher limit is necessary due to the potential fuel variability.

Department Review and Preliminary Determination

In the original PSD permit, the Department determined BACT to be the firing of low sulfur coal and the use of an ESP to capture particulate matter emissions, which contained fluorides [1]. The determination stated that the primary source of fluorides was low sulfur coal, but specifies limits for both pollutants when firing coal and distillate oil. The original application considered fluoride emissions to be negligible when firing biomass fuels and the permit contains no emission standards for biomass firing.

The fluoride standard (2.4×10^{-02} lb/MMBtu) for coal firing is several orders of magnitude higher than the standard for oil firing (6.3×10^{-06} lb/MMBtu). Actual stack test data indicates that fluoride emissions when firing bagasse are 2.24×10^{-04} lb/MMBtu and when firing wood material are 1.46×10^{-04} lb/MMBtu, which is higher than the limit for oil firing. Fluoride would generally be emitted in gaseous form as hydrogen fluoride, which would not be controlled by an electrostatic precipitator. Given the maximum emissions rate of 7.0×10^{-04} lb/MMBtu requested by the applicant, maximum annual fluoride emissions would only be 4.03 tons per year. At this level, the Department believes that add-on controls would be cost prohibitive. Therefore, the

Department makes the following draft BACT determination.

- All references to coal firing will be removed.
- The fluoride emission standard for oil firing will be removed.
- Fluoride emissions shall be minimized by firing biomass as the primary fuel with natural gas and very low sulfur distillate oil as supplemental fuels.

The firing of biomass, natural gas, and distillate oil (which contain little or no fluorides), represents BACT for the biomass boilers. The Department believes that enough stack testing has been performed to determine a reliable emission factor. Uncontrolled fluoride emissions are typically very low for the fuels authorized in the draft permit.

11. LEAD EMISSIONS

Proposed Modification

The applicant requests revision of the lead emissions standard from 2.5×10^{-05} to 1.6×10^{-04} lb/MMBtu for bagasse firing, which would be the same as the standard for firing wood material. This change would result in a single limit for "biomass" fuels and simplify the testing requirements. The applicant also requests that the emissions standards be "bubbled" over the three cogeneration boilers.

Department Review and Preliminary Determination

Based on actual stack tests, lead emissions range from 3.4×10^{-06} to 2.0×10^{-05} lb/MMBtu for bagasse firing. (A single high value of 8.4×10^{-05} lb/MMBtu for wood firing occurred with high particulate matter emissions prior to installation of the mechanical dust collectors.) The test results show high variability between individual units and tests. The original PSD preconstruction review was based on a bagasse emission rate of 7.7×10^{-04} lb/MMBtu for the existing mill boilers. Based on this emission rate, an assumed particulate removal efficiency of 90% for the existing wet scrubbers, and a designed particulate removal efficiency of 98% for the for the ESP/dust collectors, the estimated controlled emission rate for bagasse firing from the cogeneration boilers would be 1.5×10^{-04} lb/MMBtu. This is similar to the requested new emission standard.

The current lead emissions standard for wood firing is 1.6×10^{-04} lb/MMBtu. Based on actual stack tests, lead emissions from wood firing ranged from 7.97×10^{-06} to 8.4×10^{-05} lb/MMBtu, which is nearly 50% of the current standard for the highest rate. The Department also notes that the original project did not trigger PSD review for lead emissions [1]. According to the original PSD review, the baseline lead emissions are 0.280 tons per year and the potential lead emissions specified in the original PSD permit were 0.17 tons per year. This resulted in an expected net emissions decrease of 0.11 tons per year and avoided PSD review. Based on this information, the Department makes the following preliminary determination.

- All references to coal firing will be removed.
- The lead emission standards will be revised to 1.5×10^{-04} lb/MMBtu for firing any authorized fuel.

The revised standards continue to ensure that the project does not trigger PSD review for lead. The changes do not relax any requirements for existing control equipment.

12. MERCURY EMISSIONS

Proposed Modification

The applicant requests revision of the mercury emissions standard for wood firing from 4.0×10^{-06} lb/MMBtu to 5.43 E^{-06} lb/MMBtu and that the standards be "bubbled" over the three cogeneration boilers. This would be consistent with the mercury limit when firing bagasse, results in a single limit for "biomass" fuels, and simplifies the testing requirements. The applicant also requests that the requirement to operate the activated carbon injection system be removed due to compliance with the existing mercury emission limits without carbon injection. The applicant would retain the existing carbon injection system in place in case operation in the future warrants reactivation of the system.

Department Review and Preliminary Determination

Based on nine initial test runs conducted in 1996 when injecting activated carbon, the estimated mercury emission rate averaged: 3.05 x 10^{-06} lb/MMBtu with an injection rate of 7 lb/hour, 2.06 x 10^{-06} lb/MMBtu with an injection rate of 16 lb/hour, and 2.84 x 10^{-06} lb/MMBtu with an injection rate of 23 lb/hour. The tests were not conclusive with regard to effective mercury control by carbon injection, but did indicate low overall emissions.

Based on nine test runs for bagasse firing conducted in 1999 without activated carbon injection, the mercury emission rate ranged 0.348 x 10^{-06} lb/MMBtu to 0.616 x 10^{-06} lb/MMBtu. Based on nine test runs for wood firing conducted in 1999 without activated carbon injection, the average mercury emission rate ranged from 1.02 x 10^{-06} lb/MMBtu to 3.28 x 10^{-06} lb/MMBtu. In fact, only two of the eighteen test runs when firing either fuel were above the *lowest* estimated average emission rate when injecting any carbon. The similar emission rates with and without carbon injection are likely the result of low uncontrolled mercury emissions combined with an already high carbon content in the flue gas that results from combusting biomass. Because the units could comply with the mercury emission limits without injecting carbon, these systems are not currently in operation.

Mercury emissions when firing bagasse averaged 0.64 x 10^{-06} lb/MMBtu over the last three years, which is approximately 10% of the requested standard. The highest individual test for firing bagasse indicated a mercury emission rate of 1.41 x 10^{-06} lb/MMBtu. Mercury emissions when firing wood materials averaged 1.15 x 10^{-06} lb/MMBtu over the last three years, which is approximately 20% of the requested standard. The highest individual test for wood firing indicated a mercury emission rate of 3.6 x 10^{-06} lb/MMBtu.

Based on the original PSD application, mercury emissions when firing wood were expected to be about 19 times *lower* than when firing bagasse. Actual tests indicate that mercury emissions when firing wood are nearly two times *higher* than when firing bagasse. The mercury limit in original permit was 8.4 x 10^{-06} lb/MMBtu for coal firing. The emission factors for both bagasse and oil firing were based on a 30% reduction with the activated carbon injection system. However, each boiler has been able to comply with the mercury limits without injecting activated carbon. In addition, original permit Condition No. 25 of the permit states, "The [fuel management] plan shall include mercury emission factors based on stack testing and baseline estimates for the existing Okeelanta facility." Note that mercury emissions were not subject to an initial BACT determination [1].

Based on the above information, the Department makes the following preliminary determination:

- All references to coal firing will be removed.
- The mercury emission standards will be revised to 5.4 x 10^{-06} lb/MMBtu for firing any authorized fuel.
- If two or more cogeneration boilers exceed the mercury emission limit, the draft permit requires reactivation of the carbon injection system and specifies actions necessary to identify an effective minimum carbon injection rate to reduce mercury emissions.

The potential mercury emissions from the entire cogeneration plant are approximately 62 pounds per year, which is well below the PSD significant emissions rate of 200 pounds per year. Annual stack testing is required to determine compliance.

13. OTHER MISCELLANEOUS CHANGES

Proposed Modification

The applicant also requests the following additional changes: remove annual testing requirements for CO, NOx, SO_2, and visible emissions because compliance for these pollutants is based on continuous monitoring systems; remove the annual testing requirements for beryllium and fluorides because coal firing is being removed; remove the annual testing requirements for arsenic, copper, and chromium be removed because there are no related emissions "standards" for these pollutants; remove the requirement to conduct PM_{10} testing because the PM and PM10 standards are identical; specify that EPA Method 29 may also be used for testing lead and mercury emissions; revise the conditions covering startup, shutdown and malfunctions to allow for up to six hours for a cold startup, three hours for a warm startup, two hours for a shutdown, and two hours for a malfunction; and up to four 6-minute periods of opacity in excess of the standard due to soot blowing.

Department Review and Preliminary Determination

The Department agrees with the applicant's requests, subject to the following conditions:

- All of the requirements regarding coal firing will be removed.
- The permit will be revised to make it clear that compliance with the CO, NOx, and SO_2 emissions standards will be based on CEMS data.
- The permit will be revised to make it clear that the permittee would demonstrate compliance with the opacity limit based on COMS data, but that EPA Method 9 observations could also be used. This provides a method for the Compliance Authority to verify visible emissions as well as an alternate method in case of a monitor malfunction.
- The testing requirements for arsenic, copper, and chromium emissions will be removed because there are no emissions standards for these pollutants. However, the permit does contain acceptance criteria for these contaminants in the wood materials to be fired as fuel. The draft permit will include more specific requirements for sampling and analyzing the as-fired biomass fuel.
- Based on limited test data, PM_{10} emissions appear to be approximately 70% of total filterable particulate emissions. Because the emissions standard for PM_{10} emissions is the same as the filterable particulate matter emissions, the requirement to conduct PM_{10} tests will be removed. A requirement will be added to report all particulate matter emissions as PM_{10}.
- EPA Method 29, the EPA-approved test method for multiple metals, will be added to the allowable test methods for lead and mercury in addition to EPA Methods 12 and 101A, respectively.
- The conditions covering periods of startup, shutdown and malfunction will be revised. Definitions were added for startup, warm startup, cold startup, shutdown, and malfunction. For CO and NOx emissions, the following periods of data may be excluded in a 24-hour period from the compliance determinations: six hours due to cold startup, three hours due to warm startup, two hours due to shutdown, and two hours due to malfunction. In addition, the amount of excluded data was limited to no more than 183 hours in any calendar quarter (an average of two hours per day). No SO_2 CEMS data may be excluded.
- The conditions regarding opacity will be revised as follows: natural gas or distillate oil shall be fired during startup prior to energizing the ESP; the ESP shall be placed on line once the recommended operational temperature has been maintained; the ESP shall be on line and functioning properly before firing any biomass; the opacity standard does not apply when the ESP is offline during startup or shutdown; up to two hours of COMS data in a 24-hour period may be excluded due to malfunction if documented within one working day of occurrence. No COMS data may be excluded due to soot blowing because this conflicts with the NSPS requirements.

14. AIR QUALITY MODELING

Project Summary

The applicant predicts that the proposed project could result in increased actual emissions of CO and SO_2 at levels exceeding the PSD significant emission rates. SO_2 is a criteria pollutant with defined national and state ambient air quality standards (AAQS), PSD Class I/II significant impact levels, and PSD Class I/II increments. CO is a criteria pollutant with only AAQS and PSD Class II significant impact levels defined for it. The applicant's initial impact analysis predicted that ambient concentrations of CO and SO_2 could be above the significant impact levels. Therefore, the following additional analyses were required.

- An AAQS analysis for CO and SO_2;
- A PSD Class I/II increment analysis for SO_2;
- An analysis of impacts on soils, vegetation, visibility and of growth-related air quality modeling impacts.

Based on the applicant's initial screening analysis, the predicted ambient CO and SO_2 concentrations did not exceed the de minimis ambient impacts listed in Table 62-212.400-4, F.A.C. Therefore, preconstruction ambient monitoring is not required and existing representative ambient monitoring data was used in the additional air quality analyses. The applicant's AAQS analysis predicted ambient levels of CO and SO_2 well below the Ambient Air Quality Standards. The applicant's Class II increment analysis for SO_2 predicted ambient concentrations well below the increments defined for PSD Class II areas in the vicinity of the project. The nearest Class I area is the Everglades National Park which is located approximately 92 km south of the project site. The applicant's Class I increment analysis for SO_2 predicted ambient concentrations below the PSD Class I increments defined for national parks and wildlife areas.

Based on the required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the proposed draft permit conditions, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A discussion of the required analyses follows.

ISCST3 Air Dispersion Model

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the predicted ambient pollutant impacts from the proposed project and other existing major facilities. The model determines ground-level ambient concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project will not exceed the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) station at West Palm Beach, Florida. The 5-year period of meteorological data was from 1987 through 1991. This NWS station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

CALPUFF Air Dispersion Model

A long-range transport model was required to evaluate impacts to the Everglades National Park (ENP) because this designated Class I area is greater than 50 km from the proposed project. The applicant used the California Puff (CALPUFF) dispersion model to evaluate potential impacts to the nearest PSD Class I area with regard to the significant impact analysis, PSD increment analysis, and regional haze. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. The model predicts ambient concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

Meteorological data was processed by the California Meteorological (CALMET) model for use in the

CALPUFF air dispersion model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. For this project, the CALMET model produced a rectangular modeling domain that is approximately 470 km (N-S) by 450 km (E-W). The southwest corner is the origin of the modeling domain and is located at 23.8° north latitude and 83.5° west longitude. This modeling domain was produced by using 1990 meteorological data from 3 sea surface, 3 upper air, 8 land surface, and 23 precipitation stations located throughout Florida and adjacent waters.

Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions changes. If this modeling shows significant impacts, further modeling is required to determine the project's impacts on the AAQS or PSD increments. For determining these impacts a combination of polar and rectangular receptors were located along the fenced and/or controlled access property line and out to 30 km from the cogeneration boilers, which are located in a PSD Class II area. In addition, 126 discrete receptors were located in the ENP, which is designated as a PSD Class I area. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether or not the project could result in a significant impact to a PSD Class II area (area in the vicinity of the facility) or a PSD Class I area (designated national parks or wildlife areas). If the maximum predicted impact from a project is less than the corresponding significant impact level, the project is said to have an insignificant impact and further analysis is not required. If a project is determined to have a significant impact, a full impact analysis is required to evaluate not only the impact from the project, but also other nearby major sources and area background concentrations. Ambient impacts predicted by the full impact analysis must meet all applicable AAQS and PSD increments for each pollutant exceeding the PSD significant impact level.

Using the ISCST3 air dispersion model described above, the applicant performed a PSD Class II significant impact analysis for CO and SO_2. The following table summarizes the results of this modeling, including the predicted radius of significant impact, if applicable.

Table 14A. Results of Significant Impact Analysis for PSD Class II Areas (Vicinity of Project)

Pollutant	Averaging Period	Maximum Predicted Impacts ($\mu g/m^3$)	Significant Impact Levels ($\mu g/m^3$)	Significant Impact?	Radius of Significant Impact (km)
CO	1-hr	2580	2000	Yes	6
	8-hr	150	500	No	
SO_2	3-hour	13	25	No	
	24-hour	9	5	Yes	10
	Annual	0.2	1	No	

Using the CALPUFF dispersion model described above, the applicant performed a PSD Class I significant impact analysis for SO_2. The following summary table shows the results of this modeling.

Table 14B. Results of Significant Impact Analysis for PSD Class I Areas (ENP)

Pollutant	Averaging Period	Maximum Predicted Impacts ($\mu g/m^3$)	EPA Significant Impact Levels ($\mu g/m^3$)	Significant Impact?
SO_2	3-hour	0.6	1.0	No
	24-hour	0.3	0.2	Yes
	Annual	0.0	0.1	No

As shown in the tables, the project is significant for both CO and SO_2. Therefore, the following additional analyses are required: an AAQS analysis for CO and SO_2; a PSD Class II increment analysis for SO_2; and a PSD Class I increment analysis for SO_2.

Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless exempt or otherwise satisfied by existing data. The preconstruction ambient monitoring data is used to establish an existing ambient background concentration, which can be used further air quality modeling analyses. Based on air quality modeling, the project may be exempt from the preconstruction monitoring if the resulting maximum ambient impact level is less than the de minimis concentration listed in Table 62-212.400-3, F.A.C. Also, the Department may approve existing ambient monitoring data that is believed to be representative of the area.

Using the ISCST3 air dispersion model, the applicant performed an air quality analysis to determine predicted impacts for comparison to the preconstruction monitoring de minimis impact levels. The following table shows that the predicted impacts from the project are less than the corresponding de minimis levels; therefore, preconstruction ambient air quality monitoring is not required for any pollutant.

Table 14C. Maximum Predicted Air Quality Impacts Compared to De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	De Minimis Level ($\mu g/m^3$)	Impact Greater Than De Minimis?
CO	8-hour	150	575	No
SO_2	24-hour	9	13	No

AAQS Analysis

Using the ISCST3 model, the applicant performed a full impact modeling analysis to determine impacts of all sources in the vicinity of the project for comparison to the Ambient Air Quality Standards (AAQS). Receptors were placed along the property boundary and out to 10 km for $SO_2$and 6 km for CO (each pollutant's respective radius of significant impact). Background concentrations were established from data collected at representative $SO_2$and CO monitors located in the area. These background concentrations take into account all sources of a particular pollutant that are not explicitly modeled. Because five years of data are used in the modeling analysis, the highest-second-high (HSH) short-term predicted concentrations were compared to the corresponding AAQS. For an annual average, the highest predicted yearly average was compared to the standard. The following table summarizes the results of this analysis.

Table 14D. Results of AAQS Impact Analysis

Pollutant	Averaging Period	Modeled Sources ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	Florida AAQS ($\mu g/m^3$)	Total Impact Greater Than AAQS?
CO	1-hr	3100	4500	7500	40,000	No
	8-hr	800	3000	3800	10,000	No
SO_2	3-hour	248	201	47	1300	No
	24-hour	76	63	13	260	No
	Annual	16	11	5	60	No

As shown, the predicted maximum ambient concentrations are well below the AAQS.

SO_2 Increment Analysis for PSD Class II Area

The SO_2 PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of SO_2 from a baseline concentration, which was established in 1977. Receptors were placed along the property boundary and out to 10 km. Using the ISCST3 air dispersion model, the applicant performed a full impact modeling analysis to evaluate the SO_2 impacts to the area in the vicinity of the project, which is designated as a PSD Class II area. The emission values that are input into the model for predicting increment consumption are based on maximum potential emissions from increment-consuming facility sources and all other increment-consuming sources in the vicinity of the facility. Because five years of data are used in modeling analysis, the highest-second-high (HSH) short-term predicted concentration was compared with the corresponding PSD increment. For an annual average, the highest predicted yearly average was compared to the standard. The following table summarizes the results of this analysis.

Table 14E. Results of SO_2 Increment Analysis for Class II Areas (Vicinity of Project)

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)	Impact Greater Than Allowable Increment?
SO_2	3-hour	54	512	No
	24-hour	12	91	No
	Annual	0	20	No

As shown, the predicted maximum ambient impacts are well below the PSD increments defined for the Class II area in the vicinity of the project.

SO_2 Increment Analysis for PSD Class I Area

Using the CALPUFF air dispersion model, the applicant performed a full impact modeling analysis to evaluate 24-hour average SO_2 impacts to the Everglades National Park, which is the nearest PSD Class I area. The highest short-term predicted concentration was compared to the respective PSD increment. The following table summarizes the results of this analysis.

Table 14F. Results of SO_2 Increment Analysis for Nearest PSD Class I Area (Everglades National Park)

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)
SO_2	24-hour	3.5	5

As shown, the predicted maximum ambient impact is well below the PSD increment defined for the Class I area.

Additional Impacts Analysis: Soils, Vegetation, Wildlife, and Visibility

The maximum ambient CO and SO_2 concentrations due to project impacts and other nearby sources are predicted to be well below the corresponding Ambient Air Quality Standards (AAQS). The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area.

Using the CALPUFF air dispersion model, the applicant performed a regional haze analysis for the Everglades National Park PSD Class I area. The model predicted a 24-hour visibility degradation of 1.38% due to the project, which is below the criteria level of 5%. The conclusion is that the project will not adversely impact the background visibility at the Everglades National Park. No significant impacts to the air quality related values (AQRV) in the Everglades National Park are expected due to this project.

Air Quality Impacts Related to Growth Due to the Project

There will be no growth associated with this project because it involves the modification of an existing operation.

15. PRELIMINARY DETERMINATION

Although not required, the Department offers the following information to show that the proposed changes do not adversely affect the original PSD applicability review for the cogeneration plant. The following table summarizes the original baseline emissions, the proposed new potential emissions, and the resulting PSD applicability. Again, this information is provided *only for comparison purposes* and is not required.

Table 13A. Comparison of PSD Applicability - Original Project to Proposed Revision

Pollutant	Baseline[1] TPY	PTE by PSD Permit[2]		Net Emissions Change [3]		PSD SER TPY	Retroactive PSD? [4]	
		Original, TPY	Revised, TPY	Original, TPY	Revised, TPY		Original	Revised
CO	10388.0	2012.5	2012.5	-8376	-8376	100	No	No
SO_2	748.3	1154.3	345.0	+406	-403	40	Yes	No
Lead	0.280	0.17	0.863	-0.11	+0.583	0.600	No	No
Mercury	0.026	0.0300	0.031	+0.004	+0.005	0.100	No	No
Fluorides	0.04	21.2	4.03	+21	+3.99	3	Yes [5]	Yes [5]
SAM	22.40	34.6	20.7	+12	-1.7	7	Yes	No

Notes:

1. Baseline emissions represent actual annual emissions from the original sugar mill boilers.
2. The annual potential to emit (PTE) in tons per year (TPY) is based on the original PSD permit issued in 1993 and the revised permit for the currently proposed project.
3. The net emissions change is the difference between the potential permitted emissions and the baseline emissions. Beryllium is omitted from the table because it is no longer a PSD pollutant.
4. This represents the PSD applicability for the original project and a "retro-active" PSD applicability based on the proposed revisions.
5. Stack testing indicates that fluoride emissions when firing bagasse are higher than originally believed, which would result is higher baseline fluoride emissions. Therefore, it is possible that neither the original project nor the currently proposed project would be subject to PSD.

As indicated in the table above, the original project was subject to PSD for emissions of sulfuric acid mist, sulfur dioxide, beryllium, and fluorides. Beryllium is no longer a PSD pollutant. If the revised PSD permit were proposed in 1993, it would have been subject to PSD only potentially for fluorides. This is because the project would avoid PSD through netting, which would show emissions reductions for sulfur dioxide and sulfuric acid mist without coal firing.

Due to the difficulties with equipment problems during construction, the extended shakedown period, initial operation, and the lawsuit previously discussed, the cogeneration plant only recently surpassed 24 months of continual commercial operation. During the initial period of operation, the boilers did not perform as designed and the operators were forced to re-define the performance curve for each cogeneration boiler. In addition, more detailed information was compiled regarding the actual biomass fuels being fired. Some of this information indicates that inaccurate assumptions were made in the initial permit application for fuel contaminants such as sulfur, lead, mercury, and fluorides. In addition, it is noted that the original project was subject to PSD review for sulfur dioxides, sulfuric acid mist, beryllium, and fluorides due to the coal firing capabilities requested. Because no coal handling facilities have ever been installed and coal has never been fired, coal is being removed as an authorized fuel. The Department did consider the numerous difficulties and better available information in the review of the applicant's requests. The performance of the cogeneration boilers, as well as the biomass fuels, is now well defined for this plant.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the Air Quality Analysis, and the revised specific conditions of the draft permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the Air Quality Analysis for the project. Jeff Koerner is the project engineer responsible for reviewing the application, recommending the BACT determinations, and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

REFERENCES

1. Original Permit No. PSD-FL-196 dated September 27, 1993.
2. Draft paper titled, "Estimating Emissions from Generation and Combustion of Waste Wood" by the Wood Waste and Furniture Emissions Task Force Prepared for the North Carolina DENR dated July 1998.
3. Supplement G to the 5th edition of AP-42 (EPA's emission factor reference document) titled, "Wood Residue Combustion in Boilers" dated July 2001.
4. 1987 book titled, Natural Gas Applications for Air Pollution Control by the American Gas Association; Page 288; heading titled, "Wood Wastes"; Chapter titled, "Natural Gas Use to Facilitate Coal and Waste Combustion".
5. Article titled, "Technologies for Reducing Emissions in Coal-Fired Power Plants" from Energy Issues periodical dated August 19, 1997, Issue No. 14.
6. Technology Status Report titled, "Flue Gas Desulphurisation (FGD) Technologies" from Cleaner Coal Technology Programme periodical dated March 2000.
7. Project Summary titled, "Controlling SO_2 Emissions: An Analysis of Technologies" from EPA Report dated November 2000.

ATTACHMENT A. PERMITTING HISTORY THROUGH OCTOBER 2001

Air Permit No. PSD-FL-196: Department issued original PSD permit on 09/27/93.

Project No. 0990332-001-AC (PSD-FL-196A): OkCP requested a limit on yard trash of 30% by weight to avoid most of the applicable requirements of 40 CFR 60, Subpart Ea. Department issued modification on 02/20/96, which added specific condition 12A.

Project No. 0990332-002-AC (PSD-FL-196B): OkCP requested an extension of time for the simultaneous operation of the cogeneration boilers with the sugar mill boilers in order to perfect the steam interconnection. Department issued modification on 06/14/96. Specific condition nos. 17 and 18 were revised to extend simultaneous operation beyond the first year of commercial startup of the cogeneration boilers to April 1, 1997. The permit required the sugar mill boilers to be rendered incapable of operation no later than January 1, 1999.

Project No. 0990332-003-AC (PSD-FL-196C): OkCP requested approval to fire tire-derived fuel. Department issued modification on 01/22/97 to allow for a demonstration period to collect emissions data.

Project No. 0990332-004-AC (PSD-FL-196D): OkCP requested a revision to the emission standard and testing requirements for sulfuric acid mist. Department issued modification on 04/18/97, which retained the emission standard, but revised the test method to 8 (modified).

Project No. 0990332-005-AC (PSD-FL-196E): OkCP requested an extension of time for the simultaneous operation of the cogeneration boilers with the sugar mill boilers in order to perfect the steam interconnection. Department issued modification on 04/05/97. Specific condition nos. 17 and 18 were revised to extend simultaneous operation to April 1, 1998. The permit required the sugar mill boilers to be rendered incapable of operation no later than January 1, 1999.

Project No. 0990332-006-AC (PSD-FL-196F): OkCP requested a modification of the emissions standards for carbon monoxide, lead, and mercury. Department issued modification on 10/24/97.

Project No. 0990332-007-AC (PSD-FL-196G): OkCP requested amendment to specific condition #11 to clarify the performance test schedule. Department issued modification on 05/08/97.

Project No. 0990332-008-AC (PSD-FL-196H): OkCP requested a revision to the 24-hour rolling average for determining peak electrical generation. Application was withdrawn on 02/03/97.

Project No. 0990332-009-AC (PSD-FL-196I): OkCP requested an extension of time for the simultaneous operation of the cogeneration boilers with the sugar mill boilers in order to provide additional time to ensure that the interconnections (bagasse fuel and steam systems) were commercially and operationally reliable. Department issued modification on 06/16/98. Specific condition nos. 17 and 18 were revised to extend simultaneous operation to April 1, 2000. The permit required the sugar mill boilers to be rendered incapable of operation no later than April 1, 2001.

Project No. 0990332-010-AC (PSD-FL-196J): OkCP requested a revision to the CO emissions standard. Department issued modification of the CO averaging period on 06/24/99.

Project No. 0990332-011-AC (PSD-FL-196K): OkCP requested a modification to extend operation of Okeelanta Corporation's sugar mill boilers as standby units for the cogeneration boilers due to litigation with FPL. Department issued modification on 11/06/00.

Project No. 0990332-012-AC: OkCP requested approval to install particulate dust collectors prior to the electrostatic precipitators. Department issued approval letter on 12/22/99. Approval incorporated into modification PSD-FL-196K.

Project No. 0990332-013-AC (PSD-FL-196L): OkCP requested to add natural gas as a supplemental fuel to the biomass boilers. Department issued Final Permit in January 2001.

Project No. 0990332-014-AC (PSD-FL-196M): OkCP requested modification of the CO and SO_2 emissions standards. This is the current project under review.

Project No. 0990332-015-AC (PSD-FL-196N): OkCP requested modification to change restriction from 74.9 "Gross" MW Output to 74.9 "Net" MW Output. Department issued Final Permit in May 2001.

ATTACHMENT B. BACT FOR SIMILAR SOURCES FROM THE EPA RACT/BACT/LAER CLEARINGHOUSE

RBLC ID	Date	Facility Name	Boiler Type/Fuel	MMBtu/hour	CO, lb/MMBTU	SO_2, lb/MMBtu	Add-On Controls Equipment
AL-0047	1990	Alabama River Pulp, Co.	wood	266	0.3	0.3	None
AL-0099	1997	Mead Container Board	wood, sludge	622	0.4	0.02	None
CT-0007	> 1991	Bio-Gen Tarrington Partnership	wood	208.5	0.29	0.10	None
LA-0074	1991	Willamette Industries, Inc.	wood	940	0.30	0.008	None
ME-0013	1991	Beaver-Livermore Falls	Wood, stoker	533.6	0.30	0.023	None
MI-0139	1989	Hillman Limited Partners	wood	300	0.35	0.018	None
MI-0147	1991	Cogeneration Michigan, Inc.	wood	293	0.35	0.017	SNCR
MI-0151	1990	Grayling Generating Station L.P.	wood	450/523	0.40	ND	SNCR
MI-0180	1992	Cogeneration Michigan, Ass.	wood	523	0.40	ND	SNCR
MT-0005	1995	Plum Creek Mfg. – Columbia Falls	wood	292.4	1.6	ND	None
MT-0007	1997	Plum Creek Mfg. - Evergreen	hogged wood	225	2.25	ND	None
NH-0003	1990	Pinetree Power, Inc. - Bethlehem	wood	289	0.50	ND	None
NH-0004	1990	Pinetree Power, Inc. Tamworth	wood	404	0.50	ND	None
NY-0055	1994	KES Chateauguay Project	wood	275	0.35	0.03	Low sulfur fuels
VA-0183	1992	Mulitrade Limited Partnership	wood	373.7	0.35	0.016	SNCR
VT-0004	1990	Ryegate Wood Energy Co.	wood	300	0.30	ND	SNCR
WA-0276	1993	Scott Paper Company	wood	718	0.50	0.097, 365-day rolling avg.	SNCR

Summary of CO Standards

0.290 = minimum standard
2.250 = maximum standard
0.555 = average of standards
1.730 = 95th percentile
0.35 = median of standards

Summary of SO_2 Standards

0.008 = minimum standard
0.300 = maximum standard
0.060 = average of standards
0.210 = 95th percentile
0.022 = median of standards

DRAFT PERMIT

PERMITTEE

New Hope Power Partnership
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South (P.O. Box 9)
South Bay, FL 33493

Authorized Representative:
Mr. Rodney Williams, Plant Manager

Air Permit No. PSD-FL-196M
Project No. 0990332-014-AC
Okeelanta Cogeneration Plant
SIC No. 4911
Palm Beach County

PROJECT AND LOCATION

The original PSD permit authorized the construction of a biomass and fossil fuel-fired 74.9 MW cogeneration plant adjacent to Okeelanta Corporation's sugar mill. The original PSD permit expired on July 1, 1996. The permittee obtained several previous permit modifications that extended some construction-related activities as well as revising specific conditions of the permit. This modification revises: emissions limiting and monitoring provisions for emissions of carbon monoxide, fluorides, lead, mercury, sulfur dioxide, and sulfuric acid mist; removes the authority to fire low sulfur coal as a backup fuel; and removes the requirement to conduct stack testing for chromium, copper and arsenic. In addition, this modification updates the permit format and incorporates all previous permit modifications into a single document.

The cogeneration plant is located off U.S. Highway 27 and 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, Rule 62-212.400, F.A.C. The permittee is authorized to 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

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

Effective Date

FACILITY DESCRIPTION

The facility consists of two adjacent plants. Okeelanta Corporation operates a sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) including packaging and transshipment activities. New Hope Power Partnership operates a 74.9 net MW cogeneration plant that provides process steam for the sugar mill/refinery and generates electricity for sale to the power grid (SIC 4911). This permit addresses the cogeneration plant, which consists of the following emissions units.

ID	Emission Unit Description
001	Cogeneration Boiler A (715 MMBtu per hour)
002	Cogeneration Boiler B (715 MMBtu per hour)
003	Cogeneration Boiler C (715 MMBtu per hour)
004	Material handling and storage

REGULATORY CLASSIFICATION

Title III: Based on the Title V operation permit, the facility may have emissions of hazardous air pollutants (HAPs) at levels greater than the major source thresholds.

Title IV: Based on the Title V operation permit, the facility does not operate any units subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The facility is located in an area currently designated as "attainment" or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The cogeneration plant is considered a "fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a major source of air pollution with respect to Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality.

PPSC: The facility is not subject to Chapter 62-17, F.A.C. for Power Plant Site Certification because it produces less than 75 MW of steam-generated electrical power.

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

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit 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.

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.

APPENDICES

The following Appendices are attached in Section IV 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

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.

- Initial air construction Permit No. PSD-FL-196 issued September 27, 1993 and all subsequent modifications.
- Permit application received on January 2, 2001 and all related correspondence to make complete.
- Initial draft permit package issued on (Draft).

CITATION FORMAT

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

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 the 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. However, construction of the cogeneration plant is complete and commercial operation has commenced. This revised permit does not authorize any additional construction.

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: Within 180 days of the effective date of this modified PSD permit, the permittee shall submit an application for a revised Title V permit to incorporate the changes and operate the cogeneration plant. 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. The application shall include a Compliance Assurance Monitoring Plan. The application shall be submitted to the Department's Bureau of Air Regulation with copies to each Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

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 455,400 pounds per hour of steam at 1500 psig and 975° F. *Fuels and Capacity*: The primary fuel is biomass (715 MM Btu 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 foot diameter stack that is at least 199 feet tall and with a volumetric flow rate of approximately 246,000 acfm at 295° F.
Emissions Unit 004: Material handling and storage including unloading operations, stockpiles, transfer operations, conveyors, screens, crushers, hoppers, silos, and storage tanks.

CONSTRUCTION DETAILS

1. Generating Capacity: Construction of the proposed cogeneration plant shall reasonably conform to the plans described in the application. The plant shall be designed, constructed, and operated such that the generating capacity does not exceed 74.9 net megawatt (MW) based on a 1-hour average. The owner or operator shall not modify the cogeneration plant in any way that would cause the plant to exceed the limit on maximum net generating capacity. The hourly average net generation rate shall be recorded and retained for at least 5 years.
2. Boiler Design: The cogeneration boilers shall consist of spreader stoker units designed to fire biomass as the primary fuel with pipeline-quality natural gas and distillate oil as auxiliary fuels. Natural gas and distillate oil are fired at startup, 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 apply for a permit modification before firing any other fuel.}
3. 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.
4. 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.
5. 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. The preliminary auxiliary burner design indicates that a single burner (150 MMBtu/hour, nominal) will be installed in each corner of each boiler for a total of four burners; however this is subject to change.
   - 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 NOx.
- 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 monitors (CEMS) and continuous opacity monitors (COMS) to measure and record emissions of carbon monoxide (CO), nitrogen oxides (NOx), opacity, oxygen (O_2), and sulfur dioxide (SO_2) 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 NOx emissions control plan based on previous monitoring data that shall be implemented in case the NOx monitoring system is down. The plan shall identify the minimum urea injection rate that has demonstrated continuous compliance with the NOx emissions standard at various load conditions.

9. Materials Handling Controls: For the fly ash handling and mercury control system reactant storage systems:

   a. 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.

   b. 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 715 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 maximum heat input to the entire plant (total for all three boilers combined) shall not exceed 11.5 x 10^{+12} Btu during any consecutive 12-month period. The steam production of each boiler shall not exceed an average of 455,418 pounds per hour at 1,500 psig and 975°F.

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:

    a. 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 ASTM Methods 3050/6010 and reported in ppm by weight, dry. Samples shall be taken at least two weeks apart.

    b. 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 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 very low sulfur distillate oil and pipeline-quality 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-quality natural gas or very low sulfur 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_2 emissions and the 12-month rolling total SO_2 emissions shall be determined and kept in a log.

15. Emergency Standby: The existing sugar mill boilers shall comply with the following requirements.

    a. Sugar mill boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15 may be retained for emergency standby operation until April 1, 2002. These boilers shall only operate in the event of electrical or mechanical failure of all three of the cogeneration boilers. Simultaneous operation of any of these sugar mill boilers with any of the cogeneration boilers is prohibited. Sugar mill boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15 shall be permanently shutdown and rendered incapable of operation no later than October 1, 2002.

    b. Each sugar mill boiler shall comply with its most recent air construction and operation permit, including all emissions performance, testing, and monitoring requirements as well as any applicable Alternate Sampling Procedures approved by the Department. The sugar mill boilers shall only fire fuels approved in the most recent permits.

16. Auxiliary Boiler: Sugar mill boiler No. 16 shall be operated in accordance with revised Permit No. PSD-FL-169A and the subsequently revised Title V operation permit.

EMISSIONS LIMITING STANDARDS

17. 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[j]	
		lb/MMBtu	lb/hr
Carbon Monoxide (CO)[a]	30-day rolling CEMS avg.	0.50	357.5
	12-month rolling CEMS avg.	0.35	
Nitrogen Oxides (NOx)[b]	30-day rolling CEMS avg.	0.15	107.3
Sulfur Dioxide (SO_2)[c]	24-hour rolling CEMS avg.	0.20	143.0
	30-day rolling CEMS avg.	0.10	
	12-month rolling CEMS avg.	0.06	
Stack Opacity[d]	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_{10})[e]	3-run test avg.	0.03	21.5
Volatile Organic Compounds (VOC)[f]	3-run test avg.	0.06	42.9
Lead[g]	3-run test avg.	1.5×10^{-04}	NA
Mercury[h]	3-run test avg.	5.4×10^{-06}	NA
Fluorides[i]	Fluoride emissions shall be minimized by firing biomass as the primary fuel with natural gas and very low sulfur distillate oil as auxiliary fuels.		

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 NOx 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 NOx 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_2 standards shall be determined by data collected from the required SO_2 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_2 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_2 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_2 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_{10} emissions, it shall be assumed that all particulate matter emitted is PM_{10}.

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 lead standards shall be determined by the average of three test runs conducted in accordance with EPA Method 12 or 29.

h. 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.

i. This fuel specification is the BACT standard for fluoride emissions. {Permitting Note: For reporting purposes only, the fluoride emissions factor for firing biomass is 1.9×10^{-04} lb/MMBtu.

j. Each boiler shall comply with the standards when firing any combination of authorized fuels. Required compliance tests shall be performed in accordance with the requirements of Condition No. 20. 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.}

18. 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

19. 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 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 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. 17. 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 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_2 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 provide a summary of startups, shutdowns, and malfunctions for each case in which monitoring data was excluded due to such events. For each boiler, the summary shall include the number of each event per year, the annual CO emissions for each event per year, and the annual NOx emissions for each event per year.

   [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

20. Stack Test Requirements

   a. *Initial Tests*: Within 90 days of the effective date of this permit, the permittee shall conduct compliance tests for emissions of lead, mercury, particulate matter, and volatile organic compounds. If conducted with the 12-month period prior to the effective date of this permit, previous emissions tests may be used to demonstrate compliance for these pollutants. The Department may require initial tests to be repeated if major physical or operational changes are made that affect main components such as the boiler, fuels, and/or 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 lead, 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 643 and 715 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), or any other method as approved by the Department, in accordance with Rule 62-297.620, F.A.C.

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_2
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 {Permitting Note: Although each unit is required to monitor opacity with a COMS, visible observations may also be used to demonstrate compliance.}
10	Carbon monoxide emissions
12	Inorganic lead emissions
19	Calculation of sulfur dioxide and nitrogen oxide emission rates
25A	Volatile organic compounds emissions {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".
29	Multiple metals emissions
101A	Particulate and gaseous mercury emissions

No other methods may be used to demonstrate compliance unless prior written approval is received from the Department in accordance with a permit modification or an alternate sampling procedure issued pursuant to 62-297.620, F.A.C. 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, NOx, opacity, and SO_2. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

21. Continuous Monitor Requirements: The permittee shall demonstrate compliance with the emissions standards for CO, NOx, opacity, and SO_2 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.

22. 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. The fuel usage summary shall include the monthly heat input and the 12-month rolling total heat input for the cogeneration boilers. 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.

23. 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(2), F.A.C.]

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CITATION FORMAT

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 CFR 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, Florida Statutes. 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), Florida Statutes, 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 Florida Statutes 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 Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida

Statutes. 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 Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code 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 (X);
    b. Determination of Prevention of Significant Deterioration (X); and
    c. Compliance with New Source Performance Standards (X).

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.

{Permitting Note: The following conditions are generally applicable to all emissions units.}

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 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.]

4. 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.]

5. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents 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.]

6. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. [Rule 62-296.320(2), F.A.C.]

7. 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 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

8. 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.]

TESTING REQUIREMENTS

9. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. 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. [Rule 62-297.310(2), F.A.C.]

10. 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.]

11. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. *Required Sampling Time.* 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. 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.

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.

[Rule 62-297.310(4), F.A.C.]

12. Determination of Process Variables

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.

[Rule 62-297.310(5), F.A.C.]

13. Sampling Facilities: The permittee shall provide stack testing facilities and sampling locations in accordance with Rule 62-297.310(6), F.A.C.

14. Test Notification: 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. [Rule 62-297.310(7)(a)9, F.A.C. and 40 CFR 60.7, 60.8]

15. 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. [Rule 62-297.310(7)(b), F.A.C.]

RECORDS AND REPORTS

16. 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. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

17. 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(2), F.A.C.]

18. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to each Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.]

PSD Applicability

The existing facility is located in Palm Beach County, an area that is in attainment with (or designated as unclassifiable for) all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The cogeneration plant is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Potential emissions from the plant are greater than 100 tons per year for at least one regulated pollutant. As such, the facility is "major" with respect to the Prevention of Significant Deterioration (PSD) of Air Quality. The proposed project will result in net emissions increases for carbon monoxide, fluorides, sulfur dioxide, and sulfuric acid mist that are greater than the PSD significant emission rates identified in Table 62-212.400-2, F.A.C. Therefore, the project is subject to PSD review and the Department must determine the Best Available Control Technology (BACT) for these pollutants in accordance with Rule 62-212.400, F.A.C.

Carbon Monoxide (CO)

BACT Standards: 0.50 lb/MMBtu based on a 30-day rolling CEMS average, and
0.35 lb/MMBtu based on a 12-month rolling CEMS average

Control Technology: CO emissions are minimized by good combustion practices.

Compliance Method: Compliance demonstrated by continuous emissions monitoring system (CEMS).

Comments: In 1993, the original project did not require a BACT determination because the result was a net CO emissions decrease of more than 8000 tons per year due to the shutdown of existing sugar mill boilers. The 2001 modification did not increase allowable emissions, but could result in a net increase of actual emissions. Therefore, a BACT determination was required for the existing cogeneration boilers.

Fluorides (Fl)

BACT Standard: Fluoride emissions shall be minimized by firing biomass as the primary fuel with natural gas and very low sulfur distillate oil as auxiliary fuels.

Control Technology: Fluoride emissions minimized by firing clean fuels.

Compliance Method: Compliance assumed providing only authorized fuels are fired.

Comments: In 1993, the original project required a BACT determination for fluoride emissions due to the inclusion of coal as an emergency backup fuel. The 2001 modification removed the authorization to fire coal as well as the fluoride emissions standards when firing coal and distillate oil. Uncontrolled fluoride emissions from firing biomass, natural gas, and distillate oil are expected to be much less than 4 tons per year.

Sulfur Dioxide (SO_2)

BACT Standards: 0.20 lb/MMBtu based on a 24-hour block CEMS average;
0.10 lb/MMBtu based on a 30-day rolling CEMS average; and
0.06 lb/MMBtu based on a 12-month rolling CEMS average

Control Technology: SO_2 emissions are minimized by firing biomass as the primary fuel with natural gas and very low sulfur distillate oil as auxiliary fuels (low sulfur fuels).

Compliance Method: Compliance demonstrated by continuous emissions monitoring system (CEMS).

Comments: In 1993, the original project required a BACT determination for SO_2 emissions due to the inclusion of coal as an emergency backup fuel. The 2001 modification removed the authorization to fire coal and resulted in a decrease in allowable SO_2 emissions. However, actual SO_2 emissions were expected to result in a significant net increase, which required a revised BACT determination for the existing cogeneration boilers.

Sulfuric Acid Mist (SAM)

BACT Standard: Potential SAM emissions shall be minimized by the effective control of SO_2 emissions with the firing of low sulfur fuels.

Control Technology: SAM emissions are minimized by firing biomass as the primary fuel with natural gas and very low sulfur distillate oil as auxiliary fuels (low sulfur fuels).

Compliance Method: Compliance assumed providing only authorized fuels are fired.

Comments: In 1993, the original project required a BACT determination for SAM emissions due to the inclusion of coal as an emergency backup fuel. The 2001 modification removed the authorization to fire coal and resulted in a decrease in allowable SAM emissions. However, actual SAM emissions were expected to result in a significant net increase, which required a revised BACT determination for the existing cogeneration boilers. Based on stack testing for the existing cogeneration boilers, SAM emissions are estimated to be 6% of the total SO_2 emissions.

Final BACT Determinations

In accordance with Rule 62-212.400, F.A.C., the Department determines that the above standards represent the Best Available Control Technology (BACT) for the existing biomass cogeneration boilers. 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 this project.

Determination By:

(DRAFT)

J. F. Koerner, P.E., Project Engineer (Date)
New Source Review Section

Recommended By:

(DRAFT)

C. H. Fancy, Chief (Date)
Bureau of Air Regulation

Approved By:

(DRAFT)

Howard L. Rhodes, Director (Date)
Division of Air Resources Management

CONTINUOUS MONITOR REQUIREMENTS

{Permitting Note: The following summarizes the basic monitoring requirements for the cogeneration boilers.}

1. Process and Control Parameters: The permittee shall install, calibrate, maintain, and operate continuous monitoring systems to measure and record the following process and control equipment parameters:

   a. *Power Output.* The net power generation (MW) delivered for sale to the electrical power grid shall be continuously monitored and recorded in 1-hour block averages.

   b. *Fuel Feed Rate.* Fuel flow meters equipped with totalizers are required to monitor and record the fuel feed rates for distillate oil (gallons) and natural gas (million cubic feet). Biomass feed rates (tons of bagasse and tons of wood) shall be calculated and recorded based on updated fuel heating values. In addition, the heat input to each boiler shall be sufficiently monitored to provide an hourly average for each 1-hour block of operation. Calculation methods for the biomass feed rate and heat input rates shall be detailed in the Title V operation permit.

   c. *Steam Parameters.* Each cogeneration boiler shall be equipped with monitors to measure and record the steam temperature (° F), steam pressure (psig), and steam production (pounds).

   d. *Urea Injection Rate (SNCR System).* The urea injection rate shall be continuously monitored and recorded for each cogeneration boiler. The urea injection rate shall be compared to actual NOx emissions data recorded by the CEMS. The permittee shall identify minimum urea injection rates for various load conditions that ensure compliance with the NOx standards. Should the NOx CEMS be unavailable, the urea injection rate shall be maintained at an appropriate minimum level.

   e. *Activated Carbon Injection Rate (Mercury Control System).* If the mercury injection system is reactivated, the carbon injection rate shall be continuously monitored and recorded. Based on the testing required in this permit, the permittee shall identify and maintain minimum carbon injection rates to ensure effective control of mercury emissions.

   The permittee shall maintain written procedures for inspecting, calibrating, and maintaining the process and control monitoring equipment. [Rules 62-4.070 and 62-212.400(BACT), F.A.C.]

2. CEMS and COMS: For each cogeneration boiler, the permittee shall install, calibrate, maintain, and operate continuous emissions monitors (CEMS) and continuous opacity monitors (COMS) to measure and record emissions of carbon monoxide (CO), nitrogen oxides (NOx), oxygen (O_2), sulfur dioxide (SO_2), and opacity in a manner sufficient to demonstrate compliance with the standards of this permit.

   a. *Performance Specifications.* Each monitor shall be located in the ductwork between the electrostatic precipitator and the stack (or in the stack) to obtain emissions measurements representative of actual stack emissions. Each CEMS and COMS shall comply with the corresponding performance specifications that identify location, installation, design, performance, and reporting requirements.

      (1) Opacity shall comply with Performance Specification 1 in Appendix B of 40 CFR 60.

      (2) NOx and SO_2 CEMS shall comply with Performance Specification 2 in Appendix B of 40 CFR 60. The SO_2 reference method for the annual RATA shall be EPA Method 6 (or 6C) in Appendix A of 40 CFR 60. The NOx reference method for the annual RATA shall be EPA Method 7 (or 7E) in Appendix A of 40 CFR 60.

      (3) O_2 CEMS shall comply with Performance Specification 3 in Appendix B of 40 CFR 60. The O_2 reference method for the annual RATA shall be EPA Method 3A Appendix A of 40 CFR 60.

      (4) CO CEMS shall meet Performance Specification 4 or 4A in Appendix B of 40 CFR 60. The CO reference method for the annual RATA shall be EPA Method 10 in Appendix A of 40 CFR 60.

   b. *Data Collection.* Each CEMS and COMS shall record emissions data at all times including episodes of startup, shutdown, and malfunction. Emissions data recorded during periods of startup, shutdown, or malfunction may only be excluded from the compliance averages in accordance with the requirements specified in Section III of this permit. To the extent practicable, the permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions.

   Each CEMS shall be designed and operated to sample, analyze, and record emissions data evenly spaced over a 1-

hour period. Each 1-hour average shall be computed using at least one data point in each fifteen minute quadrant of the 1-hour.block during which the unit combusted fuel. Notwithstanding this requirement, each 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. All valid measurements or data points collected during a 1-hour block shall be used to calculate the 1-hour emission averages. CO, NOx, and SO_2 CEMS shall express the 1-hour emission averages in terms of "lb/MMBtu of heat input". O_2 CEMS shall express the 1-hour emission average in terms of "percent by volume". A 30-day rolling emission average shall be the average of all valid 1-hour emission averages collected during the 30-day period. A 12-month rolling emission average shall be the average of all valid 1-hour emission averages collected during the 12-month period. NOx and SO2 CEMS shall comply with NSPS Subpart Da in 40 CFR 60.

Each COMS shall be designed and operated to complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period. Opacity shall be recorded in 6-minute block averages.

c. *Quality Assurance Procedures.* Each CEMS shall comply with the applicable quality assurance procedures specified in Appendix F of 40 CFR 60. These procedures include methods such as calibration, calibration drift, data recording, accuracy assessment, calculations, audit procedures, preventive maintenance, corrective actions, and reporting.

d. *Monitor Availability.* Monitor availability shall not be less than 95% in any calendar quarter. 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.

e. *Other Applicable Requirements*: Each CEMS shall comply with the following applicable requirements Rules 62-204.800 and 62-297.520, F.A.C. (Continuous Monitor Performance Specifications); 40 CFR 60.13 (Subpart A - Monitoring Requirements); 40 CFR 60.47a (Subpart Da - Emissions Monitoring); 40 CFR 60.48a (Subpart Da - Compliance Determination Procedures and Methods); 60.49a (Subpart Da - Reporting Requirements).

f. *Quarterly Reports*: For each cogeneration boiler, the permittee shall submit the report on the following page to summarize each required continuous emissions and opacity monitoring system. The authorized representative shall certify that the information provided in each quarterly report is true, accurate, and complete to the best of his/her knowledge. Each quarterly report is due no later than 30 days following the calendar quarter.

QUARTERLY CONTINUOUS MONITOR SYSTEM (CMS) REPORTS

Facility Name	ARMS ID No.	Title V Air Permit No.
Okeelanta Cogeneration Plant	0990332	

Facility Address/Location

Located off U.S. Highway 27 South, approximately six miles south of South Bay in Palm Beach County, Florida

Emissions Unit Description	Unit Operation in Calendar Quarter
Spreader stoker boiler with maximum heat input of 715 MMBtu/hour ARMS EU ID No. ______ Cogeneration Boiler: ___ A ___ B ___ C	_________ hours

Control Equipment

Mercury - activated carbon injection; Nitrogen Oxides – low NOx burners and selective non-catalytic reduction (NOx) system; Particulate Matter – mechanical dust collectors and electrostatic precipitators

Primary Fuel	Auxiliary Fuels
Biomass, which includes bagasse from adjacent sugar mill and wood material from area suppliers (clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter)	Pipeline-quality natural gas Distillate oil (≤ 0.05% sulfur by wt.)

Pollutant Monitored *(Check one.)*	Calendar Quarter of Operation Covered *(Check one.)*
___ **CO** ___ **NOx** ___ **SO_2** ___ **Opacity**	**Year:** _________ ___ **1** ___ **2** ___ **3** ___ **4**

Continuous Monitor MS Information	Emission Standards
Manufacturer: ______________________	_______ lb/MMBtu of heat input, 30-day rolling avg.
Model No. ______________________	_______ lb/MMBtu of heat input, 12-month rolling avg.
Date of last certification or audit: ______________	

Emission Data Summary	CMS Performance Summary
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... _____	a. Monitor Equipment Malfunctions .... _____
b. Control equipment problems .... _____	b. Non-Monitor Equipment Malfunctions .... _____
c. Process problems .... _____	c. Quality Assurance Calibration .... _____
d. Other known causes .... _____	d. Other Known Causes .... _____
e. Unknown causes .... _____	e. Unknown Causes .... _____
2. Total duration of excess emissions .... _____	2. Total CMS Downtime .... _____
3. [Total duration of excess emissions] x (100%) .... _____ [Total source operating time] c	3. [Total CMS Downtime] x (100%) .... _____ [Total source operating time]
Note: Report "excess emissions" as emission averages that are in excess of a permitted emissions standard. For gases, report excess emissions in terms of hours. For opacity, report excess emissions in terms of minutes.	*If monitor availability is not at least 95%, provide a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability*

Emissions Data Exclusion

1. Report the number of 1-hour emissions averages excluded the reporting period due to:
   a. Startup .... _____
   b. Shutdown .... _____
   c. Malfunction .... _____
   d. Total .... _____
2. On a separate page, summarize each malfunction event, the cause (if known), and corrective actions taken.
3. On a separate page, describe any changes to CMS, process or controls during last quarter.

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
Okeelanta cogeneration Plant
~~8001 U. S.~~ Highway 27 South
South Bay, FL 33493
PO Box 9

COMPLETE THIS SECTION ON DELIVERY

A. Received by (*Please Print Clearly*) [illegible]

B. Date of Delivery 12-26-01

C. Signature
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☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

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City, State, ZIP+ 4
S. Bay, FL 33493

PS Form 3800, May 2000 **See Reverse for Instructions**