ATTACHMENT A: Boundaries of the Certified Site

(To be attached upon receipt.)

ATTACHMENT B: Boundaries of the Certified Area

(To be attached upon receipt.)

ATTACHMENT C: Wetland Mitigation Plan (if any)

APPENDIX I. Air Construction Permits

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DER File No. AC50-219413
PSD-FL-196
Palm Beach County

Mr. Gus Cepero, Vice President
Okeelanta Power Limited Partnership
P. O. Box 86
South Bay, Florida 33493
_____/

Enclosed is construction Permit Number AC50-219413 (PSD-FL-196) for a 74.9 megawatt (MW) electric cogeneration facility to be constructed at the Okeelanta Corporation sugar mill located 6 miles south of South Bay, off U.S. Highway 27 in Palm Beach County, Florida. This permit is issued pursuant to Section 403, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on Sept 24, 1993 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED,
on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

(Clerk) 9-27-93 (Date)

Copies furnished to:
David Knowles, SD
Isidore Goldman, SED
James Stormer, PBCHD
Jewell Harper, EPA
John Bunyak, NPS
David Buff, KBN

Final Determination

Okeelanta Power Limited Partnership
South Bay, Palm Beach County, Florida

74.9 Megawatt (MW) Electric Cogeneration Facility

Permit No.: AC 50-219413
PSD-FL-196

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

September 17, 1993

FINAL DETERMINATION

The Technical Evaluation and Preliminary Determination for a permit to construct (AC 50-219413/PSD-FL-196) a 71.25 megawatt (MW) electric cogeneration facility for Okeelanta Power Limited Partnership, P.O. Box 86, South Bay, Florida 33493, was distributed on June 3, 1993. The cogeneration facility will be built at Okeelanta Corporation's sugar mill located 6 miles south of South Bay, off U.S. Highway 27, Palm Beach County, Florida. The Notice of Intent to Issue was published in the Palm Beach Post on June 9, 1993. Copies of the evaluation were available for public inspection at the Department offices in Tallahassee, Ft. Myers, and West Palm Beach, and at the Palm Beach County Health Department office in West Palm Beach.

The Environmental Protection Agency and National Park Service had no negative comments on the proposed permit.

In letters dated July 2 and August 11, 1993, the applicant requested that the plant be allowed to generate 74.9 megawatts (MW) of electricity as proposed in the application, that they be allowed to burn small quantities of treated wood that may escape detection by their inspection program provided the air pollution standards are not exceeded, that the prohibition on the burning of "special waste" be deleted from the permit, that they not be required to analyze the ash, that the permit be reworded to state that the fossil fuel heat input to the boilers will be less than 25 percent on a quarterly basis instead of 25 percent on an annual basis, that the nitrogen oxide emissions be corrected from 873.1 to 862.5 tons per year (TPY), that a 3-hour sulfur dioxide emission limit for coal be added to the permit, that a visible emission standard be added to the permit, that they not be required to test the emissions from all allowed fuels during the first 180 days of operation, that they be allowed to use other test methods than the ones listed in the permit, that they be allowed more than 2 hours for excess emissions during startup conditions, and that they not be required to cover the inactive coal storage pile. Except for the request to not cover the inactive coal pile or analyze the ash, the Department finds their comments acceptable and have made the following changes, along with minor editioral changes to the proposed permit:

Specific conditions Nos. 1, 11, and 15, the project description, and the BACT and RACT determinations were revised from 71.25 to 74.9 MW, 1-hour average, except during emission compliance and equipment performance tests. This change does not increase allowable heat input or emissions of any air pollutant.

Specific condition No. 12 was revised to incorporate a plan to minimize treated/painted wood from being burned in the cogeneration facility. Limits on metals associated with treated wood needed to prevent the Acceptable Ambient Concentration from being exceeded were added to the permit.

Specific Condition No. 17 was revised to allow limited operation of both existing bagasse boilers and new cogeneration boilers during the first year while the cogeneration facility is being debugged.

Specific condition No. 18 was revised to allow additional time for excess emissions during startup. Limits on the number of startups during a time period were added to the permit.

Specific condition No. 20 was revised to include a visible emission standard and a 3-hour sulfur dioxide standard for coal based on the new source performance standard for electrical utility steam generating units.

Specific condition No. 21 was revised to allow the use of additional EPA approved compliance test methods.

Specific condition No. 23 was corrected to require a 15 day notice instead of 10 days as listed in the proposed permit prior to any scheduled compliance test.

The final action of the Department will be to issue construction permit No. AC 50-219413 (PSD-FL-196) as proposed in the Technical Evaluation and Preliminary Determination except for the changes noted above.

Florida Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Okeelanta Power Limited Partnership
P. O. Box 86
South Bay, FL 33493

Permit Number: AC50-219413
PSD-FL-196
Expiration Date: July 1, 1996
County: Palm Beach
Latitude/Longitude: 26°35'00"N
80°45'00"W
Project: Cogeneration Facility

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-210, 212, 272, 275, 296, and 297; and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and specifically described as follows:

A 74.9 megawatt (gross) electric, (1-hour average), cogeneration facility (biomass--bagasse and wood waste material as the primary fuel, No. 2 fuel oil as a supplementary fuel, and low sulfur coal as an alternate fuel) located at Okeelanta Corporation's sugar mill that is 6 miles south of South Bay, off U.S. Highway 27, Palm Beach County, Florida. The cogeneration facility contains three Zurn spreader-stoker or equivalent steam boilers with a design heat input for each boiler of 715 MMBtu/hr on biomass and 490 MMBtu/hr on fossil fuels. Each boiler will produce approximately 455,400 lbs/hr of steam at 1,500 psig and 975°F. Particulate matter, nitrogen oxides, and mercury emissions from each boiler will be controlled by Research-Cottrell (or equivalent) electrostatic precipitator, Thermal DeNO$_X$ (or equivalent) selective non-catalytic reduction system, and an activated carbon injection system (or equivalent), respectively. Auxiliary equipment includes feed and ash handling systems, steam turbines and condensers, electric generators, cooling towers, and stacks that are 8.0 ft. in diameter and a minimum 199 ft. high.

The UTM coordinates of this facility are Zone 17, 524.9 km E and 2940.1 km N.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:
1. Application received September 30, 1992.
2. DER letter dated November 3, 1992.
3. KBN letter dated December 4, 1992.
4. Carlton letter dated December 23, 1992.
5. KBN letter dated February 17, 1993.
6. KBN letter dated May 25, 1993.
7. KBN letter dated July 2, 1993.
8. KBN letter dated August 11, 1993.

Printed on recycled paper.

GENERAL CONDITIONS:

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 any 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 of 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 acknowledgement 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

GENERAL CONDITIONS:

reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any 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.

GENERAL CONDITIONS:

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-730.300, 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:

(x) Determination of Best Available Control Technology (BACT)
(x) Determination of Prevention of Significant Deterioration (PSD)
(x) Compliance with New Source Performance Standards (NSPS)

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 for 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:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

GENERAL CONDITIONS:

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.

SPECIFIC CONDITIONS:

Construction Details

1. Construction of the proposed cogeneration facility shall reasonably conform to the plans described in the application. The facility shall be designed, constructed, and operated so that its gross generating capacity shall not exceed 74.9 megawatt (MW), 1-hour average, except during scheduled emission compliance and equipment performance tests. Equipment performance testing in excess of 74.9 shall be limited to a total of 24 hours (cumulative) during the 180-day calendar period after initial firing of each boiler.

The permittee shall provide detailed engineering plans, 30 days after they become available, demonstrating that the steam electric generating system will not produce more than 74.9 MW at design maximum steam conditions. Such demonstration may include plans for installation of a steam pressure relief valve. If the steam electric generating system is designed with a pressure relief valve, such valve shall be installed and maintained as a requirement of this permit.

2. Boilers No. 1, 2 and 3 shall be of the spreader stoker type with a maximum heat input of 715 MMBtu/hr with biomass fuel and 490 MMBtu/hr with fossil fuels.

3. Each boiler shall have an individual stack, and each stack must have a minimum height of 199 feet. The stack sampling facilities for each stack must comply with F.A.C. Rule 17-297.345.

4. Each boiler shall be equipped with instruments to measure the fuel feed rate, steam production, steam pressure, and steam temperature.

5. Each boiler shall be equipped with a:

-Electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter;
-Selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of NO_x; and
-Carbon injection system (or equivalent) for mercury emissions control.

SPECIFIC CONDITIONS:

6. The permittee shall install and operate continuous monitoring devices for each main boiler exhaust for opacity, nitrogen oxides (NO_X), sulfur dioxide (SO_2), oxygen (O_2), and carbon monoxide (CO).

The monitoring devices shall meet the applicable requirements of Section 17-297.500, F.A.C., and 40 CFR 60.47a. The opacity monitor shall be placed in the duct work between the electrostatic precipitator and the stack or in the stack.

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 maintain air/fuel ratio parameters at an optimum. Operating procedures shall be established based on the initial emission compliance tests required by Specific Condition No. 21 below. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" shall be used as a guide. An operating plan shall be submitted to the Department within 90 days of completion of such tests.

7. For the electrostatic precipitator, the selective non-catalytic reduction process (SNCR), and the activated carbon injection mercury control system (equivalent controls allowed):

a. The permittee shall submit to the Department copies of technical data pertaining to the selected PM, NO_X, and mercury emission controls within thirty (30) days after it becomes available. These data should include, but not be limited to, guaranteed efficiency and emission rates and major design parameters.

8. 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 a 0.01 gr/acf outlet dust loading. The permittee must submit to the Department copies of technical data pertaining to the selected particulate emissions control for the mercury control system reactant storage silos within thirty (30) days after it becomes available. These data should include, but not be limited to, guaranteed efficiency, emission rates, and major design parameters.

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 it being discharged into the disposal bin.

SPECIFIC CONDITIONS:

9. Prior to operation of the source, the permittee shall submit to the Department an operation and maintenance plan that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

10. During land clearing and site preparation, wetting operations or other soil treatment techniques appropriate for controlling unconfined particulates, including grass seeding and mulching of disturbed areas, shall be undertaken and implemented. Any open burning of land clearing debris on this site shall be performed in compliance with Department regulations.

Operational and Emission Restrictions

11. The proposed cogeneration facility steam generating units shall be constructed and operated in accordance with the capabilities and specifications described in the application. The facility shall not exceed 74.9 (gross) megawatt generating capacity, 1 hour average, except during emission compliance and equipment performance tests. Equipment performance testing shall be limited to a 180-day calendar period after initial firing of each boiler. The hourly average generation rate shall be recorded in a log and the log retained for at least 2 years. The maximum heat input rate for each steam generator shall not exceed 715 MMBtu/hr when burning 100 percent biomass and 490 MMBtu/hr when burning 100 percent No. 2 fuel oil or low sulfur coal. Maximum heat input to the entire facility (total all three boilers) shall not exceed 11.5 x 10^{12} Btu per year. Steam production of each boiler shall not exceed an average of 455,418 lbs/hr at 1,500 psig, 975°F.

12. The primary fuel for the facility shall be biomass--bagasse and wood waste material. Authorized wood waste material is clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter.

The biomass fuel used at the cogeneration facility shall not contain hazardous substances, hazardous wastes, biomedical wastes, or garbage. The fuel used at the cogeneration facility 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 waste or similar vegetative matter that has been delivered to the facility 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 waste and vegetative matter.

SPECIFIC CONDITIONS:

The permittee shall design and implement a management and testing program for the wood waste and other materials delivered to the facility 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. This program shall be submitted to the Department's Bureau of Air Regulation for review and approval at least 60 days before the commencement of operations of the cogeneration facility. At a minimum, 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. Fuel scheduled for burning shall be inspected daily. Fuel tests shall be conducted weekly for the first year of operations at the facility and monthly thereafter, if the Department determines on the basis of the prior test results that less frequent testing is appropriate. A representative sample of ash for the biomass burned during each month for the first year of operation shall be analyzed for copper, chromium and arsenic by appropriate analytical procedures per 40 CFR 261, Appendix III, described in SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods. Wood waste containing more than 70.7 ppm arsenic or 83.3 ppm chromium or 62.8 ppm copper shall not be burned based on an analysis of a composite sample.

13. Any fuel oil burned in the facility shall be "new" No. 2 fuel oil with a maximum sulfur content of 0.05 percent sulfur as determined by the appropriate test method listed in 40 CFR 60.17. "New" oil means an oil which has been refined from crude oil and has not been used in any manner that may contaminate it.

14. Any coal burned in the facility shall be low sulfur coal with a maximum sulfur content of 0.70 percent and a maximum potential emission equivalent to 1.2 lb SO_2/MMBtu.

15. The consumption of No. 2 fuel oil shall be less than 25 percent of the total heat input to each boiler unit in any calendar quarter. Not more than 73,714 tons of coal shall be burned at this facility during any 12-month period. The combined heat input for coal and oil shall be less than 25 percent of the heat input on a calendar quarter basis.

16. The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, beryllium content (coal only), sulfur content, and equivalent SO_2 emission rate (in lbs/MMBtu) of each fuel oil and coal delivery shall be kept in a log for at least two years. For each calendar month, the calculated SO_2 emissions and 12-month rolling average shall be determined (in tons) and kept in a log.

SPECIFIC CONDITIONS:

17. During the first three years of commercial cogeneration facility operation, the existing Boilers Nos. 4, 5, 6, 10, 11, 12, 14, and 15 (Permit Nos. AO50-169210, 190690, 175414, 190693, 175411, 169215, 189904, and 209094, respectively) may be retained for standby operation. During the period from initial firing to commercial operation, all three cogeneration boilers can be operated simultaneously with the existing boilers. Only biomass and No. 2 fuel oil may be used in the cogeneration boilers during this period. If more than 910,836 lb/hr steam is generated in the cogeneration boilers, steam in excess of 910,836 lb/hr must be sent to the Okeelanta sugar mill, and the existing boiler's steam production reduced by an equivalent amount. This period shall not exceed a total duration of 12 months. During this 12-month period, simultaneous operation of the existing boilers and the cogeneration boilers shall not occur on more than a total of 90 calendar days. After the first year of cogeneration facility operation, the existing boilers may be operated only when all three cogeneration boilers are shutdown. During operation, the existing boilers must meet all requirements in the most recent construction and operation permits for the boilers. These existing boilers shall be shutdown and rendered incapable of operation within three (3) years of commercial startup of the cogeneration facility, but no later than January 1, 1999.

18. Boiler No. 16 (AC50-191876) may be retained as a standby boiler for the cogeneration facility provided its permit is amended to authorize standby use. Boiler No. 16 may be operated during initial startup, debugging, and testing of the cogeneration facility for a period not to exceed 12 months following initial firing of fuel in the new boilers. After the first year of cogeneration operation, this boiler may be operated only when one or more of the three cogeneration boilers are shutdown. During operation, this boiler must meet all requirements in the current construction or operating permit for the boiler.

19. For the biomass, coal, fly ash, and mercury control system reactant handling facilities:

a. All conveyors and conveyor transfer points shall be enclosed to preclude PM emissions (except those directly associated with the stacker/reclaimers, for which enclosure is operationally infeasible).

b. Inactive coal storage piles shall be shaped, compacted, and oriented to minimize wind erosion. Sod, wetting agents, synthetic or other appropriate materials shall be used to cover those portions of the inactive coal pile that are prone to wind or water erosion.

SPECIFIC CONDITIONS:

c. Water sprays or chemical wetting agents and stabilizers shall be applied to storage piles, handling equipment, unenclosed transfer points, etc. during dry periods and as necessary to all facilities to maintain an opacity of less than or equal to 5 percent, except when adding, moving or removing coal from the coal pile, which would be allowed no more than 20 percent opacity.

d. 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. Particulate matter emissions from each of the three silos shall not exceed a visible emission reading of 5 percent opacity. A visible emission test is to be performed annually on each silo.

20. Visible emissions from any boiler shall not exceed 20 percent opacity, 6-minute average, except up to 27 percent opacity is allowed for up to 6 minutes in any 1-hour period. Based on a maximum heat input to each boiler of 715 MMBtu/hr for biomass fuels and 490 MMBtu/hr for No. 2 fuel oil and coal, stack emissions shall not exceed any limit shown in the following table:

	Emission Limit (per boiler)[d]						Total All[e] Three Boilers
	Biomass		No. 2 Oil		Bit. Coal		
Pollutant	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(TPY)
Particulate (TSP)	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Particulate (PM_{10})	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Sulfur Dioxide							
3-hour average	---	---	---	---	1.2	588.0	---
24-hour average	0.10	71.5	0.05	24.5	1.2	588.0	---
Annual average	0.02[a]	---	---	---	1.2[a]	---	1,154.3[f]
Nitrogen Oxides							
Annual average	0.15[a]	107.3[a]	0.15[a]	73.5[a]	0.17[a]	83.3[a]	862.5
Carbon Monoxide							
8-hour average	0.35	250.3	0.2	98.0	0.2	98.0	2,012.5
Volatile Organic Compounds	0.06	42.9	0.03	14.7	0.03	14.7	345.0
Lead	2.5×10^{-5}	0.018	8.9×10^{-7}	0.0004	6.4×10^{-5}	0.031	0.17
Mercury	6.3×10^{-6}[b] 0.29×10^{-6}[c]	0.0045[b] 0.00021[c]	2.4×10^{-6}	0.00118	8.4×10^{-6}	0.0041	0.0300

SPECIFIC CONDITIONS:

Beryllium	---	---	3.5×10^{-7}	0.00017	5.9×10^{-6}	0.0029	0.0052
Fluorides	---	---	6.3×10^{-6}	0.003	0.024	11.8	21.2
Sulfuric Acid Mist	0.003	2.15	0.0015	0.74	0.036	17.6	34.6

[a]Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.

[b]Emission limit for bagasse. Subject to revision after testing pursuant to Specific Conditions Nos. 24 and 25.

[c]Emission limit for wood waste. Subject to revision after testing pursuant to Specific Conditions Nos. 24 and 25.

[d]The emission limit shall be prorated when more than one type of fuel is burned in a boiler.

[e]Limit heat input from No. 2 fuel to less than 25% of total heat input on a calendar quarter basis, coal to 73,714 tons during any 12-month period, and the combination of oil and coal to less than 25% of the total heat input on a calendar quarter basis.

[f]Compliance based on a 12-month rolling average.

The permittee shall comply with the excess emissions rule contained in F.A.C. Rule 17-210.700. In addition, the permittee is allowed excess emissions during startup conditions, provided such excess emissions do not exceed a duration of four hours, and such emissions in excess of two hours do not exceed six (6) times per year.

Compliance Requirements

21. Stack Testing

a. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial startup, the permittee shall conduct emission compliance tests for all air pollutants listed in Specific Condition No. 20 (including visible emissions). Tests shall be conducted during normal operations (i.e., within 10 percent of the permitted heat input). The permittee shall furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The emission compliance tests will be conducted in accordance with the provisions of 40 CFR 60.46a.

b. Compliance with emission limitations for each fuel stated in Specific Condition No. 20 above 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

SPECIFIC CONDITIONS:

Department, in accordance with F.A.C. Rule 17-297.620. A test protocol shall be submitted for approval to the Bureau of Air Regulation at least 90 days prior to testing.

EPA Method*	For Determination of
1	Selection of sample site and velocity traverses.
2	Stack gas flow rate when converting concentrations to or from mass emission limits.
3 or 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 concentration and mass emissions.
201 or 201A	PM_{10} emissions.
6, 6C, or 19	Sulfur dioxide emissions from stationary sources.
7 or 7E	Nitrogen oxide emissions from stationary sources.
8	Sulfuric acid mist.
9	Visible emission determination of opacity. - At least three one hour runs to be conducted simultaneously with particulate testing. - At least one truck unloading into the mercury reactant storage silo (from start to finish).
10	Carbon monoxide emissions from stationary sources.
12	Determination of inorganic lead emissions from stationary sources.
13A or 13B	Fluoride emissions from stationary sources.
18 or 25	Volatile organic compounds concentration.
101A	Determination of particulate and gaseous mercury emissions.
104	Determination of beryllium emissions from stationary sources.
108	Determination of particulate and gaseous arsenic emissions.

SPECIFIC CONDITIONS:

EMTIC Test Method CTM-012.WPF	Chromium and copper emissions.

*Other approved EPA test methods may be substituted for the listed method unless the Department has adopted a specific test method for the air pollutant.

22. Emission compliance tests shall be conducted under such conditions as the Department shall specify based on representative performance of the facility. The permittee shall make available to the Department such records as may be necessary to determine the conditions of the emission compliance tests.

23. The permittee shall provide 30 days notice of the equipment performance tests or 15 working days for stack tests in order to afford the Department the opportunity to have an observer present.

24. Stack tests for particulates, NO_x, SO_2, sulfuric acid mist, CO, VOC, lead, mercury, beryllium, fluorides, arsenic, chromium, copper, and visible emissions shall be performed once every six months during the first two years of facility operation in accordance with Specific Conditions Nos. 21, 22, and 23 above. If the test results for the first two years of operation indicate the facility is operating in compliance with the terms of approval and of applicable permits and regulations, the tests will thereafter occur according to the following schedule:

-Annually for particulates, sulfur dioxide,* sulfuric acid mist,* NO_x, CO, VOC, mercury, arsenic, chromium, copper and visible emissions.
-Once every five years (at permit renewal time) for SO_2, sulfuric acid mist, lead, beryllium, and fluorides.

*Test required only during years coal is burned in the boilers.

25. After conducting the initial stack tests required under Specific Condition No. 24 above, a fuel management plan shall be submitted to the Department and Palm Beach County within 90 days specifying the fuel types and fuel quantities to be burned in the facility in order to not exceed the facility annual mercury, lead, beryllium, and fluorides emission limits specified in Condition 20

SPECIFIC CONDITIONS:

above. The plan shall include mercury emission factors based on stack testing, and may include revised mercury emission factors and baseline emission estimates for the existing Okeelanta facility.

Reporting Requirements

26. Stack monitoring, fuel usage, and fuel analysis data shall be reported to the Department's South and Southeast District Offices and to the Palm Beach County Health Unit on a quarterly basis commencing with the start of commercial operation in accordance with 40 CFR, Part 60, Sections 60.7 and 60.49a, and in accordance with Section 17-297.500, F.A.C.

27. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

28. An application for an operation permit must be submitted to the South District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Issued this 27 day
of September, 1993

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell

Virginia B. Wetherell, Secretary
Department of Environmental Protection

Best Available Control Technology (BACT) Determination
Okeelanta Power Limited Partnership
Palm Beach County
AC50-219413 (PSD-FL-196)

The applicant proposes to construct a 74.9 MW (gross), (1-hour average), electric cogeneration facility consisting of three 715 MMBtu/hr spreader-stoker boilers that will burn biomass (bagasse and wood waste material), No. 2 fuel oil, and coal. The proposed cogeneration facility will be constructed at Okeelanta Corporation's sugar mill that is located 6 miles south of South Bay, off U.S. Highway 27, Palm Beach County, Florida. During the period from initial firing to commercial operation of the cogeneration facility, both new and existing boilers can be operated simultaneously for up to 90 days while the new system is being debugged. Eight existing bagasse/No. 6 fuel oil fired boilers at the sugar mill will be shut down when the cogeneration facility begins commercial operation.

The cogeneration facility, as proposed, will cause a significant net emissions increase of sulfur dioxide, fluorides, and beryllium. Therefore, the project is subject to new source review pursuant to the Prevention of Significant Deterioration (PSD) regulations (F.A.C. Rule 17-212.400). This BACT determination is part of the PSD requirements.

Date of Receipt of a BACT Application: September 30, 1992

The BACT Determination requested by the applicant is summarized below:

Sulfur Dioxide: The recommended BACT is the use of low sulfur fuel: biomass, typically 0.009 percent sulfur; No. 2 fuel oil with a maximum of 0.05 percent sulfur, and coal with a maximum of 0.70 percent sulfur. Also, limiting the No. 2 fuel oil burned in the boilers to less than 25 percent of the heat input on a calendar quarter basis, limiting the burning of coal to 73,714 tons during any 12-month period, limiting the combined heat input from coal and oil to 25 percent of the heat input during any calendar quarter, and limiting the annual sulfur dioxide emissions to 1,154.3 TPY are conditions of the BACT determination.

Fluorides: The recommended BACT is limiting the quantity of low sulfur coal burned in the facility, the primary source of fluorides, to a maximum of 16 percent of the total annual heat input and the use of an ESP to capture particulates containing the pollutant.

Beryllium: Same as above.

A summary of the emission limits proposed by the applicant for each pollutant subject to the BACT determination follows:

Proposed Emission Limits for the Okeelanta Power Facility

Pollutants	Emission Limits (lbs per MMBtu/lbs per hr per boiler) Fuels* Biomass	No. 2 fuel oil	Coal
SO_2	0.10/71.5	0.05/24.5	1.2/588
Beryllium	--	3.5E-7/1.7E-4	5.9E-6/2.9E-3
Fluorides	--	6.3E-6/3.0E-3	2.4E-2/11.8

* Maximum heat input per boiler

Biomass - 715 MMBtu/hr
No. 2 fuel oil - 490 MMBtu/hr
Coal - 490 MMBtu/hr

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-212.410, Best Available Control Technology Determination, Stationary Source-Preconstruction Review, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to 40 CFR 52.21, and any emission limitation 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).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically

or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

BACT Determination by DEP

Pollutant	Emission Limit (lbs/MMBtu)	Control Technology	EPA Test Method
Sulfur Dioxide	0.10 (biomass) 0.02 (30-day rolling avg. on biomass) 0.05 (No. 2 fuel oil) 1.2 (coal) (30-day rolling average)	Low sulfur fuel (0.05 percent max. for No. 2 fuel oil; 0.70 percent max. for coal; max. heat input of less than 25 percent on a calendar quarter basis from No. 2 fuel oil, a max. of 73,714 tons coal burned during any 12-month period, a max. combined heat input for coal and oil of less than 25 percent on a calendar quarter basis, and limiting sulfur dioxide emissions to 1,154.3 TPY 12-month rolling average	6, 6C, or 19 and continuous emissions monitoring.
Beryllium	3.5E-7 (No. 2 fuel oil) 5.9E-6 (coal)	Max. heat input of less than 25 percent from No. 2 fuel oil, on a calendar quarter basis, max. annual capacity factor of 16 percent for coal, a max. heat input of less than 25 percent on a calendar quarter basis for combined coal and oil, and use of an ESP	104

Fluorides	6.3E-6 (No. 2 fuel oil) 2.4E-2 (coal)	Max. heat input of less than 25 percent on a calendar quarter basis from No. 2 fuel oil, max, annual capacity factor of 16 percent for coal, a max. combined heat input of less than 25 percent on a calendar quarter basis for coal and oil, and use of an ESP	13A or 13B

BACT Determination Rationale

Sulfur Dioxide: The proposed facility is subject to PSD because of the potential emissions of the alternate coal fuel. The coal will contain a maximum of 0.70 percent sulfur. The applicant proposes that the heat input from fossil fuels be limited to less than 25 percent of the total heat input on a calendar quarter basis for the boilers. Thus, 75 percent of the heat input (minimum) for the boilers will be provided by biomass -- a fuel that averages 0.009 percent sulfur. The highest proposed SO_2 emissions, 1.2 lbs/MMBtu heat input and 1,154 TPY, will occur when 16 percent of the annual heat input is provided by coal containing 0.7 percent sulfur. These emissions meet the applicable new source performance standards, 40 CFR 60, Subpart Da. The use of either a wet limestone scrubber or lime/sodium spray dry scrubber, controls used in other BACT determinations listed in the BACT/LAER Clearinghouse document, would reduce SO_2 emissions significantly (over 90 percent). The scrubbers would also create a contaminated liquid or dry solid waste which would have to be disposed of properly. The applicant evaluated the economic, energy and environmental impacts of wet scrubbers, dry scrubbers and dry injection system, in combination with low, medium and high sulfur coal, as technically feasible control alternatives. The economic analysis estimated the total cost effectiveness over baseline of these alternatives to range from $4,994 to $8,923 per ton of SO_2 removed. Limiting the use of low sulfur coal to a 16 percent capacity factor and total sulfur dioxide emissions from the facility, instead of requiring a flue gas desulfurization system, is consistent with recent BACT determinations for multi-fuel spreader stoker boilers. This is applicable to Okeelanta Power because the coal will be fired on an infrequent and intermittent basis. The weighted average sulfur dioxide emissions from this facility will be 0.21 lbs/MMBtu. The combined sulfur dioxide emissions from Okeelanta Power and Osceola Power, a similar proposed plant whose application is being processed at this time, is 1,507 TPY. This results in an overall

sulfur dioxide emission limit of 0.168 lbs/MMBtu for both facilities. This average emission rate is close to that determined as BACT for 100 percent coal-fired power plants (i.e., 0.17 lbs/MMBtu for Bechtel Indiantown and 0.25 lbs/MMBtu for OUC Stanton Unit 2).

The ambient air impact for SO_2 at the proposed emission rate has been calculated to be 0.8, 74, and 164 ug/m^3 for the annual, 24-hour, and 3-hour time periods, respectively.

Beryllium: Traces of beryllium are present in fossil fuels. Beryllium can be vaporized and emitted as an air pollutant when these fuels are burned. At the operating temperature of the ESP, approximately 350°F, most of the beryllium should be condensed and captured by the 98 percent efficient ESP. Maximum beryllium emissions are estimated to be 8.7E-3 lbs/hr. The ambient air impact of this emission will be 5E-4, 4E-4, and 3E-5 ug/m^3 for the 8-hour, 24-hour and annual time periods, respectively. These impacts are below the Acceptable Ambient Concentration (AAC), a concentration believed to have an acceptable health risk to the public.

Fluorides: The fluorides in the fuels can be converted to acid gases during combustion. A majority of these pollutants at Okeelanta Power will come from the coal burned at that facility. By limiting the heat input from coal to a 16% capacity factor, acid gases (fluorides) will be limited. Any acid gas existing in a liquid or solid phase can be captured by the ESP.

At a maximum emission rate per boiler of 11.8 lbs/hr fluorides, the 8-hour and 24-hour impacts are 1.95 and 1.48 ug/m^3. These impacts are below the AAC.

The Department concluded that limitations on the amount of fossil fuel burned at this facility is BACT for these pollutants.

Conclusion

For the emission standards established as BACT, the ambient air impacts of the sulfur dioxide, beryllium, and fluorides will be below the ambient air standards and/or AAC for these pollutants.

Details of the Analysis May be Obtained by Contacting:
Doug Outlaw, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

September 17 1993
Date

Approved by:

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

September 27 1993
Date

Reasonably Available Control Technology (RACT) Determination
Okeelanta Power Limited Partnership
Palm Beach County
AC50-219413 (PSD-FL-196)

The applicant proposed to construct a 74.9 MW (gross, 1-hour average), electric cogeneration facility consisting of three 715 MMBtu/hr spreader-stoker boilers that will burn biomass (bagasse and wood waste material), No. 2 fuel oil, and coal. The proposed cogeneration facility will be constructed at and its operations integrated into Okeelanta Corporation's sugar mill. This mill is located 6 miles south of South Bay, Palm Beach County, Florida. Eight existing bagasse/No. 6 fuel oil boilers at the sugar mill will be replaced by the cogeneration facility when it begins commercial operation. The cogeneration facility is a major source for volatile organic compounds (345 TPY) and nitrogen oxides (862.5 TPY). However, the net contemporaneous emission change for these pollutants resulting from the cogeneration facility project, a reduction of 56.9 TPY for VOC and a reduction of 26.2 TPY for NO_X, is less than the significant emission rates, Table 212.400-2, F.A.C. Thus, the project is subject to F.A.C. Rule 17-296.570, Reasonably Available Control Technology (RACT) Requirements for Major VOC - and NO_X - Emitting Facilities.

Date of Receipt of an Application Subject to RACT: Sept. 30, 1992.

The RACT Determination requested by the applicant is summarized below:

Volatile Organic Compounds: The recommended VOC air pollution control is efficient boiler design and good combustion practices based on the document titled "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls." The estimated VOC emission rates are 0.06 lbs/MMBtu on biomass and 0.03 lbs/MMBtu on No. 2 fuel oil and coal.

Nitrogen Oxides: The recommended NO_X air pollution control is use of a selective non-catalytic reduction system designed to achieve at least 40 percent NO_X reduction efficiency. The estimated NO_X emission rates are 0.15 lbs/MMBtu for biomass fuels and No. 2 fuel oil and 0.17 lbs/MMBtu for coal firing.

RACT Determination Procedure

In accordance with F.A.C. Rule 17-296.570, Reasonably Available Control Technology (RACT) Requirements for Major VOC - and NO_X - Emitting Facilities, this RACT determination is based on the applicant's proposal, published documents, and technological feasibility.

RACT Determined by DEP

Fuel	VOC lbs/MMBtu	VOC Control	NO_x lbs/MMBtu	NO_x Control
Biomass	0.06	Boiler Design, Good operation practice using the oxygen meter	0.15	Non-Catalytic reduction system
No. 2 Fuel Oil	0.03		0.15	
Coal	0.03		0.17	

RACT Determination Rationale

VOC: The applicant is committed to meeting the VOC emission limit through good design and operating practice based on a procedure that has been considered as a BACT determination for similar boilers. As a BACT determination is generally considered to establish more stringent emission standards than a RACT determination, the Department finds the applicant's proposal acceptable.

NO_x: The applicant will use a selective non-catalytic reduction system to lower NO_x emissions. The proposed NO_x emissions are lower than the limits given in the new source performance standards (NSPS) for electric utility steam generation units (40 CFR 60, Subpart Da). As a NSPS is generally considered to have a more stringent emission limit than a RACT standard, the Department finds the applicant's proposal acceptable.

There is a net reduction in the VOC and NO_x emissions from the Okeelanta Power Limited Partnership project. Therefore, the ambient air impact of these pollutants from the Okeelanta Corporation's sugar mill will decrease.

Conclusion

Good boiler design, operation practice and use of a non-catalytic reduction system meets the VOC and NO_x RACT for the proposed cogeneration facility. The emissions will not interfere with reasonable further progress in this ozone non-attainment area.

Details of the Analysis May be Obtained by Contacting:

Doug Outlaw, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

September 17 1993
Date

Approved by:

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

September 27 1993
Date

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

Notice of Permit Amendment

In the Matter of an
Application for Permit Amendment

DEP File No. AC 50-219413
PSD-FL-196
County: Palm Beach

Mr. Dennis V. Space, General Manager
Okeelanta Power Limited Partnership
Post Office Box 8
South Bay, Florida 33493

Enclosed is a letter that amends Permit Number AC50-219413/PSD-FL-196. The amendment authorizes additional time for simultaneous operation of the existing bagasse boilers at the adjacent sugar mill and the new biomass cogeneration boilers while technical problems with the new boilers and bagasse feed systems are being corrected. This permit amendment is issued pursuant to Section 403, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000, and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 14 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this NOTICE OF PERMIT AMENDMENT and all copies were mailed before the close of business on 6-14-96 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Clerk

6-14-96
Date

Copies furnished to:

David Knowles, SD
James Stormer, PBCHU
John Bunyak, NPS
David Dee, Landers & Parsons
Isidore Goldman, SED
Jewell Harper, EPA
David Buff, KBN

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

June 12, 1996

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Dennis V. Space, General Manager
Okeelanta Power Limited Partnership
Post Office Box 8
South Bay, Florida 33493

Dear Mr. Space:

Re: Amendment of Permit
AC 50-219413/PSD-FL-196

The Department has reviewed your April 17 letter requesting that the referenced permit be amended to allow additional time for the simultaneous operation of Okeelanta Corporation's existing sugar mill bagasse boilers and the new cogeneration boilers at the facilities located near South Bay, Palm Beach County, Florida. This request is acceptable and the referenced permit is amended as follows:

FROM:

17. During the first three years of commercial cogeneration facility operation, the existing Boilers Nos. 4, 5, 6, 10, 11, 12, 14, and 15 (Permit Nos. AO 50-169210, 190690, 175414, 190693, 175411, 169215, 189904, and 209094, respectively) may be retained for standby operation. During the period from initial firing to commercial operation, all three cogeneration boilers can be operated simultaneously with the existing boilers. Only biomass and No. 2 fuel oil may be used in the cogeneration boilers during this period. If more than 910,836 lb/hr steam is generated in the cogeneration boilers, steam in excess of 910,836 lb/hr must be sent to the Okeelanta sugar mill, and the existing boiler's steam production reduced by an equivalent amount. This period shall not exceed a total duration of 12 months. During this 12-month period, simultaneous operation of the existing boilers and the cogeneration boilers shall not occur on more than a total of 90 calendar days. After the first year of cogeneration facility operation, the existing boilers may be operated only when all three cogeneration

boilers are shutdown. During operation, the existing boilers must meet all requirements in the most recent construction and operation permits for the boilers. These existing boilers shall be shutdown and rendered incapable of operation within three (3) years of commercial startup of the cogeneration facility, but no later than January 1, 1999.

18. Boiler No. 16 (AC 50-191876) may be retained as a standby boiler for the cogeneration facility provided its permit is amended to authorize standby use. Boiler No. 16 may be operated during initial startup, debugging, and testing of the cogeneration facility for a period not to exceed 12 months following initial firing of fuel in the new boilers. After the first year of cogeneration operation, this boiler may be operated only when one or more of the three cogeneration boilers are shutdown. During operation, this boiler must meet all requirements in the current construction or operating permit for the boiler.

TO:

17. During the first three years of commercial cogeneration facility operation, the existing Boilers Nos. 4, 5, 6, 10, 11, 12, 14, and 15 (Permit Nos. AO 50-169210, 190690, 175414, 190693, 175411, 169215, 189904, and 209094, respectively) may be retained for standby operation. During the period from initial firing **until April 1, 1997**, all three cogeneration boilers can be operated simultaneously with the existing boilers. Only biomass and No. 2 fuel oil may be used in the cogeneration boilers during periods **of simultaneous operation.** If more than 910,836 lb/hr steam is generated in the cogeneration boilers, steam in excess of 910,836 lb/hr must be sent to the Okeelanta sugar mill, and the existing boiler's steam production reduced by an equivalent amount. After **April 1, 1997,** the **cogeneration** boilers may be operated only when **the existing sugar mill** boilers are shutdown **or in the process of immediately shutting down.** During operation, the existing boilers must meet all requirements in the most recent construction and operation permits for the boilers. These existing boilers shall be shutdown and rendered incapable of operation within three (3) years of commercial startup of the cogeneration facility, but no later than January 1, 1999.

18. Boiler No. 16 (AC 50-191876) may be retained as a standby boiler for the cogeneration facility provided its permit is amended to authorize standby use. Boiler No. 16 may be operated during startup, debugging, and testing of the cogeneration facility. After

April 1, 1997, this boiler may be operated only when one or more of the three cogeneration boilers are shutdown. During operation, this boiler must meet all requirements in the current construction or operating permit for the boiler.

A copy of this letter shall be attached to the referenced permit and shall become a condition of that permit.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Howard L. Rhodes, Director
Division of Air Resources Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that all copies of this INTENT TO ISSUE PERMIT AMENDMENT all copies were mailed by certified mail before the close of business on 6-14-96 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Kyri Jobes 6-14-96
Clerk Date

HLR/wh/t

Attachment: Okeelanta Power L.P. April 17, 1996 letter

Copies furnished to:

David Knowles, SD
Isidore Goldman, SED
James Stormer, PBCHD
Jewell Harper, EPA
John Bunyak, NPS
David Buff, KBN
David Dee, Landers & Parsons

December 22, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ricardo Lima, Vice President and General Manager
Okeelanta Power L.P.
P.O. Box 86
South Bay, FL 33493

Re: DEP File No. 0990332-012-AC, Request to Install Pre-Control Equipment
Okeelanta Power L.P. - Cogeneration Plant
(PSD Permit No. PSD-FL-196)
ARMS Facility ID No. 0990332

Dear Mr. Lima:

Okeelanta Power L.P. operates a biomass cogeneration plant located near South Bay in Palm Beach County, Florida. On September 7, 1999, Okeelanta Power L.P. applied to the Department for a minor permit modification to install cyclone dust collectors as pre-control devices prior to the electrostatic precipitators (ESPs). The proposed equipment is intended to remove large particulate matter, which will reduce particulate loading to the electrostatic precipitator and enhance the overall control efficiency. The Department received the final design information on December 16, 1999 and approves the request. In consideration of improving the performance of the existing electrostatic precipitators and because the proposed equipment is expected to reduce particulate emissions, the Department authorizes the applicant to immediately install the following equipment (or equivalent) prior to the electrostatic precipitator for each biomass cogeneration boiler:

Manufacturer: Barron Industries
Model: 460 Tube Barron Base III 9K15-2023-AU
Description: Four module, large diameter, multitube mechanical dust collector with airfoil vanes
Tube Specifications: Cast hard gray iron Base III tube with 9 inch diameter, 460 tubes
Casing, Hopper, and Tube Sheet Materials: Carbon steel
Hoppers: Four through hoppers with internal screw conveyor
Design Flue Gas Conditions: 450°F; 359,506 acfm; dust specific gravity is between 1.00 and 2.00
Design Pressure Drop: 2.8 inches of water column
Overall Design Collection Efficiency: > 85% efficiency for particles greater than PM_{10} (SG = 2.00)

The Department is also processing a request from Okeelanta Power L.P. to extend standby operation of the bagasse boilers at Okeelanta Corporation's existing sugar mill (DEP File No. 0990332-011-AC). As previously discussed, the Department will include requirements to install, operate, and maintain the mechanical dust collectors as part of this proposed modification, which will require the publishing of a Public Notice making these federally enforceable. Please file a copy of this letter authorizing construction with the referenced permit.

Sincerely,

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

Mr. Ricardo Lima, Okeelanta Power L.P.*
Mr. James Meriwether, Okeelanta Power L.P.
Mr. David Buff, Golder Associates
Mr. James Stormer, Palm Beach County Health Department
Mr. David Knowles, South District Office DEP
Gregg Worley, EPA Region 4

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

NOTICE OF PERMIT AMENDMENT

In the matter of an
Application for Permit Amendment by:

DEP File No. AC50-219413
PSD-FL-196(A)

Mr. Dennis Space, Project Director
Okeelanta Power Limited Partnership
Post Office Box 117
South Bay, Florida 33493

Enclosed is amended permit No. AC50-219413, PSD-FL-196(A) which will include a federally-enforceable condition limiting the amount of yard trash which may be burned at Okeelanta's cogeneration facility in South Bay, Florida. This permit amendment is issued pursuant to Section 403, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 14 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this **NOTICE OF PERMIT AMENDMENT** and all copies were mailed by certified mail before the close of business on 3-26-96 to the listed persons.

Clerk Stamp
FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Clerk

3-26-96
Date

Copies furnished to:

David Knowles, SD
Isidore Goldman, SED
James Stormer, PBCHD
Jewell Harper, EPA
John Bunyak, EPA

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

February 19, 1996

CERTIFIED MAIL RETURN - RECEIPT REQUESTED

Mr. Dennis Space
Project Director
Okeelanta Power Limited Partnership
Post Office Box 117
South Bay, Florida 33493

Dear Mr. Space:

RE: Okeelanta Cogeneration Facility
PSD-FL-196; AC50-219413

We are in receipt of your letters dated September 22 and November 9, 1995 requesting amendment of the referenced permit to subject the facility to a federally enforceable condition limiting the amount of material burned which can be construed as municipal-type solid waste (MSW).

The Department has evaluated your proposal and approved your request. The permit is revised to include the following new Specific Condition identified as 12A.

SPECIFIC CONDITION 12A:

Each boiler (co-fired combustor) is limited to combusting a fuel stream, 30 percent or less of the weight of which is comprised, in aggregate, of yard waste (yard trash) defined as a municipal solid waste (MSW) in 40 CFR 60.51a, as measured on a calendar quarter basis. This facility must comply with any applicable requirements in 40 CFR 60 Subpart Ea.

A copy of this amendment letter shall be attached to and shall become a part of Air Construction Permits AC50-219413 and PSD-FL-196.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/th/t

Enclosures

cc: Jewell Harper, EPA
John Bunyak, NPS
David Knowles,SD
Isidore Goldman, SED
James Stormer, PBCHD

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

May 1, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Dennis V. Space, General Manager
Okeelanta Power Limited Partnership
Post Office Box 8
South Bay, Florida 33493

Re: FINAL Permit Modification No. 0990332-005-AC
PSD-FL-196C

Dear Mr. Space:

The Department has reviewed Okeelanta Power's February 28 letter requesting a modification to its permit to allow additional time for the simultaneous operation of Okeelanta's existing sugar mill boilers and your new cogeneration boilers at the facilities located near South Bay, Palm Beach County, Florida. This request is acceptable and your permit is hereby amended as follows:

SPECIFIC CONDITION FOR OKEELANTA POWER LIMITED PARTNERSHIP PERMIT

FROM:

17. During the first three years of commercial cogeneration facility operation, the existing Boilers Nos. 4, 5, 6, 10, 11, 12, 14, and 15 (Permit Nos. AO50-169210, 190690, 175414, 190693, 175411, 169215, 189904, and 209094, respectively) may be retained for standby operation. During the period from initial firing until April 1, 1997, all three cogeneration boilers can be operated simultaneously with the existing boilers. Only biomass and No. 2 fuel oil may be used in the cogeneration boilers during periods of simultaneous operation. If more than 910,836 lb/hr steam is generated in the cogeneration boilers, steam in excess of 910,836 lb/hr must be sent to the Okeelanta sugar mill, and the existing boiler's steam production reduced by an equivalent amount. After April 1, 1997, the cogeneration boilers may be operated only when the existing sugar mill boilers are shutdown or in the process of immediately shutting down. During operation, the existing boilers must meet all requirements in the most recent construction and operation permits for the boilers. These existing sugar mill boilers shall be shutdown and rendered incapable of operation within three (3) years of commercial startup of the cogeneration facility, but no later than January 1, 1999.

18. Boiler No. 16 (AC50-191876) may be retained as a standby boiler for the cogeneration facility provided its permit is amended to authorize standby use. Boiler No. 16 may be operated during startup, debugging, and testing of the cogeneration facility. After April 1, 1997, this boiler may be operated only when one or more of the three cogeneration boilers are shutdown. During operation, this boiler must meet all requirements in the current construction or operating permit for the boiler.

TO:

17. During the first three years of commercial cogeneration facility operation, the existing Boilers Nos. 4, 5, 6, 10, 11, 12, 14, and 15 (Permit Nos. AO50-169210, 190690, 175414, 190693, 175411, 169215, 189904, and 209094, respectively) may be retained for standby operation. During the period from initial firing until April 1, **1998** all three cogeneration boilers can be operated simultaneously with the existing boilers. Only biomass and No. 2 fuel oil may be used in the cogeneration boilers during periods of simultaneous operation. If more than 910,836 lb/hr steam is generated in the cogeneration boilers, steam in excess of 910,836 lb/hr must be sent to the Okeelanta sugar mill, and the existing boiler's steam production reduced by an equivalent amount. After April 1, **1998** the cogeneration boilers may be operated only when the existing sugar mill boilers are shutdown or in the process of immediately shutting down. During operation, the existing sugar mill boilers must meet all requirements in the most recent construction and operation permits for the boilers. These existing boilers shall be shutdown and rendered incapable of operation within three (3) years of commercial startup of the cogeneration facility, but no later than January 1, 1999.

18. Boiler No. 16 (AC50-191876) may be retained as a standby boiler for the sugar refinery and sugar mill in accordance with its existing permit. Boiler No. 16 may be operated during startup, debugging, and testing of the cogeneration facility. After April 1, **1998** this boiler may be operated only when one or more of the three cogeneration boilers are shutdown. During operation, this boiler must meet all requirements in the current construction or operating permit for the boiler.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/wh/t

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT MODIFICATION

In the Matter of an
Application for Permit Modification

Mr. Dennis V. Space, General Manager
Okeelanta Power Limited Partnership
Post Office Box 8
South Bay, Florida 33493

DEP File No.0990332-005-AC
PSD-FL-196C

Enclosed is a letter that amends Permit Number PSD-FL-197B. This letter modifies the construction permit for Okeelanta Power's cogeneration facility to allow additional time for concurrent operation of the Okeelanta sugar mill's existing boilers and the new cogeneration boilers while problems with the interconnections between the plants are being resolved. This permit amendment is issued pursuant to Section 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT MODIFICATION (including the FINAL permit modification) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5-5-97 to the person(s) listed:

Dennis Space, Okeelanta Power L.P.*
David Knowles, SD
Isidore Goldman, SED
James Stormer, PBCHD

Brian Beals, EPA
John Bunyak, NPS
David Buff, Golder Associates
David Dee, Landers & Parsons

Clerk Stamp

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

Kyra Faber 5-5-97
(Clerk) (Date)

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT AMENDMENT

In the Matter of an
Application for Permit Amendment

Mr. Dennis Space, General Manager
Okeelanta Power Limited Partnership
Post Office Box 8
South Bay, Florida 33493

DEP File No. 0990332-004-AC
PSD-FL-196D

Enclosed is a letter that amends Permit Number PSD-FL-196C. This letter amends the construction permit for Okeelanta Power's cogeneration facility to specify another procedure to show compliance with the sulfuric acid mist emission standard.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

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 NOTICE OF FINAL PERMIT AMENDMENT (including the FINAL permit amendment) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 4/18/97 to the person(s) listed:

Mr. Dennis Space, Okeelanta Power L.P.*
David Knowles, SE
Isidore Goldman, SED
James Stormer, PBCPHU
Brian Beals, EPA
John Bunyak, NPS
David Buff, Golder Associates
David Dee, Landers & Parsons

Clerk Stamp

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

Charlotte Hayes (Clerk) 4/18/97 (Date)

FLORIDA

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

April 16, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Dennis V. Space, General Manager
Okeelanta Power Limited Partnership
Post Office Box 8
South Bay, Florida 33493

Re: FINAL Permit Modification No. 0990332-004-AC
PSD-FL-106D

Dear Mr. Space:

The Department has reviewed Osceola Power's December 5, 1996 and March 25, 1997 letters requesting that the sulfuric acid mist emission standard and EPA Method 8 testing requirement be removed from the construction permit for your new cogeneration boilers located near South Bay in Palm Beach County.

In response to this request, the Department is retaining the sulfuric acid mist emission standard and adopting the modified Method 8 test procedure as described in the memorandum of December 19, 1995 from Jim Wright of Clean Air Engineering to Michelle Griffin. The permit is hereby amended as follows:

Specific Condition No. 21.b.

From:

EPA Method *	For Determination of
8	Sulfuric Acid Mist

To:

EPA Method *	For Determination of
8 (modified) **	Sulfuric Acid Mist

** As described in Clean Air Engineering memo dated December 19, 1995, Wright to Griffin

A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/wh/t

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

RECEIVED
MAY 13 1997
OPLP

April 16, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Dennis V. Space, General Manager
Okeelanta Power Limited Partnership
Post Office Box 8
South Bay, Florida 33493

Re: FINAL Permit Modification No. 0990332-004-AC
PSD-FL-196D

Dear Mr. Space:

The Department has reviewed Okeelanta Power's December 5, 1996 and March 25, 1997 letters requesting that the sulfuric acid mist emission standard and EPA Method 8 testing requirement be removed from the construction permit for your new cogeneration boilers located near South Bay in Palm Beach County.

In response to this request, the Department is retaining the sulfuric acid mist emission standard and adopting the modified Method 8 test procedure as described in the memorandum of December 19, 1995 from Jim Wright of Clean Air Engineering to Michelle Griffin. The permit is hereby amended as follows:

Specific Condition No. 20.b.

From:

EPA Method *	For Determination of
8	Sulfuric Acid Mist

To:

EPA Method *	For Determination of
8 (modified) **	Sulfuric Acid Mist

** As described in Clean Air Engineering memo dated December 19, 1995, Wright to Griffin

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

October 24, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. James T. Carlton
Authorized Representative
Okeelanta Power Limited Partnership
Post Office Box 8
South Bay, Florida 33493

Re: Permit Modification No. 0990332-006-AC (PSD-FL-196)
74.9 Megawatt Cogeneration Facility

Dear Mr. Carlton:

The Department has reviewed your application dated May 5, 1997 to modify the original construction permit for the Okeelanta Cogeneration Facility. The application is to revise emission limits for carbon monoxide (CO), lead (Pb), mercury (Hg), and sulfur dioxide (SO_2). Construction permit No. AC50-219413 (PSD-FL-196) is hereby modified as follows:

SPECIFIC CONDITIONS NO. 15.

The consumption of No. 2 fuel oil shall be less than 25 percent of the total heat input to each boiler unit in any calendar quarter. Not more than ~~73,714~~ 69,720 tons of coal shall be burned at this facility during any 12-month period. The combined heat input for coal and oil shall be less than 25 percent of the heat input on a calendar quarter basis.

SPECIFIC CONDITION NO. 16.

The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, beryllium content (coal only), sulfur content, and equivalent SO_2 emission rate (in lbs/MMBtu) of each fuel oil and coal delivery shall be kept in a log for at least two years. For each calendar month, the calculated SO_2, mercury, and lead emissions and 12-month rolling average shall be determined (in tons) and kept in a log.

SPECIFIC CONDITION NO. 20.

Visible emissions from any boiler shall not exceed 20 percent opacity, 6-minute average, except up to 27 percent opacity is allowed for up to 6 minutes in any 1-hour period. Based on a maximum heat input to each boiler of 715 MMBtu/hr for biomass fuels and 490 MMBtu/hr for No. 2 fuel oil and coal, stack emissions shall not exceed any limit shown in the following table:

Pollutant	EMISSION LIMIT (per boiler) [d] Biomass (lb/MMBtu)	Biomass (lb/hr)	No. 2 Oil (lb/MMBtu)	No. 2 Oil (lb/hr)	Bit. Coal (lb/MMBtu)	Bit. Coal (lb/hr)	Total [e] Three Boilers (TPY)
Particulate (TSP)	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Particulate (PM_{10})	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Sulfur Dioxide							
3-hour average					1.2	588.0	
24-hour average	0.10	71.5	0.05	24.5	1.2	588.0	
Annual Average	~~0.02 a~~				1.2 a		1,154.3 f
Bagasse	0.02 a						
Wood Waste	0.05a c						
Nitrogen Oxides							
Annual average	0.15 a	107.3 a	0.15 a	73.5 a	0.17 a	83.3 a	862.5
Carbon Monoxide							
824-hour average	0.35	250.3	~~0.2~~ 0.35	~~98.0~~ 171.5	~~0.2~~ 0.35	~~98.0~~ 171.5	2,012.5
Volatile Organic Compounds	0.06	42.9	0.03	14.7	0.03	14.7	345
Lead	~~2.5 x 10 -5~~	~~0.018~~	8.9 x 10 -7	0.0004	6.4 x 10 -5	0.031	~~0.17~~ 0.454f
Bagasse	2.5 x 10 -5	0.018					
Wood Waste	1.6x10-4c	0.114c					
Mercury			2.4 x 10 -6	0.00118	8.4 x 10 -6	0.0041	0.0300f
Bagasse	~~6.3 x 10 -6~~ 5.43 x 10-6b	~~0.0045 b~~ 0.0039 b					
Wood Waste	~~0.29 x 10 -6 c~~ 4.0 x 10-6 c	~~0.00021 c~~ 0.0029 c					
Beryllium			3.5 x 10 -7	0.00017	5.9 x 10 -6	0.0029	0.0052
Fluorides			6.3 x 10 -6	0.0003	0.024	11.8	21.2
Sulfuric Acid Mist	0.003	2.15	0.0015	0.74	0.036	17.6	34.6

[a] Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.

[b] Emission limit for bagasse. Subject to revision after testing pursuant to Specific Conditions Nos. 24 and 25.

[c] Emission limit for wood waste. Subject to revision after testing pursuant to Specific Conditions Nos. 24 and 25.

[d] The emission limit shall be prorated when more than one type of fuel is burned in a boiler.

[e] Limit heat input from No. 2 fuel to less than ~~25%~~ 24.9 of total heat input on a calendar quarter basis, coal to ~~73,714~~ 69,720 tons during any 12-month period, and the combination of oil and coal to less than ~~25%~~ 24.9 of the total heat input on a calendar quarter basis.

[f] Compliance based on a 12-month rolling average for any fuel combination.

The permittee shall comply with the excess emissions rule contained in Rule 62-296.210, F.A.C. In addition, the permittee is allowed excess emissions during startup conditions, provided such excess emissions do not exceed a duration of four hours, and such emissions in excess of two hours do not exceed six (6) times per year.

SPECIFIC CONDITION NO. 21.

a. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial startup, the permittee shall conduct emission compliance tests for all air pollutants listed in Specific Condition No. 20 (including visible emissions). Test shall be conducted during normal operations (i.e., within 10 percent of the heat input). The permittee shall furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The performance tests will be conducted in accordance with the provisions of 40 CFR 60.46a.

b. Compliance with emission limitations for each fuel stated in Specific Condition No. 20 above shall be demonstrated using EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), continuous emissions monitoring data, or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), or any other method as approved by the Department, in accordance with F.A.C. Rule 62-297.620. A test protocol shall be submitted for approval to the Bureau of Air Regulation at least 90 days prior to testing.

EPA Method*	For Determination of
1	Selection of sample site and velocity traverses.
2	Stack gas flow rate when converting concentrations to or from mass emission limits.
3 or 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 concentration and mass emissions.
201 or 201A	PM_{10} emissions.
6, 6C, or 19	Sulfur dioxide emissions from stationary sources.
7, or 7E	Nitrogen oxide emissions from stationary sources.
8 (modified)	Sulfuric acid mist. **
9	Visible emission determination of opacity. - At least three one hour runs to be conducted simultaneously with particulate testing. - At least one truck unloading into the mercury reactant storage silo (from start to finish).
10	Carbon monoxide emissions from stationary sources.
12	Determination of inorganic lead emissions from stationary sources.
13A or 13B	Fluoride emissions from stationary sources.
18 or 25	Volatile organic compounds concentration.
101A	Determination of particulate and gaseous mercury emissions.
104	Determination of beryllium emissions from stationary sources.
108	Determination of particulate and gaseous arsenic emissions.
EMTIC Test Method CTM-012.WPF	Chromium and copper emissions.

* Other approved EPA test methods may be substituted for the listed method unless the Department has adopted a specific test method for the air pollutant.

** Test for sulfuric acid mist only required when coal is burned at the facility.

A copy of this permit modification shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes. Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT MODIFICATION (including the FINAL permit Modification) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10-24-97 to the person(s) listed:

Mr. James T. Carlton, Okeelanta Power L.P. *
Mr. Daniel Thompson, Berger Davis & Singerman *
Mr. David Buff, Golder Associates
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. David Knowles, SD
Mr. James Koerner, PBCPHU

Clerk Stamp

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

Kuni Tober (Clerk) 10-24-97 (Date)

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

June 22, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. James Meriwether
Environmental Manager
Okeelanta Cogeneration Facility
Post Office Box 9
South Bay, Florida 33493

RE: DEP File No. 0990332-010-AC (PSD-FL-196F)
Permit Modifications

Dear Mr. Meriwether:

This is in response to Golder Associates' letter dated December 14, 1998 and fee received February 2, 1999 requesting changes to the subject construction permit. The Department considered the requests and agrees to modify the permit conditions as indicated below. The request for revising the 0.35 lb CO/MMBtu limit from a 24-hour averaging time to a 30-day rolling average was approved. However, the requested increase to 0.5 lb CO/MMBtu was not granted based on our conclusion from the test data that the longer term average can be met at 0.35 lb/MMBtu. The requested modifications of provisions related to excess emissions and other changes are indicated by the <u>underlined</u> additions.

The permit is hereby modified as shown below. The excess fee paid will be refunded separately.

SPECIFIC CONDITION NO. 20

Visible emissions from any boiler shall not exceed 20 percent opacity, 6-minute average, except up to 27 percent opacity is allowed for up to 6 minutes in any 1-hour period. Based on a maximum heat input to each boiler of 715 MMBtu/hr for biomass fuels and 490 MMBtu/hr for No. 2 fuel oil and coal, stack emissions shall not exceed any limit shown in the following table:

	EMISSION LIMIT (per boiler) [d]						Total [e] Three Boilers
	Biomass		No. 2 Oil		Bit. Coal		
Pollutant	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(TPY)
Particulate (TSP)	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Particulate (PM_{10})	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Sulfur Dioxide							
3-hour average					1.2	588.0	
24-hour average	0.10	71.5	0.05	24.5	1.2	588.0	
Annual Average							
(Bagasse)	0.02 a				1.2 a		1,154.3 f
(Wood Waste)	0.05a c						
Nitrogen Oxides							
Annual average	0.15 a	107.3 a	0.15 a	73.5 a	0.17 a	83.3 a	862.5

Carbon Monoxide ~~24-hour~~ 30-day rolling avg.	0.35 a	250.3 a	0.35 a	171.5 a	0.35 a	171.5 a	2,012.5
Volatile Organic Compounds	0.06	42.9	0.03	14.7	0.03	14.7	345
Lead (Bagasse)	2.5×10^{-5} b	0.018 b	8.9×10^{-7}	0.0004	6.4×10^{-5}	0.031	0.454 f
" (Wood Waste)	1.6×10^{-4} c	0.114 c					
Mercury (Bagasse)	5.43×10^{-6} b	0.0039 b	2.4×10^{-6}	0.00118	8.4×10^{-6}	0.0041	0.0300 f
" (Wood Waste)	4.0×10^{-6} c	0.0029 c					
Beryllium	---	---	3.5×10^{-7}	0.00017	5.9×10^{-6}	0.0029	0.0052
Fluorides	---	---	6.3×10^{-6}	0.0003	0.024	11.8	21.2
Sulfuric Acid Mist	0.003	2.15	0.0015	0.74	0.036	17.6	34.6

Table Notes:

a Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.

[CO Limit: Although carbon monoxide (CO) emissions are not regulated by NSPS Subpart Da, compliance shall be demonstrated in a similar manner. The CO emissions from each boiler shall not exceed 0.35 pounds per MMBTU based on a 30-day (boiler operating days) rolling average. Compliance with this standard shall be demonstrated by continuous emissions monitoring data. The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days. The 1-hour averages shall be expressed in lb/MMBTU of heat input and are calculated using at least two valid data points. Calculation of the 30-day rolling average shall consist of at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the permittee shall supplement emission data with other monitoring systems approved by the EPA Administrator or the reference methods and procedures as described in 40 CFR 60.47a.]

b Emission limit for bagasse. Subject to revision after testing pursuant to Specific Condition Nos. 24 and 25.

c Emission limit for wood waste. Subject to revision after testing pursuant to Specific Condition Nos. 24 and 25.

d The emission limit shall be prorated when more than one type of fuel is burned in a boiler.

e Limit heat input from No. 2 fuel to less than 24.9 of total heat input on a calendar quarter basis, coal to 69,720 tons during any 12-month period, and the combination of oil and coal to less than 24.9 of the total heat input on a calendar quarter basis.

f Compliance based on a 12-month rolling average for any fuel combination.

The permittee shall comply with the excess emissions rule contained in Rule 62-210.700, F.A.C. In addition, the permittee is allowed excess emissions during startup, ~~and~~ shutdown and malfunction in accordance with permit condition No. 21, ~~provided such excess emissions do not exceed a duration of four hours, and such emissions in excess of two hours do not exceed six (6) times per year.~~ Periods of startup, shutdown and malfunction shall be defined as:

a. *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.

b. *Shutdown* is the cessation of the operation of a boiler for any purpose after steam generation drops below 150,000 pounds per hour.

c. 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 (179), (258), (275), F.A.C. and Rule 62-4.070(3), F.A.C.]

SPECIFIC CONDITION NO. 21

a. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial startup, the permittee shall conduct emission compliance tests for all air pollutants listed in Specific Condition No. 20 (including visible emissions). Test shall be conducted during normal operations (i.e., within 10 percent of the heat input). The permittee shall furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The performance tests will be conducted in accordance with the provisions of 40 CFR 60.46a.

b. Compliance with emission limitations for each fuel stated in Specific Condition No. 20 above shall be demonstrated using EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), continuous emissions monitoring data, or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), or any other method as approved by the Department, in accordance with F.A.C. Rule 62-297.620. A test protocol shall be submitted for approval to the Bureau of Air Regulation at least 90 days prior to testing.

EPA Method*	For Determination of
1	Selection of sample site and velocity traverses.
2	Stack gas flow rate when converting concentrations to or from mass emission limits.
3 or 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 concentration and mass emissions.
201 or 201A	PM_{10} emissions.
6, 6C, or 19	Sulfur dioxide emissions from stationary sources.
7, or 7E	Nitrogen oxide emissions from stationary sources.
8 (modified)	Sulfuric acid mist. **
9	Visible emission determination of opacity. - At least three one hour runs to be conducted simultaneously with particulate testing. - At least one truck unloading into the mercury reactant storage silo (from start to finish).
10	Carbon monoxide emissions from stationary sources.
12	Determination of inorganic lead emissions from stationary sources.
13A or 13B	Fluoride emissions from stationary sources.
18 or 25	Volatile organic compounds concentration.
101A	Determination of particulate and gaseous mercury emissions.

EPA Method*	For Determination of
104	Determination of beryllium emissions from stationary sources.
108	Determination of particulate and gaseous arsenic emissions.
EMTIC Test Method CTM-012.WPF	Chromium and copper emissions.

* Other approved EPA test methods may be substituted for the listed method unless the Department has adopted a specific test method for the air pollutant.

** Test for sulfuric acid mist only required when coal is burned at the facility.

c. Continuous emission monitoring data required by this permit shall be collected and recorded during all periods of operation including startup, shutdown, and malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Although recorded, emissions during periods of startup, shutdown and malfunction may be excluded from the averaging calculations required to determine compliance with the emissions standards, not to exceed four (4) hours during startup, four (4) hours during shutdown, nor two (2) hours during malfunction in a 24-hour period. Excess Emissions beyond these periods shall be recorded and included in the averaging calculations required to determine compliance with the emissions standards. The permittee shall submit to the regulating agencies a Quarterly Excess Emissions Report within 30 days of the end of each calendar quarter. The report shall identify the date, time, and description of each startup, shutdown, and malfunction resulting in excess emissions. It shall also identify any steps taken to mitigate emissions during any malfunction as well as any corrective actions taken.

[Air Permit PSD-FL-196; Rule 62-210.700, F.A C.; 40 CFR 60.8; and 40 CFR 60.46a]

d. Excess emissions resulting from startup, shutdown or malfunction of a boiler shall be permitted for standards based on short-term averaging periods (shorter than 24-hour averages) as specified in this permit, providing:

a. The operators implement best operational practices to minimize emissions, and

b. Excess emissions do not exceed four (4) hours for startup, four (4) hours for shutdown, nor two (2) hours for malfunction in any 24-hour period (day).

Within one (1) working day of excess emissions due to a malfunction, the permittee shall notify the regulating agencies of the date, time, description, steps to taken to minimize emissions, and actions taken to correct the problem.

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. Excess emissions of standards based on long-term averaging periods (24-hour averages or longer) are not permitted because compliance is demonstrated by continuous monitor and provisions of this permit allow exclusion of monitoring data for periods of startup, shutdown, and malfunction.

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

This permit is issued pursuant to Chapter 403, Florida Statutes. A copy of this letter shall be filed with the referenced permit and certification and shall become part of the permit. Any party to this order has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty (30) days after this order is filed with the clerk of the Department.

Sincerely,

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6-24-99 to the person(s) listed:

Mr. James Meriwether, Okeelanta Power Limited Partnership*
Mr. James Stormer, Palm Beach County Health Department
Mr. Phil Barbaccia, SD – DEP
Mr. Gregg Worley, EPA
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.

Kori Tober (Clerk) 6-24-99 (Date)

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 31, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Gus Cepero, Authorized Representative
Okeelanta Power Limited Partnership
P.O. Box 9
South Bay, FL 33493

Re: Project No. 0990332-011-AC
Permit No. PSD-FL-196K
Okeelanta Power L.P. - Cogeneration Plant
Request to Extend Operation of Sugar Mill Boilers as Standby Units

Okeelanta Power L.P. operates a biomass cogeneration plant located near Highway 27, approximately 6 miles south of South Bay in Palm Beach County, Florida. Okeelanta Corporation operates a sugar mill and refinery at an adjacent location. For the purposes of the Department's Prevention of Significant Deterioration (PSD) and Title V operating permit programs, the two plants are considered to be a single facility. Based on the applicant's request, the initial PSD permit required permanent shutdown of the existing sugar mill boilers (except for refinery Boiler No. 16) to offset emissions from the new cogeneration boilers. This federally enforceable permit condition allowed emissions of carbon monoxide, lead, nitrogen oxides, and particulate matter to escape PSD applicability. It also allowed emissions of volatile organic compounds to escape a LAER determination. During the first 12 months of commercial operation, the permit allowed limited simultaneous operation and operation of the sugar mill boilers as standby units if all cogeneration boilers were shutdown. The Department has previously issued several modifications to these conditions related to establishing commercial operation of the cogeneration boilers as well as the ability to provide a reliable source of steam to the sugar mill.

On September 28, 1999, Okeelanta Power L.P. applied to the Department for a modification of Permit No. PSD-FL-196, which would extend the operation of the sugar mill boilers as standby units for the existing sugar mill. The Department has reviewed the modification request, the compliance history, the permitting history, and other additional information provided by Okeelanta Power L.P. The Department approves the request to operate the sugar mill boilers as standby units, but only for electrical or mechanical failure of all three cogeneration boilers. The Department denies the request for any simultaneous operation of the sugar mill boilers (except for refinery Boiler No. 16) with the cogeneration boilers. This modification also includes the addition of mechanical dust collectors that were previously approved by the Department on December 22, 1999. As summarized in the attached Final Determination, only minor changes were made to the Draft Permit. The referenced permit is hereby modified as follows:

Add the following text to the emissions unit description:

"Mechanical dust collectors are installed prior to each electrostatic precipitator to remove large particulate matter."

Revise specific condition No. 5 as follows:

"5. Each boiler shall be equipped with a(n):

- 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);
- Electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter;
- Selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of NOx; and
- Carbon injection system (or equivalent) for mercury emissions control."

Replace specific condition Nos. 17 and 18 with the following revised conditions:

"17. Standby Operation: The sugar mill boilers shall comply with the following requirements as well as Specific Condition No. 18.

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. Sugar Mill Boiler No. 16 shall be retained as a standby boiler for the cogeneration plant and shall operate only when one or more of the cogeneration boilers are shut down, or in the process of immediately shutting down. For each incident of standby use, the permittee shall record the hours of operation and which of the cogeneration boilers was shutdown.

c. 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.

18. Notification of Standby Operation:

a. Within 24 hours of any electrical or mechanical failure that prevents operation of all three cogeneration boilers, the permittee shall notify Department's South District Office and the Palm Beach County Health Department. The notification shall include a description of the problems, the planned corrective actions, and an estimate of the time the cogeneration boilers will be down.

b. Within 24 hours of restarting any sugar mill boiler (other than Boiler No. 16), the permittee shall notify the Department's South District Office and the Palm Beach County Health Department. The notification shall include an estimate of the time the sugar mill boiler will be operated and the corrective actions being taken to restore operation of the cogeneration boilers.

c. For any sugar mill boiler operated or intended to be operated more than 400 hours, the permittee shall schedule and perform all required emissions performance tests. The permittee shall provide at least 48 hours advance notice for any test to the Department's South District Office and the Palm Beach County Health Department.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

Howard L. Rhodes, Director
Division of Air Resources Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this permit modification (including the Final Determination) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 11/6/00 to the person(s) listed:

Mr. Gus Cepero, Okeelanta Power L.P.*
Mr. James Meriwether, Okeelanta Power L.P.
Mr. Ricardo Lima, Okeelanta Corporation
Mr. David Dee, Landers & Parsons
Mr. David Buff, Golder Associates
Mr. James Stormer, PBCHD
Mr. Ray Blackburn, SD
Mr. Gregg Worley, EPA
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.

Charlotte J. Hayes (Clerk) 11/6/00 (Date)

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

January 19, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Gus Cepero, Authorized Representative
Okeelanta Power Limited Partnership
P.O. Box 9
South Bay, FL 33493

Re: Project No. 0990332-013-AC
Air Permit No. PSD-FL-196L
Okeelanta Power L.P. - Cogeneration Plant
Request to Add Natural Gas as a Supplemental Fuel

Okeelanta Power L.P. operates a biomass cogeneration plant located near Highway 27, approximately 6 miles south of South Bay in Palm Beach County, Florida. Okeelanta Corporation operates a sugar mill and refinery at an adjacent location. For the purposes of the Department's Prevention of Significant Deterioration (PSD) and Title V operating permit programs, the two plants are considered to be a single facility. On June 20, 2000, Okeelanta Power L.P. applied to the Department for a modification of Permit No. PSD-FL-196 to add natural gas as a supplemental fuel to the biomass boilers to increase reliability and availability. The Department has reviewed the available information and approves the request as summarized in the attached Technical Evaluation. The Department determined that the cogeneration boilers qualified as electric utility steam generating units. Therefore, the applicant is allowed to project "representative actual annual emissions" in accordance with Rule 62-210.200(12)(d), F.A.C. and 40 CFR 52.21(b)(33). According to the applicant's projected emissions, the project will not result in a PSD significant net emissions increase after the change. Original Permit No. PSD-FL-196 is hereby modified as follows.

Add the following specific permit condition:

29. Natural Gas Firing: The permittee is authorized to modify each biomass cogeneration boiler to add natural gas as a supplemental fuel in accordance with the following specific conditions.

    a. The total heat input from the new natural gas fired burners shall not exceed 605 mmBTU per hour for each boiler. The burners shall be a low-NOx design rated for no more than 0.15 pounds of NOx per mmBTU of heat input. The preliminary design indicates that a single burner will be installed in each corner of each boiler for a total of four burners, however this is subject to change.

    b. Natural gas may be fired alone or as a supplemental fuel in combination with other authorized fuels. In accordance with Specific Condition Nos. 15 and 20 of this permit, total fossil fuel firing (including natural gas) shall not exceed 25% of the heat input on a calendar quarter basis.

    c. The biomass boilers shall comply with each limit established in Specific Condition No. 20 when firing natural gas in combination with wood, bagasse, and/or distillate oil. For the brief periods

when natural gas is fired alone, the biomass boilers shall comply with the lowest specified emission standards of any of the authorized fuels.

d. Within 180 days of completion of construction, the permittee shall submit a report summarizing at least 30 days of operational data that includes gas firing. For each day of operation, the report shall summarize data collected from the continuous monitors for each biomass boiler for opacity, CO emissions, NOx emissions, and SO_2 emissions. It shall also include the average heat inputs from each fuel, the average power generation, and the hours of operation for each day.

e. Before March 1st of each year, the permittee shall submit a report summarizing operations for the previous year in accordance with the following conditions.

(1) The report shall calculate the actual annual emissions of CO, NOx, PM/PM_{10}, SO_2, and VOC in accordance with methodology provided in the letter application for this project and generally described as follows. Emissions of CO, NOx, and SO_2 shall be based on the sum of the daily averages computed by the continuous emissions monitoring systems and the heat inputs for each fuel type. Emissions of PM/PM_{10} and VOC shall be calculated based on the required annual emissions performance tests conducted during the year and the heat inputs for each fuel type. The calculations and supporting data shall be provided for each biomass boiler. The permittee may use other methods approved in advance by the Department.

(2) The report shall summarize emissions and compare the representative actual annual emissions to the past actual annual emissions for all three biomass boilers as indicated in the following table.

Operating Hours	Heat Input mmBTU/year	Annual Emissions, Tons Per Year				
		CO	NOx	PM/PM_{10}	SO_2	VOC
Past Actual Emissions Prior to Project						
20,170	10,725,416	1526.07	753.56	172.50*	133.23	44.20
PSD Significant Emission Rates (Table 212.400-2, F.A.C.)						
----	----	100	40	25/15	40	40
Future Actual Emissions, Above Which May Trigger PSD Review						
----	----	1626.0	793.5	172.5*	173.2	84.2
Representative Actual Emissions for _____ Calendar Year						
----	----					
Do the representative actual annual emissions trigger PSD review?						
----	----	Yes / No	Yes / No	Yes / No	Yes / No	Yes / No

* *Potential emissions used due to non-compliance issues.*

As shown, the report shall indicate whether or not the project resulted in a PSD-significant net emissions increase as defined in Table 212.400-2 of Chapter 62-212, F.A.C. The permittee shall utilize the "representative actual annual emissions" methodology, defined at Rule 62-210.200(12)(d), F.A.C., and the provisions of 40 CFR 52.21(b)(33), adopted by state rule, in its demonstration. The permittee may exclude any portion of the actual emissions after the change that could have been accommodated by the unit and that is unrelated to the particular change, including increased capacity utilization due to electricity demand growth for the utility system as a whole. However, the permittee shall identify and quantify the excluded emissions and present a justification for the exclusion.

(3) If the natural gas project results in a PSD-significant emissions increase, or if the permittee fails to submit the required information, the biomass boilers shall be subject to the requirements of PSD at that future time, which shall include a BACT determination for each PSD-significant pollutant.

(4) Reports shall be submitted to the Palm Beach County Health Department and the Department's New Source Review Section and South District Office. The reports shall be submitted for five separate years that are representative of normal post-change operations after completing construction of the natural gas burner systems. The five reports shall be submitted within the 10-year period following the completion of construction for the last biomass boiler. The reports shall start with the first full calendar year following the completion of construction of the final biomass boiler.

f. The permittee shall comply with the following NSPS Subpart Da requirements.

(1) When firing natural gas, SO_2 emissions shall be less than 0.20 lb/mmBTU of heat input. Compliance with this condition shall be demonstrated by obtaining a quarterly analysis of the sulfur content from the natural gas vendor and calculating the emission rate in terms of "pounds of SO_2 / mmBTU of heat input". {Permitting Note: The SO_2 emissions when firing pipeline-quality natural gas is estimated to be approximately 0.05 lb/mmBTU based on 20 grains of sulfur per 100 SCF of natural gas. Pipeline-quality natural gas in Florida typically contains less than 1 grains per 100 SCF.}

(2) NOx emissions shall not exceed 0.15 lb/mmBTU of heat input from firing natural gas based on a 30-day rolling average . Because natural gas is being added as a supplemental fuel, compliance with this limit shall be demonstrated by the current continuous NOx emissions monitoring requirements of this permit. {Permitting Note: The current permit limit when firing biomass fuels and distillate oil is also 0.15 lb/mmBTU of heat input, as controlled by urea injection.}

[Design; Applicant Request; Permit No. PSD-FL-196; Rules 62-4.070(3), 62-210.200(12), 62-210.200(109), 62-212.300(1)(d), and 62-212.400, F.A.C.; 40 CFR 52.21(b)(33); 40 CFR 60, Subpart Da]

This permit modification is issued pursuant to Chapter 403, Florida Statutes. This modification shall supplement conditions imposed by previous permitting actions on Permit No. PSD-FL-196. Attached is original Permit No. PSD-FL-196 and a brief permitting history (Attachment A). A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

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

Executed in Tallahassee, Florida.

Howard L. Rhodes, Director
Division of Air Resources Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this permit modification was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 1/24/01 to the person(s) listed:

Mr. Gus Cepero, Okeelanta Power L.P.*
Mr. James Meriwether, Okeelanta Power L.P.
Mr. Ricardo Lima, Okeelanta Corporation
Mr. David Dee, Landers & Parsons
Mr. David Buff, Golder Associates
Mr. James Stormer, PBCHD
Mr. Ron Blackburn, SD
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

Charlotte J Hayes (Clerk) 1/24/01 (Date)

ATTACHMENT A - PERMITTING HISTORY THROUGH JANUARY 2001

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

Project No. 0990332-001-AC (PSD-FL-196A): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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: OkPLP 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. 0990332-012-AC (PSD-FL-196L): OkPLP requested to add natural gas as a supplemental fuel to the biomass boilers. Department issued Final Permit in January 2001.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DER File No. AC50-219413
PSD-FL-196
Palm Beach County

Mr. Gus Cepero, Vice President
Okeelanta Power Limited Partnership
P. O. Box 86
South Bay, Florida 33493

/

Enclosed is construction Permit Number AC50-219413 (PSD-FL-196) for a 74.9 megawatt (MW) electric cogeneration facility to be constructed at the Okeelanta Corporation sugar mill located 6 miles south of South Bay, off U.S. Highway 27 in Palm Beach County, Florida. This permit is issued pursuant to Section 403, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on Sept 29, 1993 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED,
on this date, pursuant to
§120.52(11), Florida Statutes,
with the designated Department
Clerk, receipt of which is hereby
acknowledged.

(Clerk) 9-27-93 (Date)

Copies furnished to:
David Knowles, SD
Isidore Goldman, SED
James Stormer, PBCHD
Jewell Harper, EPA
John Bunyak, NPS
David Buff, KBN

Final Determination

Okeelanta Power Limited Partnership
South Bay, Palm Beach County, Florida

74.9 Megawatt (MW) Electric Cogeneration Facility

Permit No.: AC 50-219413
PSD-FL-196

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

September 17, 1993

FINAL DETERMINATION

The Technical Evaluation and Preliminary Determination for a permit to construct (AC 50-219413/PSD-FL-196) a 71.25 megawatt (MW) electric cogeneration facility for Okeelanta Power Limited Partnership, P.O. Box 86, South Bay, Florida 33493, was distributed on June 3, 1993. The cogeneration facility will be built at Okeelanta Corporation's sugar mill located 6 miles south of South Bay, off U.S. Highway 27, Palm Beach County, Florida. The Notice of Intent to Issue was published in the Palm Beach Post on June 9, 1993. Copies of the evaluation were available for public inspection at the Department offices in Tallahassee, Ft. Myers, and West Palm Beach, and at the Palm Beach County Health Department office in West Palm Beach.

The Environmental Protection Agency and National Park Service had no negative comments on the proposed permit.

In letters dated July 2 and August 11, 1993, the applicant requested that the plant be allowed to generate 74.9 megawatts (MW) of electricity as proposed in the application, that they be allowed to burn small quantities of treated wood that may escape detection by their inspection program provided the air pollution standards are not exceeded, that the prohibition on the burning of "special waste" be deleted from the permit, that they not be required to analyze the ash, that the permit be reworded to state that the fossil fuel heat input to the boilers will be less than 25 percent on a quarterly basis instead of 25 percent on an annual basis, that the nitrogen oxide emissions be corrected from 873.1 to 862.5 tons per year (TPY), that a 3-hour sulfur dioxide emission limit for coal be added to the permit, that a visible emission standard be added to the permit, that they not be required to test the emissions from all allowed fuels during the first 180 days of operation, that they be allowed to use other test methods than the ones listed in the permit, that they be allowed more than 2 hours for excess emissions during startup conditions, and that they not be required to cover the inactive coal storage pile. Except for the request to not cover the inactive coal pile or analyze the ash, the Department finds their comments acceptable and have made the following changes, along with minor editioral changes to the proposed permit:

Specific conditions Nos. 1, 11, and 15, the project description, and the BACT and RACT determinations were revised from 71.25 to 74.9 MW, 1-hour average, except during emission compliance and equipment performance tests. This change does not increase allowable heat input or emissions of any air pollutant.

Specific condition No. 12 was revised to incorporate a plan to minimize treated/painted wood from being burned in the cogeneration facility. Limits on metals associated with treated wood needed to prevent the Acceptable Ambient Concentration from being exceeded were added to the permit.

Specific Condition No. 17 was revised to allow limited operation of both existing bagasse boilers and new cogeneration boilers during the first year while the cogeneration facility is being debugged.

Specific condition No. 18 was revised to allow additional time for excess emissions during startup. Limits on the number of startups during a time period were added to the permit.

Specific condition No. 20 was revised to include a visible emission standard and a 3-hour sulfur dioxide standard for coal based on the new source performance standard for electrical utility steam generating units.

Specific condition No. 21 was revised to allow the use of additional EPA approved compliance test methods.

Specific condition No. 23 was corrected to require a 15 day notice instead of 10 days as listed in the proposed permit prior to any scheduled compliance test.

The final action of the Department will be to issue construction permit No. AC 50-219413 (PSD-FL-196) as proposed in the Technical Evaluation and Preliminary Determination except for the changes noted above.

Florida Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Okeelanta Power Limited
Partnership
P. O. Box 86
South Bay, FL 33493

Permit Number: AC50-219413
PSD-FL-196
Expiration Date: July 1, 1996
County: Palm Beach
Latitude/Longitude: 26°35'00"N
80°45'00"W
Project: Cogeneration Facility

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-210, 212, 272, 275, 296, and 297; and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and specifically described as follows:

A 74.9 megawatt (gross) electric, (1-hour average), cogeneration facility (biomass--bagasse and wood waste material as the primary fuel, No. 2 fuel oil as a supplementary fuel, and low sulfur coal as an alternate fuel) located at Okeelanta Corporation's sugar mill that is 6 miles south of South Bay, off U.S. Highway 27, Palm Beach County, Florida. The cogeneration facility contains three Zurn spreader-stoker or equivalent steam boilers with a design heat input for each boiler of 715 MMBtu/hr on biomass and 490 MMBtu/hr on fossil fuels. Each boiler will produce approximately 455,400 lbs/hr of steam at 1,500 psig and 975°F. Particulate matter, nitrogen oxides, and mercury emissions from each boiler will be controlled by Research-Cottrell (or equivalent) electrostatic precipitator, Thermal $DeNO_x$ (or equivalent) selective non-catalytic reduction system, and an activated carbon injection system (or equivalent), respectively. Auxiliary equipment includes feed and ash handling systems, steam turbines and condensers, electric generators, cooling towers, and stacks that are 8.0 ft. in diameter and a minimum 199 ft. high.

The UTM coordinates of this facility are Zone 17, 524.9 km E and 2940.1 km N.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:
1. Application received September 30, 1992.
2. DER letter dated November 3, 1992.
3. KBN letter dated December 4, 1992.
4. Carlton letter dated December 23, 1992.
5. KBN letter dated February 17, 1993.
6. KBN letter dated May 25, 1993.
7. KBN letter dated July 2, 1993.
8. KBN letter dated August 11, 1993.

"Printed on recycled paper."

GENERAL CONDITIONS:

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 any 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 of 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 acknowledgement 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

GENERAL CONDITIONS:

reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any 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.

GENERAL CONDITIONS:

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-730.300, 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:

(x) Determination of Best Available Control Technology (BACT)
(x) Determination of Prevention of Significant Deterioration (PSD)
(x) Compliance with New Source Performance Standards (NSPS)

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 for 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:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

GENERAL CONDITIONS:

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.

SPECIFIC CONDITIONS:

Construction Details

1. Construction of the proposed cogeneration facility shall reasonably conform to the plans described in the application. The facility shall be designed, constructed, and operated so that its gross generating capacity shall not exceed 74.9 megawatt (MW), 1-hour average, except during scheduled emission compliance and equipment performance tests. Equipment performance testing in excess of 74.9 shall be limited to a total of 24 hours (cumulative) during the 180-day calendar period after initial firing of each boiler.

The permittee shall provide detailed engineering plans, 30 days after they become available, demonstrating that the steam electric generating system will not produce more than 74.9 MW at design maximum steam conditions. Such demonstration may include plans for installation of a steam pressure relief valve. If the steam electric generating system is designed with a pressure relief valve, such valve shall be installed and maintained as a requirement of this permit.

2. Boilers No. 1, 2 and 3 shall be of the spreader stoker type with a maximum heat input of 715 MMBtu/hr with biomass fuel and 490 MMBtu/hr with fossil fuels.

3. Each boiler shall have an individual stack, and each stack must have a minimum height of 199 feet. The stack sampling facilities for each stack must comply with F.A.C. Rule 17-297.345.

4. Each boiler shall be equipped with instruments to measure the fuel feed rate, steam production, steam pressure, and steam temperature.

5. Each boiler shall be equipped with a:

-Electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter;
-Selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of NO_x; and
-Carbon injection system (or equivalent) for mercury emissions control.

SPECIFIC CONDITIONS:

6. The permittee shall install and operate continuous monitoring devices for each main boiler exhaust for opacity, nitrogen oxides (NO_X), sulfur dioxide (SO_2), oxygen (O_2), and carbon monoxide (CO).

The monitoring devices shall meet the applicable requirements of Section 17-297.500, F.A.C., and 40 CFR 60.47a. The opacity monitor shall be placed in the duct work between the electrostatic precipitator and the stack or in the stack.

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 maintain air/fuel ratio parameters at an optimum. Operating procedures shall be established based on the initial emission compliance tests required by Specific Condition No. 21 below. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" shall be used as a guide. An operating plan shall be submitted to the Department within 90 days of completion of such tests.

7. For the electrostatic precipitator, the selective non-catalytic reduction process (SNCR), and the activated carbon injection mercury control system (equivalent controls allowed):

a. The permittee shall submit to the Department copies of technical data pertaining to the selected PM, NO_X, and mercury emission controls within thirty (30) days after it becomes available. These data should include, but not be limited to, guaranteed efficiency and emission rates and major design parameters.

8. 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 a 0.01 gr/acf outlet dust loading. The permittee must submit to the Department copies of technical data pertaining to the selected particulate emissions control for the mercury control system reactant storage silos within thirty (30) days after it becomes available. These data should include, but not be limited to, guaranteed efficiency, emission rates, and major design parameters.

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 it being discharged into the disposal bin.

SPECIFIC CONDITIONS:

9. Prior to operation of the source, the permittee shall submit to the Department an operation and maintenance plan that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible

10. During land clearing and site preparation, wetting operations or other soil treatment techniques appropriate for controlling unconfined particulates, including grass seeding and mulching of disturbed areas, shall be undertaken and implemented. Any open burning of land clearing debris on this site shall be performed in compliance with Department regulations.

Operational and Emission Restrictions

11. The proposed cogeneration facility steam generating units shall be constructed and operated in accordance with the capabilities and specifications described in the application. The facility shall not exceed 74.9 (gross) megawatt generating capacity, 1 hour average, except during emission compliance and equipment performance tests. Equipment performance testing shall be limited to a 180-day calendar period after initial firing of each boiler. The hourly average generation rate shall be recorded in a log and the log retained for at least 2 years. The maximum heat input rate for each steam generator shall not exceed 715 MMBtu/hr when burning 100 percent biomass and 490 MMBtu/hr when burning 100 percent No. 2 fuel oil or low sulfur coal. Maximum heat input to the entire facility (total all three boilers) shall not exceed 11.5 x 10^{12} Btu per year. Steam production of each boiler shall not exceed an average of 455,418 lbs/hr at 1,500 psig, 975°F.

12. The primary fuel for the facility shall be biomass--bagasse and wood waste material. Authorized wood waste material is clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter.

The biomass fuel used at the cogeneration facility shall not contain hazardous substances, hazardous wastes, biomedical wastes, or garbage. The fuel used at the cogeneration facility 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 waste or similar vegetative matter that has been delivered to the facility 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 waste and vegetative matter.

SPECIFIC CONDITIONS:

The permittee shall design and implement a management and testing program for the wood waste and other materials delivered to the facility 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. This program shall be submitted to the Department's Bureau of Air Regulation for review and approval at least 60 days before the commencement of operations of the cogeneration facility. At a minimum, 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. Fuel scheduled for burning shall be inspected daily. Fuel tests shall be conducted weekly for the first year of operations at the facility and monthly thereafter, if the Department determines on the basis of the prior test results that less frequent testing is appropriate. A representative sample of ash for the biomass burned during each month for the first year of operation shall be analyzed for copper, chromium and arsenic by appropriate analytical procedures per 40 CFR 261, Appendix III, described in SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods. Wood waste containing more than 70.7 ppm arsenic or 83.3 ppm chromium or 62.8 ppm copper shall not be burned based on an analysis of a composite sample.

13. Any fuel oil burned in the facility shall be "new" No. 2 fuel oil with a maximum sulfur content of 0.05 percent sulfur as determined by the appropriate test method listed in 40 CFR 60.17. "New" oil means an oil which has been refined from crude oil and has not been used in any manner that may contaminate it.

14. Any coal burned in the facility shall be low sulfur coal with a maximum sulfur content of 0.70 percent and a maximum potential emission equivalent to 1.2 lb SO_2/MMBtu.

15. The consumption of No. 2 fuel oil shall be less than 25 percent of the total heat input to each boiler unit in any calendar quarter. Not more than 71,714 tons of coal shall be burned at this facility during any 12-month period. The combined heat input for coal and oil shall be less than 25 percent of the heat input on a calendar quarter basis.

16. The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, beryllium content (coal only), sulfur content, and equivalent SO_2 emission rate (in lbs/MMBtu) of each fuel oil and coal delivery shall be kept in a log for at least two years. For each calendar month, the calculated SO_2 emissions and 12-month rolling average shall be determined (in tons) and kept in a log.

SPECIFIC CONDITIONS:

17. During the first three years of commercial cogeneration facility operation, the existing Boilers Nos. 4, 5, 6, 10, 11, 12, 14, and 15 (Permit Nos. AO50-169210, 190690, 175414, 190693, 175411, 169215, 189904, and 209094, respectively) may be retained for standby operation. During the period from initial firing to commercial operation, all three cogeneration boilers can be operated simultaneously with the existing boilers. Only biomass and No. 2 fuel oil may be used in the cogeneration boilers during this period. If more than 910,836 lb/hr steam is generated in the cogeneration boilers, steam in excess of 910,836 lb/hr must be sent to the Okeelanta sugar mill, and the existing boiler's steam production reduced by an equivalent amount. This period shall not exceed a total duration of 12 months. During this 12-month period, simultaneous operation of the existing boilers and the cogeneration boilers shall not occur on more than a total of 90 calendar days. After the first year of cogeneration facility operation, the existing boilers may be operated only when all three cogeneration boilers are shutdown. During operation, the existing boilers must meet all requirements in the most recent construction and operation permits for the boilers. These existing boilers shall be shutdown and rendered incapable of operation within three (3) years of commercial startup of the cogeneration facility, but no later than January 1, 1999.

18. Boiler No. 16 (AC50-191876) may be retained as a standby boiler for the cogeneration facility provided its permit is amended to authorize standby use. Boiler No. 16 may be operated during initial startup, debugging, and testing of the cogeneration facility for a period not to exceed 12 months following initial firing of fuel in the new boilers. After the first year of cogeneration operation, this boiler may be operated only when one or more of the three cogeneration boilers are shutdown. During operation, this boiler must meet all requirements in the current construction or operating permit for the boiler.

19. For the biomass, coal, fly ash, and mercury control system reactant handling facilities:

a. All conveyors and conveyor transfer points shall be enclosed to preclude PM emissions (except those directly associated with the stacker/reclaimers, for which enclosure is operationally infeasible).

b. Inactive coal storage piles shall be shaped, compacted, and oriented to minimize wind erosion. Sod, wetting agents, synthetic or other appropriate materials shall be used to cover those portions of the inactive coal pile that are prone to wind or water erosion.

SPECIFIC CONDITIONS:

c. Water sprays or chemical wetting agents and stabilizers shall be applied to storage piles, handling equipment, unenclosed transfer points, etc. during dry periods and as necessary to all facilities to maintain an opacity of less than or equal to 5 percent, except when adding, moving or removing coal from the coal pile, which would be allowed no more than 20 percent opacity.

d. 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. Particulate matter emissions from each of the three silos shall not exceed a visible emission reading of 5 percent opacity. A visible emission test is to be performed annually on each silo.

20. Visible emissions from any boiler shall not exceed 20 percent opacity, 6-minute average, except up to 27 percent opacity is allowed for up to 6 minutes in any 1-hour period. Based on a maximum heat input to each boiler of 715 MMBtu/hr for biomass fuels and 490 MMBtu/hr for No. 2 fuel oil and coal, stack emissions shall not exceed any limit shown in the following table:

	Emission Limit (per boiler)[d]						Total: All[e] Three Boilers
	Biomass		No. 2 Oil		Bit. Coal		
Pollutant	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(TPY)
Particulate (TSP)	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Particulate (PM_{10})	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Sulfur Dioxide							
3-hour average	---	---	---	---	1.2	588.0	---
24-hour average	0.10	71.5	0.05	24.5	1.2	588.0	---
Annual average	0.02[e]	---	---	---	1.2[e]	---	1,134.3[f]
Nitrogen Oxides							
Annual average	1.15[e]	707.36[e]	1.15[e]	773.69[e]	0.17[e]	83.3[e]	861.8
Carbon Monoxide							
3-hour average	0.35	250.3	0.1	98.0	0.2	98.0	1,012.8
Volatile Organic Compounds	0.04	42.9	0.03	14.7	0.03	14.7	345.0
Lead	2.8×10^{-5}	0.0218	5.4×10^{-7}	0.0004	5.4×10^{-5}	0.031	0.17
Mercury	2.8×10^{-06} 0.28×10^{-05}	0.00215[g] 0.0022[h]	5.4×10^{-6}	0.00216	5.4×10^{-5}	0.0264	0.0301

SPECIFIC CONDITIONS:

Beryllium	---	---	3.5×10^{-7}	0.00017	5.9×10^{-6}	0.0029	0.0052
Fluorides	---	---	6.3×10^{-6}	0.003	0.024	11.8	21.2
Sulfuric Acid Mist	0.003	2.15	0.0015	0.74	0.036	17.6	34.6

[a]Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.
[b]Emission limit for bagasse. Subject to revision after testing pursuant to Specific Conditions Nos. 24 and 25.
[c]Emission limit for wood waste. Subject to revision after testing pursuant to Specific Conditions Nos. 24 and 25.
[d]The emission limit shall be prorated when more than one type of fuel is burned in a boiler.
[e]Limit heat input from No. 2 fuel to less than 25% of total heat input on a calendar quarter basis, coal to 73,714 tons during any 12-month period, and the combination of oil and coal to less than 25% of the total heat input on a calendar quarter basis.
[f]Compliance based on a 12-month rolling average.

The permittee shall comply with the excess emissions rule contained in F.A.C. Rule 17-210.700. In addition, the permittee is allowed excess emissions during startup conditions, provided such excess emissions do not exceed a duration of four hours, and such emissions in excess of two hours do not exceed six (6) times per year.

Compliance Requirements

21. Stack Testing

a. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial startup, the permittee shall conduct emission compliance tests for all air pollutants listed in Specific Condition No. 20 (including visible emissions). Tests shall be conducted during normal operations (i.e., within 10 percent of the permitted heat input). The permittee shall furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The emission compliance tests will be conducted in accordance with the provisions of 40 CFR 60.46a.

b. Compliance with emission limitations for each fuel stated in Specific Condition No. 20 above 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

SPECIFIC CONDITIONS:

Department, in accordance with F.A.C. Rule 17-297.620. A test protocol shall be submitted for approval to the Bureau of Air Regulation at least 90 days prior to testing.

EPA Method*	For Determination of
1	Selection of sample site and velocity traverses.
2	Stack gas flow rate when converting concentrations to or from mass emission limits.
3 or 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 concentration and mass emissions.
201 or 201A	PM_{10} emissions.
6, 6C, or 19	Sulfur dioxide emissions from stationary sources.
7 or 7E	Nitrogen oxide emissions from stationary sources.
8	Sulfuric acid mist.
9	Visible emission determination of opacity. - At least three one hour runs to be conducted simultaneously with particulate testing. - At least one truck unloading into the mercury reactant storage silo (from start to finish).
10	Carbon monoxide emissions from stationary sources.
12	Determination of inorganic lead emissions from stationary sources.
13A or 13B	Fluoride emissions from stationary sources.
18 or 25	Volatile organic compounds concentration.
101A	Determination of particulate and gaseous mercury emissions.
104	Determination of beryllium emissions from stationary sources.
108	Determination of particulate and gaseous arsenic emissions.

SPECIFIC CONDITIONS:

EMTIC Test Method CTM-012.WPF	Chromium and copper emissions.

*Other approved EPA test methods may be substituted for the listed method unless the Department has adopted a specific test method for the air pollutant.

22. Emission compliance tests shall be conducted under such conditions as the Department shall specify based on representative performance of the facility. The permittee shall make available to the Department such records as may be necessary to determine the conditions of the emission compliance tests.

23. The permittee shall provide 30 days notice of the equipment performance tests or 15 working days for stack tests in order to afford the Department the opportunity to have an observer present.

24. Stack tests for particulates, NO_x, SO_2, sulfuric acid mist, CO, VOC, lead, mercury, beryllium, fluorides, arsenic, chromium, copper, and visible emissions shall be performed once every six months during the first two years of facility operation in accordance with Specific Conditions Nos. 21, 22, and 23 above. If the test results for the first two years of operation indicate the facility is operating in compliance with the terms of approval and of applicable permits and regulations, the tests will thereafter occur according to the following schedule:

-Annually for particulates, sulfur dioxide,* sulfuric acid mist,* NO_x, CO, VOC, mercury, arsenic, chromium, copper and visible emissions.
-Once every five years (at permit renewal time) for SO_2, sulfuric acid mist, lead, beryllium, and fluorides.

*Test required only during years coal is burned in the boilers.

25. After conducting the initial stack tests required under Specific Condition No. 24 above, a fuel management plan shall be submitted to the Department and Palm Beach County within 90 days specifying the fuel types and fuel quantities to be burned in the facility in order to not exceed the facility annual mercury, lead, beryllium, and fluorides emission limits specified in Condition 10

SPECIFIC CONDITIONS:

above. The plan shall include mercury emission factors based on stack testing, and may include revised mercury emission factors and baseline emission estimates for the existing Okeelanta facility.

Reporting Requirements

26. Stack monitoring, fuel usage, and fuel analysis data shall be reported to the Department's South and Southeast District Offices and to the Palm Beach County Health Unit on a quarterly basis commencing with the start of commercial operation in accordance with 40 CFR, Part 60, Sections 60.7 and 60.49a, and in accordance with Section 17-297.500, F.A.C.

27. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

28. An application for an operation permit must be submitted to the South District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Issued this 27 day
of September, 1993

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell

Virginia B. Wetherell, Secretary
Department of Environmental
Protection

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

Enclosed is final air permit No. PSD-FL-196M for the cogeneration plant located off U.S. Highway 27 and approximately six miles south of South Bay in Palm Beach County, Florida. 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. As noted in the Final Determination (attached), only minor changes were made to correct typographical errors. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

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 Notice of Final Permit (including the Final Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 2/1/02 to the persons listed below.

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, SD
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 (Clerk) February 1, 2002 (Date)

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

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

Howard L. Rhodes, Director
Division of Air Resources Management

1/31/02
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 (NOx), 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 (400 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. Four burners are installed with one in each corner the boiler. The maximum heat input rate from all four burners is 400 MMBtu per hour.
   - Mechanical dust collectors consisting of four, large diameter, multi-tube modules with airfoil vanes or equivalent equipment. The mechanical dust collectors shall be installed and maintained as pre-control devices prior to each electrostatic precipitator and designed for a removal efficiency of at least 85% of the particulate matter greater than 10 microns in size (assuming a specific gravity of 2.00).
   - An electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter.

- A selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of 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, 400 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^{+6} MMBtu 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 Methods 3050/6010 (EPA Method SW-846) 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 the operating temperature recommended by the ESP manufacturer is maintained (approximately 340° F to 350 ° F), it shall be placed on line and the boiler shall comply with the opacity standard specified in Condition No. 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 than twenty 6-minute block averages of opacity monitoring data shall be excluded in a 24-hour period due to documented malfunctions.

2) Hourly CO and NOx emission rate values collected during startup, shutdown, or documented malfunction may be excluded from the 30-day and/or 12-month compliance averages. No more than six hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a cold startup. No more than three hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a warm startup. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a malfunction. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a shutdown. For each cogeneration boiler, no more than 183 hourly emission rate values shall be excluded during any calendar quarter.

3) All valid hourly SO_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 identify the number of startups, the number of shutdowns, and the number of malfunctions that occurred during the year for each boiler. For each boiler's CO and NOx monitors, the report shall identify the annual hours of emission data excluded from the compliance determination due to each type of incident (startups; shutdowns; and documented malfunctions).

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

COMPLIANCE METHODS AND REPORTING

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 within 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).

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 O2
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.]

CONTENTS

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Appendix B. General Conditions
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Appendix D. Final BACT Determinations
Appendix E. Continuous Monitor Requirements

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 rolling 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 SO2 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:

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

1-30-02
(Date)

Recommended By:

C. H. Fancy, Chief
Bureau of Air Regulation

1/30
(Date)

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

1/31/02
(Date)

{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 the weigh scales. The permittee shall continuously monitor the fuel input rate based on the fuel flow monitors calculating the maximum heat input rate (24 hour average) for each fuel during each day of operation.

   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

Spreader stoker boiler with maximum heat input of 715 MMBtu/hour

ARMS EU ID No. _____ Cogeneration Boiler: ___ A ___ B ___ C

Unit Operation in Calendar Quarter

_____ 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

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)

Auxiliary Fuels

Pipeline-quality natural gas

Distillate oil (≤ 0.05% sulfur by wt.)

Pollutant Monitored *(Check one.)*

___ **CO** ___ **NOx** ___ **SO_2** ___ **Opacity**

Calendar Quarter of Operation Covered *(Check one.)*

Year: _____ ___ **1** ___ **2** ___ **3** ___ **4**

Continuous Monitor MS Information

Manufacturer: _____

Model No. _____

Date of last certification or audit: _____

Emission Standards

_____ lb/MMBtu of heat input, 30-day rolling avg.

_____ lb/MMBtu of heat input, 12-month rolling avg.

Emission Data Summary

1. Duration of excess emissions in reporting period due to:
   - a. Startup/shutdown ..... _____
   - b. Control equipment problems ..... _____
   - c. Process problems ..... _____
   - d. Other known causes ..... _____
   - e. Unknown causes ..... _____
2. Total duration of excess emissions ..... _____
3. [Total duration of excess emissions] 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.

CMS Performance Summary

1. CMS downtime in reporting period due to:
   - a. Monitor Equipment Malfunctions ..... _____
   - b. Non-Monitor Equipment Malfunctions ..... _____
   - c. Quality Assurance Calibration ..... _____
   - d. Other Known Causes ..... _____
   - e. Unknown Causes ..... _____
2. Total CMS Downtime ..... _____
3. [Total CMS Downtime] x (100%) ..... _____
   [Total source operating time]

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.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 2, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ricardo Lima, Vice President and General Manager
Okeelanta Power L.P.
8001 U.S. Highway 27 South
South Bay, Florida 33493

RE: Okeelanta Cogeneration Facility
Project No. 0990332-015-AC
Air Permit No. PSD-FL-196N
Permit Modification: 74.9 MW (Gross) Output to 74.9 MW (Net) Output

Dear Mr. Lima:

On March 26, 2001, the Department received your request to change the basis of the restriction on electrical generating capacity of the cogeneration plant from "gross" to "net" output. Based on the information provided and conversations with the Department's Bureau of Air Regulation and Siting Coordination Office, this request is approved. The permit is hereby modified as shown below.

Page 1, Placard Page: The first sentence of the second paragraph is revised to:

> "A 74.9 megawatt (~~gross~~ net) electric (1-hour average), cogeneration facility (biomass – bagasse and wood waste material as the primary fuel, No. 2 fuel oil as a supplementary fuel, and low sulfur coal as an alternate fuel) located at Okeelanta Corporation's sugar mill that is 6 miles south of South Bay, off U.S. Highway 27, Palm Beach County, Florida."

Page 5, Construction Details, Specific Condition No. 1: The second sentence of this condition is revised to:

> "The facility shall be designed, constructed, and operated so that its ~~gross~~ net generating capacity shall not exceed 74.9 megawatt (MW), 1-hour average~~, except that during scheduled emission compliance and equipment performance tests~~."

Page 7, Operational and Emission Restrictions, Specific Condition No. 11: The second sentence of this condition is revised to:

> "The facility shall not exceed 74.9 (~~gross~~ net) megawatt generating capacity, 1-hour average~~, except during emission compliance and equipment performance tests~~."

This permit modification is issued pursuant to Chapter 403 of the Florida Statutes. Attached is original Permit No. PSD-FL-196 and a brief permitting history (Attachment A). A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of

Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty (30) days after this order is filed with the clerk of the Department.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5/4/01 to the person(s) listed:

Mr. Ricardo Lima, OkPLP*
Mr. James Meriwether, OkPLP
Mr. David Buff, Golder Associates
Mr. David Dee, Landers and Parsons
Mr. James Stormer, PBCHD
Mr. Buck Oven, Siting Coordination Office
Mr. Ron Blackburn, SD Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

Charlotte J. Hayes 5/4/01
(Clerk) (Date)

ATTACHMENT A - PERMITTING HISTORY THROUGH APRIL 2001

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

Project No. 0990332-001-AC (PSD-FL-196A): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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): OkPLP 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: OkPLP 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. 0990332-012-AC (PSD-FL-196L): OkPLP requested to add natural gas as a supplemental fuel to the biomass boilers. Department issued Final Permit in January 2001.

Project No. 0990332-012-AC (PSD-FL-196M): OkPLP requested modification of the CO and SO_2 emissions standards. This project is pending.

Project No. 0990332-012-AC (PSD-FL-196N): OkPLP requested modification to change restriction from 74.9 "Gross" MW Output to 74.9 "Net" MW Output. This is the current project.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

Authorized Representative:
Mr. Rodney Williams, Plant Manager

Project No. 0990332-016-AC
Air Permit No. PSD-FL-196(O)
Okeelanta Cogeneration Plant
Increased Heat Input Rates
Palm Beach County, Florida

Enclosed is Final Air Permit No. PSD-FL-196(O), which authorizes increases to the hourly and annual heat input rates for the three existing boilers at the Okeelanta Cogeneration Plant, which is located off U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida. As noted in the attached Final Determination, only minor changes and clarifications were made.

This permit is issued pursuant to Chapter 403, Florida Statutes. Any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty (30) days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10/29/03 to the persons listed:

Mr. Rodney Williams, New Hope Power*
Mr. James Meriwether, New Hope Power
Mr. David Buff, Golder Associates Inc.
Mr. David Dee, Landers & Parsons
Mr. James Stormer, PBCHD
Mr. Ron Blackburn, SD Office
Mr. Gregg Worley, EPA Region 4 Office
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 / October 29, 2003
(Clerk) (Date)

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

PERMITTEE

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

Authorized Representative:
Mr. Rodney Williams, Plant Manager

Air Permit No. PSD-FL-196(O)
Project No. 0990332-016-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 and refinery. 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 revised specific conditions of the permit. This permit modification authorizes an increase in the hourly heat input rate from 715 to 760 MMBtu per hour per boiler and removes the previous limit on the annual heat input rate ($11.5 \times 10^{+06}$ MMBtu per year) for the three boilers combined. As a result of the changes, BACT determinations were required for emissions of carbon monoxide, fluorides, lead, nitrogen oxides, particulate matter, sulfur dioxide, sulfuric acid mist, and volatile organic compounds. In addition, Condition No. 15 was revised to simply require permanent shutdown of the existing Okeelanta sugar mill boilers, which were part of the netting analysis for the original project.

The cogeneration plant is located off U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida. The UTM coordinates are Zone 17, 524.90 km East, and 2940.10 km North. The map coordinates are latitude 26° 35' 00" N and longitude 80° 45' 00" W.

STATEMENT OF BASIS

This PSD air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Part 52, Section 21 of the Code of Federal Regulations. Specifically, this permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, Rule 62-212.400, F.A.C. The permittee is authorized to perform the proposed work and operate the installed equipment in accordance with the conditions of this permit, the conditions of the Title V operation permit, and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

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

Michael G. Cooke, Director
Division of Air Resources Management

10/27/03
Effective Date

"More Protection, Less Process"

Printed on recycled paper.

FACILITY DESCRIPTION

The facility consists of two adjacent plants. Okeelanta Corporation (ARMS ID No. 0990005) operates a sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) including packaging and transshipment activities. New Hope Power Partnership (ARMS ID No. 0990332) operates a 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). The cogeneration plant, sugar mill, and sugar refinery are all considered a single facility for purposes of the PSD and Title V regulatory programs. This permit addresses the cogeneration plant, which consists of the following emissions units.

ID	Emission Unit Description
001	Cogeneration Boiler A (760 MMBtu per hour)
002	Cogeneration Boiler B (760 MMBtu per hour)
003	Cogeneration Boiler C (760 MMBtu per hour)
004	Material handling and storage

REGULATORY CLASSIFICATION

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

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

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

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

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

PERMITTING AUTHORITY

All documents related to PSD applications for permits to construct or modify 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. All documents related to applications for permits to operate the cogeneration plant shall be submitted to the Air Resource Section of the Department's South District Office at P.O. Box 2549, Fort Myers, Florida 33902-2549. Copies of all such documents 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.

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.

RELEVANT DOCUMENTS

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

- Air Permit No. PSD-FL-196 issued September 27, 1993 and all subsequent modifications.
- Permit application received on September 6, 2002 and all related correspondence to make complete.

APPENDICES

The following Appendices are attached as part of this permit.

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

CITATION FORMAT

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

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. General Conditions: The permittee is subject to, and shall operate under, the attached General Conditions listed in Appendix B of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of each subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, and 60 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Permit Expiration: The original expiration date for the construction of this plant was July 1, 1996. Construction of the cogeneration plant is complete and commercial operation has commenced. This revised permit does not authorize any additional construction. The expiration date of this revised permit is September 1, 2004 strictly for the purpose of processing a Title V air permit revision to incorporate these changes. All physical construction is complete. [Rule 62-4.210(2), F.A.C.]

4. Effective Date: The effective date of the modified PSD permit is specified on the placard page (page 1).

5. Relaxations of Restrictions on Pollutant Emitting Capacity: If a previously permitted facility or modification becomes a facility or modification which would be subject to the preconstruction review requirements of this rule if it were a proposed new facility or modification solely by virtue of a relaxation in any federally enforceable limitation on the capacity of the facility or modification to emit a pollutant (such as a restriction on hours of operation), which limitation was established after August 7, 1980, then at the time of such relaxation the preconstruction review requirements of this rule shall apply to the facility or modification as though construction had not yet commenced on it. [Rule 62-212.400(2)(g), F.A.C.]

6. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

7. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

8. Title V Permit Revision: Pursuant to Rule 62-213.420(1)(a)2, F.A.C., the permittee shall submit an application for a revised Title V air operation permit at least ninety (90) days before the expiration of this permit, but no later than 180 days after commencing operation. In accordance with Rule 62-213.412(2), F.A.C., the permittee may immediately implement the changes authorized by this air construction permit after submitting the application for a revised Title V air operation permit to the Permitting Authority and providing copies of the application to EPA Region 4 and each Compliance Authority. To apply for a revised Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. As necessary, the application shall include a Compliance Assurance Monitoring Plan. The application shall be submitted to the Department's South District Office with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, 62-213.412, and 62-213.420, F.A.C.]

This section of the permit addresses the following emissions units.

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

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

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

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

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

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

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 natural gas and distillate oil as auxiliary fuels. Natural gas and distillate oil are fired at startup and shutdown, when necessary to ensure good combustion, to supplement biomass fuel, and for periods when the biomass fuel supply is interrupted. No other fuels are authorized. *{Permitting Note: Each boiler was originally designed to fire low sulfur coal as an emergency backup fuel, but no transfer, crushing, or storage systems were ever installed. The permittee shall obtain a permit modification before firing any other fuel (including coal) not specifically authorized by this permit.}*

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. Four burners are installed with one in each corner of the boiler. The maximum heat input rate from all four burners is 605 MMBtu per hour.
   - Mechanical dust collectors consisting of four, large diameter, multi-tube modules with airfoil vanes or equivalent equipment. The mechanical dust collectors shall be installed and maintained as pre-control devices prior to each electrostatic precipitator and designed for a removal efficiency of at least 85% of the particulate matter greater than 10 microns in size (assuming a specific gravity of 2.00).
   - An electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter.

- A selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of 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 monitoring systems (CEMS) and continuous opacity monitoring systems (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 760 MMBtu/hr when burning 100 percent biomass, 605 MMBtu/hr when burning 100 percent natural gas, and 490 MMBtu/hr when burning 100 percent very low sulfur distillate oil. The steam production of each boiler shall not exceed an average of 506,100 pounds per hour at 1,500 psig and 975°F. The operating hours of the cogeneration boilers are not restricted (8760 hours per year).

11. Primary Fuel: The primary fuel for the plant shall be biomass, which shall consist of bagasse and authorized wood material. Bagasse is the fibrous vegetative residue remaining after the sugarcane milling process. Authorized wood material is clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter. Each cogeneration boiler shall combust no more than 30% by weight yard waste (yard trash) on a calendar quarter basis that is defined as a municipal solid waste (MSW) in 40 CFR 60.51a. The biomass fuel used at the cogeneration plant shall not contain hazardous substances, hazardous wastes, biomedical wastes, or garbage. The fuel used at the cogeneration plant shall not contain special wastes, except wood, lumber, trees, tree remains, bagasse, cane tops and leaves, and other clean vegetative and cellulose matter. The permittee shall perform a daily visual inspection of any wood material or similar vegetative matter that has been delivered to the plant for use as fuel. Any shipment observed to contain prohibited materials shall not be used as fuel, unless such materials can be readily segregated and removed from the wood material and vegetative matter.

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

    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 Methods 3050/6010 (EPA Method SW-846) 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 distillate oil and pipeline natural gas as auxiliary fuels. Distillate oil shall be new No. 2 oil with a maximum sulfur content of 0.05 percent sulfur by weight as determined by the appropriate test method listed in 40 CFR 60.17. "New" oil is oil that has been refined from crude oil and that has not been used in any manner that may contaminate it. Each boiler may startup solely on pipeline natural gas or distillate oil.

13. Fossil Fuel Limitation: The firing of fossil fuels (distillate oil and natural gas) shall be less than 25 percent of the total heat input to each cogeneration boiler during any calendar quarter.

14. Fuel Records: The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, and sulfur content of each fuel oil delivery shall be kept in a log for at least five years. For each calendar month, the actual monthly SO_2 emissions and the 12-month rolling total SO_2 emissions shall be determined and kept in a log.

15. Permanent Shutdown: Sugar mill boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15 shall remain permanently shutdown and rendered incapable of operation. *{Permitting Note: Okeelanta Corporation's Boiler No. 16 may operate in accordance with modified Permit No. PSD-FL-169(A).}* [Rule 62-212.400, F.A.C.]

EMISSIONS LIMITING STANDARDS

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

Pollutant	Averaging Period	Emissions Standards per Boiler [f]	
		lb/MMBtu	lb/hr
Carbon Monoxide (CO) [a]	30-day rolling CEMS avg.	0.50	380.0
	12-month rolling CEMS avg.	0.35	
Nitrogen Oxides (NOx) [b]	30-day rolling CEMS avg.	0.15	114.0
Sulfur Dioxide (SO_2) [c]	24-hour rolling CEMS avg.	0.20	152.0
	30-day rolling CEMS avg.	0.10	
	12-month rolling CEMS avg.	0.06	
Stack Opacity [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.	0.026	19.8
Volatile Organic Compounds (VOC) [f]	3-run test avg.	0.05	38.0
Mercury [g]	3-run test avg.	5.4×10^{-06}	NA
Lead and Fluorides [h]	The BACT determination for lead and fluoride emissions is the use of fuels containing low levels of these compounds (bagasse, wood, distillate oil, and natural gas) and prospective removal with the fly ash by the mechanical dust collectors and electrostatic precipitators.		

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. In addition, the CO CEMS shall record CO emissions in terms of "ppmvd corrected to 3% oxygen" for each 1-hour block average and each 24-hour block average (daily average). *{Permitting Note: CO emissions data recorded and reported in terms of "ppmvd corrected to 3% oxygen" are for informational purposes only.}*

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 mercury standards shall be determined by the average of three test runs conducted in accordance with EPA Method 101A or 29. Emissions in excess of this standard shall be a violation of the permit. In addition, if two or more cogeneration boilers exceed the annual mercury emission limit, the permittee shall reactivate the carbon injection system for all three units within 30 days of the stack test report due date. The minimum carbon injection rate shall be at least 7 pounds per hour. Within 60 days of the stack test report due date, the permittee shall submit to the permitting and compliance authorities a mercury testing protocol designed to establish an effective carbon injection rate to control mercury emissions. Within 60 days of receiving approval for the mercury testing protocol by the permitting authority, the permittee shall begin the approved testing program. At a minimum, the permittee shall submit a full engineering report summarizing the uncontrolled emissions, controlled emissions, fuels, operating capacities, and recommending a minimum activated carbon injection rate to control mercury emissions.

h. The particulate matter standard is also a surrogate standard for lead emissions. *{Permitting Note: For reporting purposes, average lead emissions are expected to be 2.6×10^{-05} lb/MMBtu and average fluoride emissions are expected to be 1.9×10^{-04} lb/MMBtu when firing bagasse/wood.}*

i. Each boiler shall comply with the standards when firing any combination of authorized fuels. The "lb/hour" rates are based on the highest emission standard shown for that pollutant. Required compliance tests shall be performed in accordance with the requirements of Condition No. 19. The cogeneration boilers are also subject to the new source performance standards (NSPS Subpart Da) for new electric utility steam generating units. These requirements include the general provisions of Subpart A in 40 CFR 60, as well as the following source-specific applicable requirements: 60.40a

(Applicability and Designation of Affected Facility); 60.41a (Definitions); 60.42a (Standards for Particulate Matter); 60.43a (Standard for Sulfur Dioxide); 60.44a (Standard for Nitrogen Oxides); 60.46a (Compliance Provisions); 60.47a (Emissions Monitoring); 60.48a (Compliance Determination Procedures and Methods); and 60.49a (Reporting Requirements). The cogeneration boilers are also subject to Rule 62-296.405(2), F.A.C. (Fossil Fuel Steam Generators with more than 250 MMBtu per Hour of Heat Input), Rule 62-296.410, F.A.C. (Carbonaceous Fuel Burning Equipment), and Rule 62-296.570, F.A.C. (Reasonably Available Control Technology Requirements for Major VOC and NOx Facilities).

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

17. Material Handling: The following conditions apply to the biomass, ash, and activated carbon handling facilities.

    a. All conveyors and conveyor transfer points shall be enclosed to preclude PM emissions (except those directly associated with the stacker/reclaimer, for which enclosure is operationally infeasible).

    b. Water sprays, chemical wetting agents, and/or stabilizers shall be applied to storage piles, handling equipment, unenclosed transfer points, etc. during dry periods and as necessary to prevent visible emissions. When adding, moving or removing material from the storage pile, visible emissions of no more than 20% opacity are allowed.

    c. The mercury control system reactant storage silos shall be maintained at a negative pressure while operating with the exhaust vented to a filter control system. Visible emissions from any storage silo shall not exceed 5 percent opacity based on a 6-minute block average. A visible emissions test (EPA Method 9) shall be performed at least annually for each silo that is loaded with carbon during the federal fiscal year.

STARTUP, SHUTDOWN, AND MALFUNCTION

18. Startup, Shutdown, and Malfunction Requirements: The permittee shall comply with the following requirements regarding periods of startup, shutdown, and malfunction for each cogeneration boiler.

    a. *Definitions*

        1) Excess emissions are emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions that occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

        2) Startup is the commencement of operation of a boiler which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which may result in excess emissions. Periods of startup for each boiler shall end once steam generation reaches 150,000 pounds per hour. A cold startup is a startup after the boiler has been shutdown for 24 hours or more. A warm startup is a startup after the boiler has been shutdown for less than 24 hours.

        3) Shutdown is the cessation of the operation of a boiler for any purpose after steam generation drops below 150,000 pounds per hour.

        4) Malfunction is any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

    b. *Prohibition*: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. Emissions data recorded during such preventable periods shall be included in the compliance averages. [Rule 62-210.700(4), F.A.C.]

c. *Monitoring Data Exclusion*: Each continuous monitoring system shall operate and record data during all periods of operation (including startup, shutdown, and malfunction) except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Provided the operators implement best operational practices to minimize the amount and duration of emissions, the following conditions apply. Pursuant to Rules 62-210.700(1) and (5), F.A.C., these conditions consider the variations in operation of the cogeneration boilers.

1) Natural gas or distillate oil shall be fired during startup prior to energizing the electrostatic precipitator (ESP). Once the operating temperature recommended by the ESP manufacturer is maintained (approximately 340° F to 350 ° F), it shall be placed on line and the boiler shall comply with the opacity standard specified in Condition No. 16. The ESP shall be on line and functioning properly before firing any biomass. The opacity limit does not apply when the ESP is off line due to warm startup, cold startup, or shutdown. No more than twenty 6-minute block averages of opacity monitoring data shall be excluded in a 24-hour period due to documented malfunctions.

2) Hourly CO and NOx emission rate values collected during startup, shutdown, or documented malfunction may be excluded from the 30-day and/or 12-month compliance averages. No more than six hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a cold startup. No more than three hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a warm startup. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a malfunction. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a shutdown. For each cogeneration boiler, no more than 183 hourly emission rate values shall be excluded during any calendar quarter.

3) All valid hourly SO_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 identify the number of startups, the number of shutdowns, and the number of malfunctions that occurred during the year for each boiler. For each boiler's CO and NOx monitors, the report shall identify the annual hours of emission data excluded from the compliance determination due to each type of incident (startups; shutdowns; and documented malfunctions).

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

COMPLIANCE METHODS AND REPORTING

19. Stack Test Requirements

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

b. *Annual Tests*: At least once during each federal fiscal year, the permittee shall conduct compliance tests for emissions of mercury, particulate matter, and volatile organic compounds.

c. *Renewal Tests*: Within the 12-month period prior to submitting an application to renew the Title V air operation permit, the permittee shall conduct compliance tests for emissions of, mercury, particulate matter, and volatile organic compounds. Tests shall be conducted at five-year intervals.

d. *Test Procedures*: The emission compliance tests shall be conducted in accordance with the provisions of Chapter 62-297, F.A.C., 40 CFR 60.46a (NSPS Subpart Da), and as summarized in Appendix C of this permit. The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. The biomass fuel feed for each test run shall consist of at least 45% wood materials by weight. Testing of emissions shall be conducted with each cogeneration boiler operating at permitted capacity, which is defined as a heat input rate between 684 and 760 MMBtu/hour and firing 100% biomass. If it is impracticable to test at permitted capacity, a cogeneration boiler may be tested at less than the maximum permitted capacity; in this case, subsequent operation is limited to 110 percent of the test rate until a new test is conducted. Within three days of completing a test below permitted capacity, the permittee shall provide written notification of the restricted operational capacity to the Compliance Authority. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(7)(a)9, F.A.C. and 40 CFR 60.7, 60.8]

e. *Test Methods*: Compliance with the emission limits specified in this permit shall be demonstrated using EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

EPA Method	Description
1	Selection of sample site and velocity traverses
2	Stack gas flow rate when converting concentrations to or from mass emission limits
3A	Gas analysis when needed for calculation of molecular weight or percent O2
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. 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]

20. 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.

21. Quarterly Reports: For each cogeneration boiler, the permittee shall submit a quarterly report for each required continuous emissions and opacity monitoring system in accordance with the requirements specified in Appendix E of this permit. The permittee shall also submit a quarterly summary of the fuel analyses, fuel usage, and equipment malfunctions. For each malfunction, the report shall identify the cause (if known), and corrective actions taken. The quarterly reports and summaries shall be submitted to the Compliance Authority no later than 30 days following each calendar quarter.

22. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. Along with this report, the permittee shall also submit a summary of CO emissions from each cogeneration boiler in terms of "ppmvd corrected to 3% oxygen based on a 24-hour average (day)" for each operational day. [Rule 62-210.370(2), F.A.C.]

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SECTION IV. APPENDIX A
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

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: Unless otherwise specified by permit, 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 that are greater than the PSD significant emission rates identified in Table 62-212.400-2, F.A.C. for the following pollutants: carbon monoxide, nitrogen oxides, particulate matter, sulfur dioxide, volatile organic compounds, lead, fluorides, and sulfuric acid mist. Therefore, the project is subject to PSD preconstruction review and the Department makes the following determinations of Best Available Control Technology (BACT) for these pollutants.

Final BACT Determinations

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

Pollutant	BACT Standards for Each Cogeneration Boiler		
	Averaging Period	lb/MMBtu	lb/hr
Carbon Monoxide (CO) *Based on "good combustion practices".*	30-day rolling CEMS avg.	0.50	380.0
	12-month rolling CEMS avg.	0.35	
Nitrogen Oxides (NOx) *Based on the application of SNCR.*	30-day rolling CEMS avg.	0.15	114.0
Sulfur Dioxide (SO_2) *Based on "low sulfur fuels". The SO_2 standards are also surrogate standards for sulfuric acid mist (SAM) emissions.*	24-hour rolling CEMS avg.	0.20	152.0
	30-day rolling CEMS avg.	0.10	
	12-month rolling CEMS avg.	0.06	
Opacity *Based on application of mechanical dust collectors and electrostatic precipitator.*	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) *Based on application of mechanical dust collectors and electrostatic precipitator.*	3-run test avg.	0.026	19.8
Volatile Organic Compounds (VOC) *Based on "good combustion practices".*	3-run test avg.	0.05	38.0
Lead (Pb) and Fluorides (Fl) *Based on "low lead/fluoride fuels".*	BACT is the use of fuels containing low levels of these compounds (bagasse, wood, distillate oil, and natural gas) and prospective removal with the fly ash by the mechanical dust collectors and electrostatic precipitators. The particulate matter standard shall also serve as a surrogate standard for lead.		

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:

Jeffrey J. Koerner — 10-22-03

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

Recommended By:

Trina L Vielhauer — 10/27/03

Trina Vielhauer, Chief (Date)
Bureau of Air Regulation

Approved By:

Michael G. Cooke — 10/27/03

Michael G. Cooke, Director (Date)
Division of Air Resources Management

SECTION IV. APPENDIX E
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 actual fuel flows. The permittee shall continuously monitor the fuel throughput rates based on the fuel flow monitors and calculate the actual heat input rates (24 hour average) for each fuel during each day of operation.

   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 SO_2 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.

SECTION IV. APPENDIX E
CONTINUOUS MONITOR REQUIREMENTS

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
Spreader stoker boiler with maximum heat input of 760 MMBtu/hour
ARMS EU ID No. _____ Cogeneration Boiler: ___ A ___ B ___ C

Unit Operation in Calendar Quarter
_____ 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
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)

Auxiliary Fuels
Pipeline natural gas
Distillate oil (≤ 0.05% sulfur by weight)

Pollutant Monitored ***(Check one.)***
_____ CO _____ NOx _____ SO2 _____ Opacity

Calendar Quarter of Operation Covered ***(Check one.)***
___ 1 ___ 2 ___ 3 ___ 4 for year _____

Continuous Monitor Information
Manufacturer: _____
Model No. _____
Date of last certification or audit: _____

Emission Standards
_____ lb/MMBtu of heat input, 24-hour rolling average
_____ lb/MMBtu of heat input, 30-day rolling average
_____ lb/MMBtu of heat input, 12-month rolling average
≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity

Emission Data Summary

1. Duration of excess emissions in reporting period due to:
   a. Startup/shutdown ..... _____
   b. Control equipment problems ..... _____
   c. Process problems ..... _____
   d. Other known causes ..... _____
   e. Unknown causes ..... _____
2. Total duration of excess emissions ..... _____
3. [Total duration of excess emissions] 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.

CMS Performance Summary

1. CMS downtime in reporting period due to:
   a. Monitor Equipment Malfunctions ..... _____
   b. Non-Monitor Equipment Malfunctions ..... _____
   c. Quality Assurance Calibration ..... _____
   d. Other Known Causes ..... _____
   e. Unknown Causes ..... _____
2. Total CMS Downtime ..... _____
3. [Total CMS Downtime] x (100%) ..... _____
   [Total source operating time]

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.

APPENDIX II Current Air Title V Permit

FILE

Department of Environmental Protection

Jeb Bush
Governor

South District
P.O. Box 2549
Fort Myers, Florida 33902-2549

Colleen M. Castille
Secretary

NOTICE OF FINAL TITLE V AIR OPERATION PERMIT REVISION

March 18, 2004

CERTIFIED MAIL 7003 1010 0004 1396 8393
RETURN RECEIPT REQUESTED

In the Matter of an
Application for Permit Revision by:

Mr. Ricardo A. Lima
Vice President and General Manager
Okeelanta Corporation
21250 U.S. Highway 27
South Bay, Florida 33493

FINAL Permit Project No.: 0990005-012-AV
Okeelanta Corporation
Palm Beach County

Dear Mr. Ricardo A. Lima:

Enclosed is the FINAL Permit, No. 0990005-012-AV, for the Title V Air Operation Revision. The purpose is to incorporate the terms and conditions of Construction Permits 0990005-005-AC, 0990005-008-AC, 0990005-009-AC/PSD-FL-169A, 0990005-010-AC, 0990005-013-AC, 0990332-013-AC/PSD-FL-196L, 0990332-014-AC/PSD-FL-196M, and 0990332-015-AC/PSD-FL-196N In accordance with Section II, Specific Condition 15. and Appendix SO-1 of the Title V Permit the revision removed the "old mill boilers", Emissions Units 003, 004, 005, 009, 010, 011, 012, and 013 from the Title V Permit. The application indicated that these emissions units are incapable of operation and will be dismantled.

The facility is located in Palm Beach County. This permit revision is issued pursuant to Chapter 403, Florida Statutes (F.S.). There were no comments received from Region 4, U.S. EPA, regarding the PROPOSED Permit.

Any party to this order (permit revision) has the right to seek judicial review of the permit revision pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and, by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Fort Myers, Florida.

Sincerely,

Jon M. Iglehart
Acting Director of
District Management

JMI/MGN/jw
Enclosures

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL TITLE V AIR OPERATION PERMIT REVISION (including the FINAL Determination and the FINAL Permit) was sent by certified mail before the close of business on March 18, 2004 to the persons listed or as otherwise noted:

Ricardo A. Lima, Okeelanta Corporation
James Meriwether, New Hope Power Partnership

The undersigned duly designated deputy agency clerk hereby certifies that a copy of this NOTICE OF FINAL TITLE V AIR OPERATION PERMIT REVISION was sent by U.S. Mail before the close of business on March 18, 2004 to the persons listed or as otherwise noted:

David A. Buff, P.E., Golder Associates, Inc.
Al Linero, Bureau of Air Regulation (INTERNET E-mail Memorandum)
James Stormer, Palm Beach County Air Program Administrator
USEPA, Region 4 (INTERNET E-mail Memorandum)

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.

Janice Wolfe 3/18/04
(Clerk) (Date)

FINAL Determination

Title V Air Operation Permit Revision
FINAL Permit Project No.: 0990005-012-AV
Revision to Title V Air Operation Permit No.: 0990005-003-AV
Okeelanta Corporation

I. Comment(s).

No comments were received from the USEPA during their 45-day review period of the PROPOSED Permit.

II. Conclusion.

In conclusion, the permitting authority hereby issues the FINAL Permit.

OKEELANTA CORPORATION
Okeelanta Corporation and New Hope Power Partnership Facilities
Facility ID Nos.: 0990005 and 0990332
Palm Beach County

Title V Air Operation Permit Revision

Final Permit No.: 0990005-012-AV
Revision to Title V Air Operation Permit No.: 0990005-003-AV

Permitting Authority:
State of Florida Department of Environmental Protection
Post Office Box 2549
Fort Myers, Florida 33902-2549
Telephone: (239) 332-6975
Fax: (239) 332-6969

Compliance Authority:
Palm Beach County Health Department
Post Office Box 29 (901 Evernia Street)
West Palm Beach, Florida 33402-0029
Telephone: 561-355-3136
Fax: 561-355-2442

Title V Air Operation Permit Revision
Final Permit No.: 0990005-012-AV

Revision to Title V Air Operation Permit No.: 0990005-003-AV

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IV. Attachments:

Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix AMP-001, Ash Management Plan
Appendix CO-001, Consent Order - OGC FILE No. 99-2079-50-AP
Appendix FMP-001, Fuel Management Plan
Appendix FMTP-001, Wood-Waste and Ash Inspection and Testing Plan
Appendix H-1, Permit History/ID Number Changes
Appendix OMP-001, Operation and Maintenance Plan for the Fly Ash Silo Baghouse
Appendix OMP-002, Operation and Maintenance Plan for the Mercury Control Agent Silo Baghouse(s)
Appendix OMP-003, Operation and Maintenance Plan for the Cogeneration Facility Boilers' Air Quality Control Systems (AQCSs)
Appendix R-1, Rule Applicability
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Appendix SS-1, Stack Sampling Facilities
Appendix SO-1, Simultaneous Operations for the Co-Generation and Sugar Mill Boilers
Appendix TV-4, Title V CONDITIONS (version dated 02/12/02)
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Figure 1, Summary Report – Gaseous and Opacity Excess Emission and Monitoring System Performance
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements

PERMITTEE:
Okeelanta Corporation
Post Office Box 86
South Bay, Florida 33493

Final Permit No.: 0990005-012-AV
Facility ID No.: 0990005 and 0990332
SIC No.: 2061, 2062, & 4911
Project: Title V Air Operation Permit Revision

This permit revision is being issued for the purpose of incorporating the terms and conditions of air construction permits, 0990005-005-AC, 0990005-008-AC, 0990005-009-AC/PSD-FL-169A, 0990005-010-AC, 0990332-013-AC/PSD-FL-196L, 0990332-014-AC/PSD-FL-196M, 0990332-015-AC/PSD-FL-196N. Construction Permit 0990005-005-AC involved construction of a sugar refinery production operation, process equipment, and a building addition. Construction Permit 0990005-008-AC authorized construction of a transshipment facility, including package lines, a sugar dryer/cooler, sugar grinder, and an increase in building size. The change in the process flow of baghouse E.U. 045 as mentioned above will also be incorporated. Construction Permit 009-AC/PSD-FL-196A allows Boiler No.16 to operate on natural gas or very low sulfur fuel oil. Construction Permit 0990005-010-AC involved the construction of a paint booth used to paint farm equipment, this permit and the modification, as mentioned above, that allows for flexibility in product substitution will be incorporated into this revision. Construction Permit 0990332-013-AC/PSD-FL-196L authorizes the power generation facility to use natural gas as a supplemental fuel. Construction Permit 0990332-014-AC/PSD-FL-169M 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 on chromium, copper, and arsenic. The permit also incorporated all previous permit modifications into a single document. Construction Permit 0990332-014-AC/PSD-FL-169N corrected minor typographical errors from Construction Permit 0990332-014-AC/PSD-FL-169M. In accordance with Section II, Specific Condition 15. and Appendix SO-1 of the Title V Permit the applicant also requested the removal of the "old mill boilers", Emissions Units 003, 004, 005, 009, 010, 011, 012, and 013 from the Title V Permit. The applicant has indicated that these emissions units are incapable of operation and will be dismantled. This permit revision is also being issued for the purpose of changing several Specific Conditions established in the Title V Air Operation Permit based on an Air Construction permitting action, No. 0990005-013-AC. Okeelanta Corporation's Sugarcane Processing (AIRS ID NO. 0990005), Sugar Refining (AIRS ID NO. 0990005) and New Hope Power Partnership (AIRS ID NO. 0990332) facilities are located approximately 6 miles south of South Bay on U.S. Highway 27, Palm Beach County, FL; UTM Coordinates Zone 17, 524.9 km East and 2940.1 km North; Latitude: 26^{o} 35' 00" North and Longitude: 80^{o} 45' 00" West.

This Title V Air Operation Permit Revision is issued under the provisions of Chapter 403, Florida Statutes (FS), and Florida Administrative Code (F.A.C.), Chapters 62-4, 62-210, and 62-213. The above named permittee is hereby authorized to operate the facilities shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:

Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix AMP-001, Ash Management Plan
Appendix CO-001, Consent Order - OGC FILE No. 99-2079-50-AP
Appendix FMP-001, Fuel Management Plan
Appendix FMTP-001, Wood-Waste and Ash Inspection and Testing Plan
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Appendix OMP-001, Operation and Maintenance Plan for the Fly Ash Silo Baghouse
Appendix OMP-002, Operation and Maintenance Plan for the Mercury Control Agent Silo Baghouse(s)
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Appendix RBL-001, RACT, BACT and LAER Determinations
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Table 2-1, Summary of Compliance Requirements

Effective Date: March 18, 2004
Renewal Application Due Date: April 24, 2005
Expiration Date: October 24, 2005

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Jon M. Iglehart
Acting Director of
District Management

JMI/MGN/jw

SECTION I. Facility Information.

Subsection A. Facility Description.

This facility consists of the sugarcane processing and sugar refining operations conducted by Okeelanta Corporation (AIRS ID No. 0990005) and the adjacent power generating operations conducted by Okeelanta Power L.P. (AIRS ID No.: 0990332) under the common control of the Okeelanta Corporation. The facilities have been combined into a single major Title V Source in accordance with Rule 62-210.200(126), F.A.C. based on the location of the two facilities.

The Title V Source includes Steam Generating Units, Materials Handling and Storage Operations, and Volatile Organic Liquid Handling and Storage Operations associated with the processing and refining of sugarcane and the cogeneration of power.

The Title V Source is classified as a modified-major source under the Prevention of Significant Deterioration (PSD) and New Source Review for Nonattainment Area (NSR-NAA) programs. The source includes existing, modified and new emissions units having undergone PSD review. The source is a major facility under the category "Fossil fuel fired boilers (or combinations thereof) totaling more than 250 million Btu/hr of heat input" as listed in Table 212.400-1, F.A.C. Facility-wide restrictions are addressed within Section II, Facility-wide Conditions.

The Title V Source is classified as a major VOC and NOx emitting facility and is subject to the Reasonably Available Control Technology (RACT) requirements of Rule 62-296.570, F.A.C. for the existing boilers. The RACT requirements are addressed within Section III, Emissions Unit Conditions.

The Title V Source includes several emissions units subject to New Source Performance Standards (NSPS) including 40 CFR 60 Subparts A, Da, Db, Ea, Kb and Y. The NSPS requirements are addressed within Section III, Emissions Unit Conditions.

The Title V Source does not include any emissions units subject to a National Emission Standard for Hazardous Air Pollutants (NESHAP). The source may have emissions of individual hazardous air pollutants (HAPs) at levels greater than 10 tons per year and emissions of total HAPs greater than 25 tons per year. Other HAPS, are listed as regulated based on a Best Available Control Technology (BACT) determination under the PSD program.

Subsection B. Summary of Emission Unit ID Nos. and Brief Descriptions

Subsection B. Summary of Emission Unit ID Nos. and Brief Descriptions for Okeelanta Corporation (AIRS ID No. 0990005)

E.U. ID No.	Status	Brief Description
001	N/A	Shutdown
002	N/A	Shutdown
003	N/A	Shutdown
004	N/A	Shutdown
005	N/A	Shutdown
006	N/A	Shutdown
007	N/A	Shutdown
008	N/A	Shutdown

E.U. ID No.	Status	Brief Description
009	N/A	Shutdown
010	N/A	Shutdown
011	N/A	Shutdown
012	N/A	Shutdown
013	N/A	Shutdown
014	Regulated	Mill Boiler No. 16
015	Regulated	Sugar Mill NSPS Storage Tank
016	Regulated	Sugar Mill NSPS Storage Tank
017	Regulated	Sugar Mill NSPS Storage Tank
018	Regulated	Central Vacuum System for the Transshipment Facility
019	Regulated	Packaging Lines
020	Regulated	Sugar Grinder and Hopper
021	Regulated	Central Dust Collection System No. 1 (Wet Rotoclone #1)
022	Regulated	Central Dust Collection System No. 2 (Wet Rotoclone #2)
023	Regulated	Cooler No. 1 (Cyclone No. 1)
024	Regulated	Cooler No. 2 (Cyclone No. 2)
025	Regulated	Fluidized Bed Dryer/Cooler
026	Regulated	Sugar Silo (S1101)
027	Regulated	Sugar Silo (S1102)
028	Regulated	Sugar Silo (S1103)
034	Regulated	Bulk Load-Out Operation
035	Unregulated	Transfer Bulk Load-Out Operation
036	Unregulated	Shop Operations
037	Unregulated	Sugar Mill Boiler House
038	Unregulated	Sugar Cane Dumping Area
039	Unregulated	Sugar Cane Processing Facility
040	Unregulated	Sugar Mill Fuel Farm
041	Unregulated	Sugar Mill Potable Water System
042	Unregulated	Sugar Mill Sewer Plant
043	Unregulated	Sugar Refinery
045	Unregulated	Main Sugar Receiver at Transshipment Facility
046	Unregulated	Sugar Grinder with Baghouse
047	Unregulated	Packaging lines to fill sugar packages
048	Regulated	Paint Booth for Farm Equipment

Summary of Emission Unit ID Nos. and Brief Descriptions for New Hope Power Partnership (AIRS ID No.: 0990332)

001	Regulated	Cogeneration Boiler No. 1
002	Regulated	Cogeneration Boiler No. 2
003	Regulated	Cogeneration Boiler No. 3
004	Regulated	Materials Handling and Storage Operations (Cogeneration Facility)
005	Unregulated	Cogeneration Facility NSPS Storage Tank

Please reference the Permit No., Facility ID No., and appropriate Emission Unit ID No., on all correspondence, test report submittal, applications, etc.

Subsection C. Relevant Documents

The documents listed below are not a part of this permit, however, they are specifically related to this permitting action.

These documents are provided to the permittee for information purposes only:
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History / ID Number Changes

These documents are on file with the permitting authority:

Title V Operating Permit
- Initial Title V Permit Application received June 17, 1996
- Amended Title V Permit Application received March 10, 2000
- Title V Permit Revision Application received November 4, 2002

Mill Boiler No. 16 (E.U. ID No. 014)
- AC50-191876 & PSD-FL-169, Initial Air Construction Permits
- AC50-191876 & PSD-FL-169, 2/18/93 Modification
- AC50-191876 & PSD-FL-169, 3/19/93 Modification
- AC50-191876 & PSD-FL-169, 3/7/94 Modification
- AO50-257065, Initial Operating Permit
- 0990005-009-AC/PSD-FL-196A, PSD Construction Permit

Sugar Mill NSPS Storage Tanks (E.U. ID Nos.: 015, 016, & 017)
- AC50-265485, Initial Air Construction Permit (After-the-Fact)

Central Vacuum System for the Transshipment Facility (E.U. ID No. 018)
- 0990005-001-AC, Initial Construction Permit (After-the-Fact)
- 0990005-008-AC, Construction Permit

Packaging Lines (E.U. ID No. 019)
- 0990005-001-AC, Initial Construction Permit (After-the-Fact)
- 0990005-008-AC, Construction Permit

Sugar Grinder & Hopper (E.U. ID No. 020)
- 0990005-001-AC, Initial Construction Permit (After-the-Fact)
- 0990005-008-AC, Construction Permit

Central Dust Collection System No. 1 (E.U. ID No. 021)
- 0990005-002-AC, Initial Construction Permit (After-the-Fact)
- 0990005-005-AC, Construction Permit

Central Dust Collection System No. 2 (E.U. ID No. 022)
- 0990005-002-AC, Initial Construction Permit (After-the-Fact)
- 0990005-005-AC, Construction Permit

Cooler No. 1 (Cyclone No. 1) (E.U. ID No. 023)
- 0990005-002-AC, Initial Construction Permit (After-the-Fact)
- 0990005-005-AC, Construction Permit

Cooler No. 2 (Cyclone No. 2) (E.U. ID No. 024)
0990005-002-AC, Initial Construction Permit (After-the-Fact)
0990005-005-AC, Construction Permit

Fluidized Bed Dryer/Cooler (E.U. ID No. 025)
0990005-002-AC, Initial Construction Permit
0990005-005-AC, Construction Permit

Sugar Silos S1101, S1102, & S1103 (E.U. ID Nos. 026, 027, & 28)
0990005-001-AC, Initial Construction Permit (After-the-Fact)
0990005-008-AC, Construction Permit

Materials Handling and Storage Operations (Cogeneration Facility) (E.U. ID No. 029)
AC50-219413 & PSD-FL-196, Initial Air Construction Permits

Cogeneration Facility Boilers (E.U. ID Nos. 030, 031, & 032)
AC50-219413 & PSD-FL-196, Initial Air Construction Permits
AC50-219413 & PSD-FL-196A-F, Permit Amendments
0990332-013-AC/PSD-FL-196L
0990332-013-AC/PSD-FL-196M
0990332-013-AC/PSD-FL-196N

Cogeneration Facility NSPS Storage Tank (E.U. ID No. 033)
AC50-219413 & PSD-FL-196, Initial Air Construction Permits

Bulk Load-out Operation (E.U. ID 034)
0990005-005-AC, Construction Permit

Transfer Bulk Load-Out Operation (E.U. ID 035)
0990005-005-AC, Construction Permit

Main Sugar Receiver at Transshipment Facility (E.U. 045)
0990005-008-AC, Construction Permit
0990005-013-AC, Construction Permit

Sugar Grinder with baghouse (E.U.46)
0990005-008-AC, Construction Permit

New Packaging lines with baghouse (E.U.047)
0990005-008-AC, Construction Permit

Paint Booth (E.U.048)
0990005-010-AC, Construction Permit
0990005-013-AC, Construction Permit

SECTION II. Facility Wide Conditions.

The following conditions apply facility-wide.

1. APPENDIX TV-4, TITLE V CONDITIONS, is a part of this permit.
{Permitting Note: APPENDIX TV-4, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided one copy when requested, or otherwise appropriate.}

2. **Not federally enforceable.** General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited: The permittee shall not 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.]

{Permitting note: An objectionable odor is defined as any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance.
[Rule 62-210.200, F.A.C.]

3. General Particulate Emission Limiting Standards: General Visible Emissions Standard.

(a) No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as No. 1 on the Ringelmann Chart (20 percent opacity).
[Rule 62-296.320(4)(b)1., F.A.C.]

(b) If the presence of uncombined water is the only reason for failure to meet the visible emissions standards given in Rule 62-296.320(4)1, F.A.C., such failure shall not be a violation of the rule.
[Rule 62-296.320(4)(b)3, F.A.C.]

(c) All visible emissions test performed pursuant to the requirements of Rule 62-296.320(b)(4)1, F.A.C. shall use EPA Method 9, and shall meet all applicable requirements of Chapter 62-297, F.A.C.
[Rule 62-296.320(4)(b)4, F.A.C.]

{Permitting Note: The general opacity standard applies in all cases except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit.}

4. Prevention of Accidental Releases (Section 112(r) of CAA).

(a) As required by Section 112(r)(7)(B)(iii) of the CAA and 40 CFR 68, the owner or operator shall submit a Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center.

(b) As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Department of Community Affairs (DCA), as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAA.

(c) The owner or operator shall submit, if applicable, the required annual registration fee to the DCA on or before April 1, in accordance with Part IV, Chapter 252, F.S. and Rule 9G-21, F.A.C.

Any required written reports, notifications, certifications, and data required to be sent to the DCA, should be sent to:

Department of Community Affairs
Division of Emergency Management
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100
Telephone: 850/413-9921, Fax: 850/488-1739

Any Risk Management Plans, original submittals, revisions, or updates to submittals, should be sent to:

RMP Reporting Center
Post Office Box 3346
Merrifield, VA 22116-3346
Telephone: 703/816-4434

Any required reports to be sent to the National Response Center, should be sent to:

National Response Center
EPA Office of Solid Waste and Emergency Response
USEPA (5305 W)
401 M Street, SW
Washington, D.C. 20460
Telephone: 1/800/424-8802

Send the required annual registration fee using approved forms made payable to:

Cashier
Department of Community Affairs
State Emergency Response Commission
255 Shumard Oak Boulevard
Tallahassee, FL 32399-2149

[Part IV, Chapter 252, F.S.: and, Rule 9G-21, F.A.C.]

5. Unregulated Emissions Units and/or Activities: Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

{Permitting note: Within the initial Title V permit application, the applicant grouped all insignificant and unregulated emissions units and activities into a single-unregulated emissions unit. The application did not identify any exempt activities.}

6. General Pollutant Emission Limiting Standards. Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions: The permittee shall allow no person to store, pump, handle, process, load, unload, or use in any process or installation, volatile organic compounds (VOC) or organic

solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.
[Rule 62-296.320(1)(a), F.A.C.]

{Permitting Note: As of July 1, 2000, the Department has not deemed necessary or ordered the use of any vapor emission control devices or systems for the Title V Source.}

7. When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one.
[Rule 62-213.440, F.A.C.]

8. The permittee shall submit all compliance-related notifications and reports required by this permit to South District Office of the Department of Environmental Protection and the Palm Beach County Health Department at:

Department of Environmental Protection
South District Office
Post Office Box 2549
Fort Myers, Florida 33902-2549
Telephone: (239) 332-6975
Fax: (239) 332-6969

Palm Beach County Health Department
Air Pollution Control Section
Post Office Box 29
West Palm Beach, Florida 33402-0029
Telephone: (561) 355-3136
Fax: (561) 355-2442

9. Any reports, data, notification, certifications, and requests required to be sent to the United States Environmental Protection Agency (EPA) should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch
Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303-8960
Telephone: 404/562-9155; Fax: 404/562-9163

10. Excess Emissions Requirements:

(a) Excess emissions resulting from startup, shutdown, or malfunction of any emission unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

(b) 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.
[Rule 62-210.700(4), F.A.C.]

(c) Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust the maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest.
[Rule 62-210.700(5), F.A.C.]

(d) In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted to the Compliance Authority in a quarterly report, if requested by the Permitting or Compliance Authority.
[Rule 62-210.700(6), F.A.C.]

{Permitting note: The permittee requested authorization for periods of excess emissions greater than 2 hours in any 24-hour period for specific emissions units within the Initial Title V application. The applicant has been advised that the request is outside the scope of the Title V program and has been instructed to obtain approval from the Department's Bureau of Air Regulation. Once approval is granted, the Title V permit can be revised to reflect the change. For the steam generators at the Co-Generation Facility the Department has authorized a longer duration as described in **Specific Condition F.19.** of this permit.}

11. Air Emissions Bubble: Within Attachment OC-FA-7 of the initial Title V application, the permittee notified the Permitting Authority of its intent to use an air emissions bubble to locate a temporary steam generator at the source. The permittee's intent would be to use the temporary steam generator during major malfunctions of the existing steam generators. The permittee shall submit a complete application and receive a permit in accordance with the requirements of Rule 62-212.710, F.A.C. prior to implementing any changes.
[Rule 62-210.300(1) and 62-212.710, F.A.C.]

12. Compliance Plan. Based on the application, Emissions Units 014, 015, 016, 017, 018, 021, 022, 023, 024, 025, 026, 027, 028, 029, 034, 035, 045, 046, 047, and 048 were not in compliance. Appendix CP-1, Compliance Plan, is a part of this permit.
[Rule 62-213.440(2), F.A.C. Effective Date: March 18, 2004]

13. Statement of Compliance: The annual statement of compliance pursuant to Rule 62-213.440(3)(a)2.,F.A.C., shall be submitted to the Department and EPA within 60 (sixty) days after the end of the calendar year using DEP Form No. 62-213.900(7), F.A.C.
[Rules 62-213.440(3) and 62-213.900, F.A.C.]

{Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2. & 3., F.A.C. (see Condition 51. of Appendix TV-4, TITLE V CONDITIONS)}

14. Facility Wide Recordkeeping and Monitoring Requirements: The following facility wide recordkeeping and monitoring requirements apply:
[Rule 62-213.440(1)(b), F.A.C]

(a) The permittee shall generate a daily operations report for each day that a regulated emissions unit operates.

(b) The permittee shall monitor and record the daily electrical power generation (1-hour block averages) from the cogeneration facility for each day of operation.

(c) The permittee shall monitor and record the steam production rates of the sugar mill boilers (24-hour block average, 8:00 a.m. to 8:00 a.m.) and the cogeneration facility boilers (24-hour average) for each day of operation.

(d) The permittee shall monitor and record the fuel oil consumption rates for the sugar mill boilers on a daily basis for each day of operation.

(e) The permittee shall monitor the type of fuels fired in the mill boilers and the cogeneration boilers for each day of operation.

15. Facility Wide Operating Restrictions

A. The following multi-unit operating restrictions apply to Emissions Units 001, 002, and 003 (Cogeneration Boilers) and the Cogeneration Facility (Facility ID 0990332).
[PSD-FL-196 and AC50-219413, as amended]

(a) Electrical power generation from the cogeneration facility shall not exceed 74.9 (gross) megawatts on any 1-hour average, except during emission compliance tests.

(b) Total heat input to Emissions Units 001, 002, and 003 shall not exceed 11.5×10^{12} Btu/year.

16. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information.
[Rule 62-213.420(4), F.A.C.]

SECTION III. Emissions Units and Conditions.

Subsection A. This section addresses the following emissions unit.

E.U ID No.	Emission Unit Description
014	Mill Boiler No. 16 is a 211/202 MMBtu per hour package boiler fired with natural gas/distillate oil.

Description: This unit is Babcock and Wilcox Model No. FM 120-97 package boiler with a maximum steam production rate of 150,000 pounds per hour (24-houraverage). The design heat release rate for this unit is greater than 70,000 BTU/hour-ft^3.

Fuels: This unit is fired with pipeline-quality natural gas or very low sulfur distillate oil.

Capacity: The heat input rate is 211 MMBtu per hour when firing natural gas, which is approximately 0.207 million cubic feet of gas per hour based on a heat content of 1020 MMBtu per million SCF. The heat input rate is 202 MMBtu per hour when firing very low sulfur distillate oil, which is approximately 1433 gallons per hour based on a heat content of 141 MMBtu per thousand gallons.

Controls: The efficient combustion of clean fuels minimizes emissions of CO, PM/PM10, SO2, and VOC. Emissions of NOx are reduced with low NOx burners and flue gas recirculation (approximately 15%).

Stack Parameters: Exhaust gases exit a 75 feet tall stack that is 5.0 feet in diameter with a volumetric flow rate of approximately 88,200 acfm at 410° F.

{Permitting notes: BACT: The emissions standards specified for this unit represent determinations of the Best Available Control Technology (BACT) for nitrogen oxides (NOx), particulate matter (PM/PM10), and sulfur dioxide (SO2). Appendix BD of this permit lists the final BACT determinations for this project. [Rules 62-212.400(BACT) and 62-296.406 (BACT for small boilers), F.A.C.] The boiler has been reviewed under the PSD Program for sulfur dioxide (SO_2) and nitrogen oxides (NOx), and as a synthetic minor source for particulate matter (PM), volatile organic compounds (VOC), and carbon monoxide (CO). As a synthetic minor source of VOC and NOx, the unit is subject to the Reasonably Available Control Technology (RACT) emission limiting standards of Rule 62-296.570, F.A.C. The unit is classified as a new facility under the New Source Performance Standards (40 CFR 60 Subpart Db) and Rule 62-296.406, F.A.C., Fossil Fuel Fired Steam Generators with less than 250 MMBtu/hr of Heat Input.}

A.1. Permitted Capacity. The maximum design heat input rates to the boiler are 211 MMBtu per hour when firing natural gas and 202 MMBtu per hour when firing very low sulfur distillate oil. The maximum steam production rate shall not exceed 150,000 pounds per hour based on a 24-hour block average of the last 24 boiler operating hours. The boiler shall be equipped with integrating fuel flow meters to monitor the consumption of natural gas and distillate oil. The boiler shall be equipped with instruments to continuously monitor the steam production rate (pounds per hour), steam temperature (° F), and steam pressure (psig).
[Rule 62-210.200(PTE), F.A.C. and Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

A.2. Authorized Fuel. The boiler shall fire only pipeline-quality natural gas or very low sulfur No. 2 distillate oil with a maximum sulfur content of 0.05% sulfur by weight.
[Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C. and Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

A.3. Hour of Operation. The hours of operation are not limited (8760 hours per year). The boiler shall fire no more than 10,000,000 gallons of very low sulfur distillate oil during any consecutive 12 months.
[Rule 62-210.200(PTE), F.A.C. and Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

A.4. Low NOx Burners: The permittee is authorized to install, tune, maintain and operate a modified burner system to include Coen low-NOx burners (or equivalent) with flue gas recirculation capable of achieving the emissions standards specified in this permit. The system shall be capable of firing pipeline-quality natural gas and very low sulfur distillate oil.
[Rule 62-212.400(BACT), F.A.C. and Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

Emission Limitations and Standards

A.5. Emissions from the boiler shall not exceed the following limits for carbon monoxide (CO), nitrogen oxides (NOx), opacity, particulate matter (PM/PM10), sulfur dioxide (SO2), and volatile organic compounds (VOC). *(Permitting Note: Appendix BD lists the BACT determinations for this project.}*

Pollutant	Natural Gas Firing		Distillate Oil Firing		Rule Citation (F.A.C.)
	lb/MMBtu	lb/hour [g]	lb/MMBtu	lb/hour [g]	
CO [a]	0.10	21.1	0.11	22.2	Avoid Rule 62-212.400 (BACT)
NOx [b]		12.7		24.2	
24-hour block	0.10	NA	0.20	NA	Rule 62-212.400 (BACT)
30-day rolling	0.06	NA	0.12	NA	Rule 62-212.400 (BACT)
30-day rolling	0.20	NA	0.20	NA	NSPS Subpart Db
Opacity [c]	10% opacity, except for one 6-minute period per hour that does not exceed 27%opacity				Rule 62-212.400 (BACT)
PM/PM10 [d]	Efficient combustion of natural gas		Firing of very low sulfur distillate oil		Rule 62-212.400 (BACT), and Rule 62-296.406 (BACT)
SO2 [e]	Firing of natural gas		Firing of very low sulfur distillate oil		Rule 62-296.406 (BACT)
VOC [f]	Efficient combustion of natural gas		Efficient combustion of very low sulfur distillate oil		Avoid Rule 62-212.400 (BACT)

a. Compliance with the CO standards shall be based on the average of three test runs conducted at permitted capacity as determined by EPA Method 10.

b. As determined by the certified NOx CEMS, compliance with the 24-hour NOx standards shall be based on the block average of the last 24 boiler operating hours. The 30-day average NOx emissions shall be calculated at the end of each steam generating unit operating day from the measured hourly NOx emission rates for the preceding 30 steam generating unit operating days.

c. The opacity standard is based on a 6-minute block average, as determined by the certified continuous opacity monitoring system (COMS). EPA Method 9 may also be used to determine compliance with the opacity standard.

d. When firing natural gas, the expected maximum PM emissions are 0.002 lb/MMBtu (0.4 lb/hour). When firing very low sulfur distillate oil, the maximum expected PM emissions are 0.03 lb/MMBtu (6.1 lb/hour). Compliance with the CO and opacity standards shall serve as indicators of good combustion. No testing is required.

e. The fuel specifications of this permit effectively limit the potential SO2 emissions. No testing is required. When firing natural gas, the expected maximum SO2 emissions are 0.001 lb/MMBtu (0.2 lb/hour). When firing very low sulfur distillate oil, the expected maximum SO2 emissions are 0.06 lb/MMBtu (12.1 lb/hour).

f. When firing natural gas, the expected maximum VOC emissions are 0.03 lb/MMBtu (6.3 lb/hour). When low sulfur distillate oil, the expected maximum VOC emissions are 0.03 lb/MMBtu (6.1 lb/hour). Compliance with the CO and opacity standards shall serve as indicators of good combustion. No testing is required.

Maximum hourly emissions are based on the emissions standards and the maximum allowable heat input from each fuel.
[Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

Excess Emissions

A.6. Excess Emissions – Prohibited**.** Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such emissions shall be included in the calculation of the continuous compliance averages for opacity and NOx emissions.
[Rule 62-210.700(4), F.A.C. and Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

A.7. Startup, Shutdown and Malfunction Plan: n accordance with Rule 62-210.700(5), F.A.C., the following permit conditions define alternate opacity standards and allow the exclusion of NOx monitoring data during specified periods of startup, shutdown, and unavoidable malfunction. These conditions shall only apply if operators employ the best operational practices to minimize the amount and duration of emissions during these incidents.

a. *Visible Emissions*: Opacity shall be recorded by the COMS during all episodes of startup, shutdown and malfunction. During startup and shutdown, visible emissions shall not exceed 20% opacity except for one 6-minute period per hour that does not exceed 27% opacity, based on 6-minute block averages.

b. *CEM System Data Exclusion*: NOx emissions data shall be recorded by the CEMS during all episodes of startup, shutdown and malfunction. When determining compliance with the 24-

hour block and 30-day rolling NOx BACT standards, up to two 1-hour averages due to startups, shutdowns, or unavoidable malfunctions may be excluded from each 24-hour period. The 30-day rolling NOx NSPS standard applies at all times and data may not be excluded.

c. *Notification*: Within three days of recording emissions in excess of a standard, the permittee shall notify the Compliance Authority by telephone or facsimile.

These conditions are established in place of the provisions specified in Rule 62-210.700(1), F.A.C.

[Design; Rules 62-4.070(3), 62-4.130, 62-210.700(5), and 62-212.400 (BACT), F.A.C. and [Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

Test Methods and Procedures

A.8. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the boiler shall be tested to demonstrate compliance with the CO emission standards for each authorized fuel that is fired for more than 400 hours. Data collected by the certified continuous opacity and NOx monitors shall be summarized for each CO test run and submitted as part of each test report. Compliance with the opacity and NOx standards are determined by data collected from the continuous monitors and separate annual performance tests for these pollutants are not required. Emissions of CO and NOx shall be reported in terms of "pounds per MMBtu of heat input" and "pounds per hour" using the appropriate F-factors for each fuel. The annual test report shall also indicate the date the annual NOx RATA was performed and summarize the results. If no fuel is fired for more than 400 hours, the permittee shall submit a summary of the opacity and NOx emissions data within 30 days of the end of the federal fiscal year.
[Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C. and Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

A.9. Test Methods: As required, tests shall be performed in accordance with the following reference methods.

EPA Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources • The method shall be based on a continuous sampling train.

In addition, it may be necessary to perform EPA Methods 1 through 4 as part of the above test methods. These test methods are specified in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used to demonstrate compliance unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. Other applicable testing requirements are included in Appendix SC of the permit.
[Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A, and Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

Continuous Monitoring Requirements

A.10. NOx CEMS: The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) to measure and record the emissions of NOx from the boiler in a manner sufficient to demonstrate continuous compliance with the emission standards of this permit. The emission rate (pounds per MMBtu) shall be calculated by the CEMS using F-factors that are appropriate for each fuel fired. For purposes of determining compliance with the emission standards of this permit, missing or excluded data shall not be substituted. The monitoring system shall be installed, calibrated, and properly functioning prior to the initial emissions compliance tests and shall be used to demonstrate continuous compliance with the specified NOx emissions standards. [Rule 62-212.400(BACT), F.A.C.]

a. *Monitor Certification.* The NOx CEMS shall: be certified in accordance with Performance Specification 2 in Appendix B of 40 CFR 60; comply with the monitoring requirements of 40 CFR 60.13; have dual span capability with a "low" span no greater than "0.18 pounds per MMBtu" (or equivalent) and a "high" span no greater than 0.60 pounds per MMBtu" (or equivalent); and comply with the quality assurance procedures in Appendix F of 40 CFR 60. The required RATA test shall be performed prior to the initial emissions compliance tests using EPA Method 7E of Appendix A in 40 CFR 60.

b. *Data Collection.* The NOx CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour. Each hourly value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages.

c. *Emission Rate*: Compliance with the 24-hour NOx standards shall be based on the average of the CEMS data collected during each block of 24 boiler-operating hours. Data for each 24-hour block shall be exclusive from data in other 24-hour blocks. A "boiler operating hour" means a 1-hour block of time during which the boiler combusted any fuel. It is not necessary for fuel to have been combusted continuously for the entire hour. Compliance with the 30-day NOx standards shall be based on the average of the CEMS data collected during the last 30 boiler operating days, rolled for each new boiler operating day in accordance with 40 CFR 60.49a. A "boiler operating day" means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the boiler. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

d. *Data Exclusion.* NOx emissions data shall be recorded by the CEMS during all episodes of startup, shutdown, and malfunction. Individual NOx hourly average emission rate values may be excluded only in accordance with Condition No. 11. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction.

{Permitting Note: Compliance with these requirements will ensure compliance with other applicable CEMS requirements, such as: Rule 62-297.520, F.A.C.; 40 CFR Part 51, Appendix P; 40 CFR 60.7(a)(5); 40 CFR 60.13; 40 CFR 60.48b; 40 CFR 60.49b; 40 CFR 60, Appendix B; and 40 CFR 60, Appendix F.}
[40 CFR 60.48b; Rule 62-212.400(BACT), F.A.C. and Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

A.11. Opacity COMS: The permittee shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) to measure and record the opacity from the boiler in a manner sufficient to demonstrate continuous compliance with the emission standards of this permit. The COMS shall: be certified in accordance with Performance Specification 1 in Appendix B of 40 CFR 60; comply with the monitoring requirements of 40 CFR 60.13; and comply with the quality assurance procedures in Appendix F of 40 CFR 60. It shall be installed and functioning properly prior to the initial emissions compliance tests. The COMS shall be used to demonstrate continuous compliance with the corresponding opacity standards specified in this permit based on a 6-minute average.
[40 CFR 60.48b; Rule 62-212.400(BACT), F.A.C. and Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

A.12. Monitor Availability: The availability of each required monitor shall not be less than 95% in any calendar quarter. The quarterly report required in Appendix XS shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall submit a report to each Compliance Authority that identifies 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. The Department may require additional testing for failure to maintain at least 95% monitor availability. [40 CFR 60.48b; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C. and Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

Recordkeeping and Reporting Requirements

A.13. Fuel Sulfur Records: Compliance with the distillate oil sulfur limit shall be demonstrated by taking an initial sample, analyzing the sample for fuel sulfur, and reporting the results with the initial emissions compliance test report. Sampling and analyzing the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent distillate oil delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

[Rules 62-4.070(3), 62-4.160(15), and 62-297.310(7)(b), F.A.C. and Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

A.14. Monthly Operations Summary: By the seventh calendar day of each month, the permittee shall record the following information in a written or electronic log.

- Hours and gallons of distillate oil firing for the previous month and the previous 12 months;
- Hours and SCF of natural gas firing for the previous month and the previous 12 months; and
- Maximum and average steam production (pounds per hour) for the previous month.

Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request from the Department or a Compliance Authority.
[Rules 62-4.160(15) and 62-4.070(3), F.A.C. and Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

A.15. Continuous Monitor System Quarterly Report: Within thirty (30) days following each calendar quarter, the permittee shall submit a report to each Compliance Authority summarizing emissions in excess of a permit standard, periods of data exclusion, and monitor availability for the previous calendar quarter. The report shall also identify and describe any malfunctions causing emissions in excess of a permit standard. The report shall be submitted for each required monitoring system and shall generally follow the NSPS format provided in Appendix XS of this permit. If necessary, the report shall include a corrective action plan to achieve at least 90% monitor availability.
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., 40 CFR 60.7, and Construction Permit 0990005-009-AC/PSD-FL-196A, dated October 30, 2001, Effective Date: March 18, 2004]

A.16. Common Conditions: This emissions unit is also subject to **Specific Conditions H.1. through H.20.** contained in **Subsection H. Common Conditions.**

Subsection B. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-015	Volatile Organic Liquid Storage Tank (Sugar Mill)
-016	Volatile Organic Liquid Storage Tank (Sugar Mill)
-017	Volatile Organic Liquid Storage Tank (Sugar Mill)
-033	Volatile Organic Liquid Storage Tank (Cogeneration Facility)

Emissions Units Details

Emissions Units 015, 016, and 017 are fixed-cone-roof double-walled storage tanks each having an approximate capacity of 29,500 gallons. Emissions Unit 033 has a capacity of approximately 50,000 gallons. The tanks were constructed after July 23, 1984 and are subject to specific recordkeeping requirements of 40 CFR 60 Subpart Kb. The tanks store No. 2 distillate fuel oil for Mill Boiler No.16 (E.U. ID Nos. 15, 16, & 17) and for the Co-Generation Boilers (E.U. ID No. 33).

{Permitting notes: The units are classified as new facilities under the New Source Performance Standards (40 CFR 60 Subpart Kb) and subject to the recordkeeping requirement of 40 CFR 60 Subpart Kb.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

{Permitting note: The operating restrictions which are identified as "Not Federally Enforceable" have been placed in the permit to identify the capacity of the unit for purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity, to establish emission limits, and to aid in determining future rule applicability.}

B.1. Permitted Capacity. The permittee shall not allow, cause, suffer, or permit the operation of Emissions Units 015, 016, and 017 in excess of the following total capacity without prior authorization from the Permitting Authority:

(a) Annual Throughput: 9,344,600 gallons (12-month rolling total) of No. 2 distillate oil.

[Rules 62-4.160(2), 62-210.200(228), 62-210.300, F.A.C. and Construction Permit AC50-265485 dated May 22, 1995]

B.2. Methods of Operation: The permittee shall not allow, cause, suffer or permit any change in the method of operation of Emissions Units 015, 016, and 017 without prior authorization from the Permitting Authority. The authorized methods of operation include the following:

(a) Fuel Type(s): The permittee is authorized to store No. 2 distillate oil.

(b) Fuel Vapor Pressure: The permittee shall not store or handle any fuels within the units with a maximum true vapor pressure greater than 15.0 kPa (2.176 psi).
[Construction Permit AC50-265485 dated May 22, 1995 and 40 CFR 60.110b(c)]

[Rules 62-4.160(2), 62-210.200(228), 62-210.300, F.A.C., 40 CFR 60.110b(c), and AC50-265485 dated May 22, 1995]

B.3. Hours of Operation: The permittee is authorized to operate the units continuously.
[Construction Permit AC50-265485 dated May 22, 1995]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.4. Volatile Organic Compounds (VOC): The permittee shall not allow VOC emissions greater than 217 pounds per year from Emissions Units 015, 016, and 017.
[Construction Permit AC50-265485 dated May 22, 1995]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

Compliance Demonstrations and Periodic Monitoring

B.5. Compliance Demonstrations: The permittee shall demonstrate compliance with the emissions limitation of Specific Condition **E.4.** based on record keeping and emission estimates calculated using the latest version of AP-42 or the TANKS Software Package.
[Rule 62-297.310(7), F.A.C.]

B.6. Operating Parameters: The permittee shall implement the following periodic monitoring requirements to ensure compliance with the Specific **Conditions B.1**, **B.2.** and **B3.** of this permit:

(a) Monthly Throughput: The permittee shall monitor and record the monthly throughput of volatile organic liquids through each tank.

(b) Volatile Organic Liquid Types: The permittee shall monitor and record the type (Name and True Vapor Pressure at 80^{o}F) of volatile organic liquids stored and handled in each tank.

[Rule 62-213.440(1)(b), F.A.C and Construction Permit AC50-265485 dated May 22, 1995]

New Source Performance Standards (NSPS)

{Permitting note: All the units are subject to the recordkeeping requirements of 40 CFR 60 Subpart Kb provided the permittee complies with the requirements of 40 CFR 60.110b, Applicability.}

B.7. 40 CFR 60 Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced after July 23, 1984: The permittee shall comply with the applicable requirements of 40 CFR 60 Subpart Kb contained in Appendix NSPS-Kb. Specifically:

(a) 40 CFR 60.110b, Applicability,

(b) 40 CFR 60.111b, Definitions,

(c) 40 CFR 60.116b, Monitoring of Operations

[40 CFR 60.40b(a), Rule 62-204.800(7)(b), F.A.C.]

B.8. Common Conditions: This emissions unit is also subject to **Specific Conditions H.12. , H.18, and H.19.** contained in Subsection **H. Common Conditions.**

Subsection C. This section addresses the following emissions units.

E.U. ID No.	Trans-Shipment Facility Brief Description
-018	Central Vacuum System for Trans-Shipment Facility
-019	Packaging Lines
-020	Sugar Grinder & Hopper
-026	Sugar Silo S1101
-027	Sugar Silo S1102
-028	Sugar Silo S1103

Emissions Units Details

Central Vacuum System, designated Emissions Unit 018, used periodically for house keeping purposes. The system includes various pick-up points throughout the Trans-Shipment Facility and is equipped with a cyclonic separator followed by a baghouse manufactured by Ross Cook (Model No. RC30HBFBX-PJ). The baghouse exhausts through an 8' stack. The system also includes a new baghouse to control a new powdered sugar dryer and cooler, a new sugar grinder with baghouse and new packaging lines with baghouse.

Packaging Lines, designated Emissions Unit 019, consisting of ten (10) packaging lines, which are used to package sugar in bags ranging in size from 5 pounds to several hundred pounds. The packaging lines are connected to a single baghouse manufactured by MAC Filter (Model 55AVSC640). The baghouse exhausts through a 27' stack. The Emissions Unit also includes several new packaging lines with baghouse.

Sugar Grinder and Hopper, designated Emissions Unit 020 used to reduce the sugar solids to a desired particle size including powered sugar. The grinder has a design capacity of 4 tons per hour. The grinder and interconnected hopper are connected to baghouse manufactured by Reimelt Corporation. The baghouse exhausts through a 39' stack. The Emissions Unit also includes a new baghouse to control a new powdered sugar dryer and cooler and a new sugar grinder with baghouse.

Sugar silo numbers S1101, S1102, and S1103, designated Emissions Units 026, 027, and 028, used to store and handle refined sugar prior to packaging and/or grinding. Each silo has a net capacity of 4,600 cubic feet, a diameter of 12 feet, a height of 68 feet and is equipped with a baghouse manufactured by Reimelt Corporation (Model No. JF795-14P-7.5-5). Each baghouse exhausts through an individual 65' stack.

{Permitting note: The units are classified as synthetic minor sources under the PSD Program and considered as "Regulated Emissions Units" because they are subject to unit-specific federally enforceable emission limitations for particulate matter and visible emissions.}

Construction Restrictions

The following specific conditions apply to the emissions units listed above:

{Permitting notes: The following construction restrictions are "Not Federally Enforceable" and have been placed in the permit to identify the capacity of the unit to aid in determining future rule

applicability. For the Refinery Operations, activities, which are completely enclosed and vented within the building, are not classified as air pollution sources.}

C.1. Design Specifications: The permittee shall not allow, cause, suffer or permit changes to the following Air Quality Control System (AQCS) specifications without prior authorization from the Permitting Authority.

E.U. ID No.	**Design Flows[(1)]**		**AQCS Fabric Filter Specifications[(1)]**			**Potential Emissions[(1)]**	
	(ACFM)	**(DSCFM)**	**Filtering Material**	**Filtering Area**	**A/C Ratio**	**gr/scf[(2)]**	**lb/hr[(2)]**
-018	284	280	PF Bags	72	3.9	0.01	0.024
-019	10,000	9,868	PP Bags	3,520	2.84	0.01[(3)]	0.857
-020	3,000	2,960	GTP Bags	800	3.75	0.0005	0.013
-026	521	500	SPF Bags	81 sq. ft.	6.17	0.02	0.0857
-027	521	500	SPF Bags	81 sq. ft.	6.17	0.02	0.0857
-028	521	500	SPF Bags	81 sq. ft.	6.17	0.02	0.0857

A/C Ratio – Air to Cloth Ratio (dscfm/sq. ft)
N/A – Not Applicable
PF – Polyfelt
Specifications
PP – Polyester Pleated
GTP – Gore-Tex Polyester
SPF – Standard Polyester Felt
PE 550 – Filter Quality per Manufacturer's

(1) - Not Federally Enforceable.
(2) - Potential Emissions include PM and PM10.
(3) - Units are in grains per actual cubic foot.

[Rules 62-4.160(2), 62-210.200(228), and 62-210.300, F.A.C.]

Essential Potential to Emit (PTE) Parameters

{Permitting note: The operating restrictions which are identified as "Not Federally Enforceable" have been placed in the permit to identify the capacity of the unit for purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity, to establish emission limits, and to aid in determining future rule applicability.}

C.2. Permitted Capacities: The permittee shall not allow, cause, suffer or permit the operation of a unit in excess of the following capacities without prior authorization from the Permitting Authority.

E.U. ID No.	Process Rates		
	TPH	Tons/day	Regulation/Permit
-018	N/A	N/A	Not Federally Enforceable, 0990005-001-AC
-019	81.5(1)	865	Federally Enforceable, 0990005-008-AC
-020	4(2)	N/A	Not Federally Enforceable, 0990005-001-AC
-026	87.5	N/A	Not Federally Enforceable, 0990005-001-AC
-027	87.5	N/A	Not Federally Enforceable, 0990005-001-AC
-028	87.5	N/A	Not Federally Enforceable, 0990005-001-AC
Note(s): (1) Maximum Loading to all packaging lines. (2) Daily Average.			

[Rules 62-4.160(2), 62-210.200(228), and 62-210.300, F.A.C. and Construction Permit 0990005-008-AC dated May 10, 2001, Effective Date: March 18, 2004]

C.3. Methods of Operation: The permittee shall not allow, cause, suffer, or permit any change in the method of operation without prior authorization from the Permitting Authority. The authorized methods of operation include the following:

(a) *Central Vacuum System*: The permittee is authorized to use the system for housekeeping purposes and vent the exhaust to the outside air through the AQCS. The system has no restrictions on the number or types of pick-up points. [Not Federally Enforceable; Construction permit 0990005-001-AC dated January 24, 1996]

(b) *Packaging Lines*: The permittee is authorized to operate a total of ten (10) packaging lines and vent the exhaust to the outside air through the AQCS. The permittee may operate all ten (10) packaging lines simultaneously at the maximum feed rate specified in **Specific Condition C.2**. [Federally Enforceable; Construction Permit 0990005-008-AC dated May 10, 2001]

(c) *Sugar Grinder & Hopper*: The permittee is authorized to operate a sugar grinder and associated interconnected hopper and vent the exhaust to the outside air through the AQCS. [Not Federally Enforceable; Construction Permit 0990005-001-AC dated January 24, 1996]

(d) *Storage Silos*: The permittee is authorized to unload sugar from two refinery trucks at a time into a single silo using mechanical conveyors and vent the exhaust to the outside air through the AQCS. [Not Federally Enforceable; Construction Permit 0990005-001-AC dated January 24, 1996]

[Rules 62-4.160(2), 62-210.200(228), and 62-210.300, F.A.C., Effective Date: March 18, 2004]

C.4. Hours of Operation: The permittee is authorized to operate the Central Vacuum System, Packaging Lines, Sugar Grinder and Hopper, and Storage Silos continuously
[Construction Permit 0990005-001-AC dated January 24, 1996].

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

C.5. Visible Emissions: The permittee shall not allow visible emissions greater than 5 percent opacity (6-minute average) from the Central Vacuum System (E.U. ID No. 018), the Packaging Lines (E.U. ID No. 019), or the Storage Silos (E.U. ID Nos. 026, 027, & 028) baghouse exhausts.
[Rule 62-297.620(4), F.A.C., Construction Permits 0990005-001-AC dated January 24, 1996 and 0990005-008-AC dated May 10, 2001, Effective Date: March 18, 2004]

C.6. Particulate Matter (PM): The permittee shall not allow particulate matter emissions from each unit greater than the following without prior authorization from the Permitting Authority:

E.U. ID No.	**Allowable Emission Tons Per Year (TPY)**	**Regulation/Permit**
-018	0.105	0990005-008-AC
-019	6.009	0990005-008-AC
-020	4.115	0990005-008-AC
-026	0.375	0990005-008-AC
-027	0.375	0990005-008-AC
-028	0.375	0990005-008-AC
Total	11.352	0990005-008-AC

[Rules 62-4.160(2), 62-210.200(228), and 62-210.300, F.A.C. and Construction Permits 0990005-001-AC, dated January 24, 1996 and 0990005-008-AC, dated May 10, 2001, Effective Date: March 18, 2004]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

C.7. Visible Emissions: All visible emissions tests performed pursuant to the requirements of this permit shall comply with the following provisions:

(a) *Test Method*: The test method for visible emissions shall be EPA Method 9, incorporated in Rule 62-297.401(9) F.A.C. and the required minimum period of observation for a compliance test shall be thirty (30) minutes. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur.
[Rules 62-297.401 and 62-297.310(4)(a)2., F.A.C., and Construction Permits 0990005-001-AC dated January 24, 1996 and 0990005-008-AC, dated May 10, 2001]

(b) *Test Procedures*: Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[Construction Permits 0990005-001-AC dated January 24, 1996 and 0990005-008-AC, dated May 10, 2001, Effective Date: March 18, 2004]

C.8. Particulate Matter (PM): All particulate matter tests performed pursuant to the requirements of this permit shall comply with the following:

(a) *Test Method*: The test methods for particulate matter shall be EPA Methods 1, 2, 3, 4, and 5 described in 40 CFR 60, Appendix A, Rules 62-297.401(1) through (5), F.A.C.
[Rule 62-297.401, F.A.C., Construction Permits 0990005-001-AC dated January 24, 1996]

(b) *Test Procedures*: The test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[Rule 62-297.401, F.A.C.]

Compliance Demonstrations and Periodic Monitoring

C.9. Compliance Demonstrations: The permittee shall have a formal compliance test conducted for visible emissions from each emissions unit annually during each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, for the following pollutants.
[Rule 62-297.310(7), F.A.C]

C.10. Waiver of Compliance Test Requirements: For particulate matter (PM), the Permitting Authority has waived the particulate matter compliance test requirements and specified the alternative standard of 5% opacity (Specific Condition **C.5.**). If the Compliance Authority has reason to believe that either the design specifications of Specific Condition **C.1.** or the emissions rates are not being met, it shall require that compliance be demonstrated by the test methods specified in Specific Condition **C.8.**
[Rule 62-297.620(4), F.A.C., Construction Permits 0990005-001-AC dated January 24, 1996 and 0990005-008-AC, dated May 10, 2001, Effective Date: March 18, 2004]

C.11. Operating Parameters: The permittee shall implement the following periodic monitoring requirements to ensure compliance with the Specific Conditions **C.2.** and **C.3.** of this permit:

(a) *Central Vacuum System (E.U. ID No. 018)*: None

(b) *Packaging Line (E.U. ID No. 019)*: The permittee shall monitor and record the date, amount of sugar packaged, number of packaging lines operated, and hours of operation on a daily basis.

(c) *Sugar Grinder & Hopper (E.U. ID No. 020)*: The permittee shall monitor and record the date and amount of sugar processed on a daily basis.

(d) *Storage Silos (E.U. ID Nos. 026, 027, & 028)*: The permittee shall monitor and record the date, silo loaded, and the amount transferred.

[Rule 62-213.440(1)(b), F.A.C]

C.12. Common Conditions: This emissions unit is also subject to **Specific Conditions H.1. through H.20.** contained in **Subsection H. Common Conditions.**

Subsection D. This section addresses the following emissions units.

E.U. ID No.	Sugar Refinery Brief Description
021	Central Dust Collection System No. 1 (Rotoclone No. 1)
022	Central Dust Collection System No. 2 (Rotoclone No. 2)
023	Cooler No. 1 (Wet Cyclone No. 1)
024	Cooler No. 2 (Wet Cyclone No. 2)
025	Fluidized Bed Dryer/Cooler
034	Bulk Load-out Operation
035	Transfer Bulk Load-out Operation

Emissions Units Details

Central Dust Collection System No. 1 (Rotoclone No. 1), designated Emissions Unit 021, used to control emissions from the Rotary Dryer, Bucket Elevator No. 10 (BE-10), and Belt Conveyor 11 (BC-11). The system is controlled by use of a skimmer followed by a wet rotoclone manufactured by AFF (Type W). The rotoclone exhausts through a stack 93' above grade.

Central Dust Collection System No. 2 (Rotoclone No. 2), designated Emissions Unit 022, used to control emissions from three (3) Rotex Screens, the Silo Scale, belt conveyors BC-16 and BC-19, the Packing Rotex Screen, the Packing Room Bins, the Bulk Curing Bins 1 through 6, Bucket Elevator 16 (BE-16) and the Sweco Shaker Screen. The system is controlled by use of wet rotoclone manufactured by AFF (Type W). The rotoclone exhausts through a stack 93' above grade.

Fluidized Bed Dryer, designated emissions unit 025 used as the primary sugar drying system with a permitted capacity of 36.25 TPH. The particulate matter emissions from the fluidized bed dryer are exhausted through a high efficiency baghouse manufactured by BETH GmbH, 23556 LÜB-beck (Type BETHPULS 6.60 x 7.5.10). The baghouse exhausts through a stack 80' above grade.

Cooler No. 1, designated Emissions Unit 023 used to cool drier sugar leaving the Rotary Dryer. The Cooler has a design capacity of 35.4 TPH. The Cooler exhausts to a wet cyclone vented at a height of 47' above grade.

Cooler No. 2, designated Emissions Unit 024 used to cool dried sugar leaving the Rotary Dryer. The Cooler has a design capacity of 35.4 TPH. The Cooler exhausts to a wet cyclone vented at a height of 35' above grade.

A 40 ft. x 80 ft. building to house a 1,700 cubic feet vacuum pan and associated process equipment. The associated process equipment includes a vacuum pan condenser, two centrifugals, syrup and molasses feed tanks, final liquor syrup storage tanks, one 5,000 gallon condensate collection tank, one 1,000 gallon centrifugal wash water tank, two 1,200 cubic feet seeder cutover tanks, motor control center room, MCC and centrifugal controller room, refined sugar conveying system, one 2,000 cubic feet receiver, and various pumps.

Bulk Load-out Operation, designated Emissions Unit 034 used to load sugar into either trucks or railcars. The operation includes a silo and a three-sided building. Emissions of fugitive particulate matter are controlled by use of the enclosure.

Transfer Bulk Load-out Station, Designated Emissions Unit 035 used to supply sugar to the packaging and transshipment facility. The operation includes four enclosed conveyors in series feeding refined sugar from the Bulk Load-out operation (E.U. ID 034) to an enclosed load-out building. Emissions of

fugitive particulate matter are controlled by use of the enclosure and high-pressure air curtains. Two additional storage and curing bins and new rotex screens have been added to the existing refinery building.

{Permitting note: The units are classified as synthetic minor sources under the PSD Program and considered as "Regulated Emissions Units" because they are subject to unit-specific federally enforceable emission limitations for particulate matter and visible emissions.}

Construction Restrictions

The following specific conditions apply to the emissions units listed above:
{Permitting notes: The following construction restrictions are "Not Federally Enforceable" and have been placed in the permit to identify the capacity of the unit to aid in determining future rule applicability. For the Refinery Operations, activities, which are completely enclosed and vented within the building, are not classified as air pollution sources.}

D.1. Design Specifications: The permittee shall not allow, cause, suffer or permit changes to the following Air Quality Control System (AQCS) specifications without prior authorization from the Permitting Authority:
[Rules 62-4.160(2), 62-210.200(228), and 62-210.300, F.A.C.]

(a) **Fabric Filter Control Devices**

E.U. ID No.	Design Flows[(1)]		AQCS Fabric Filter Specifications[(1)]		
	(ACFM)	(DSCFM)	Filtering Material	Filtering Area	A/C Ratio
025	70,620	N/A	PE 550	9,041	7.81

A/C Ratio – Air to Cloth Ratio (dscfm/sq. ft)
N/A – Not Applicable
PE 550 – Filter Quality per Manufacturer's Specifications

(1) - Not Federally Enforceable.
(2) – Potential Emissions include PM and PM10.

(b) **Cyclonic Control Devices**

E.U. ID No.	Design Flows[(1)]	AQCS Design Specifications[(1)]	
	(ACFM)	Water Injection Rate	Pressure Drop
021	19,000	7.5 gpm	9.0 in H_2O
022	19,000	7.5 gpm	9.0 in H_2O
023	14,100	7.5 gpm	8.0 in H_2O
024	14,100	7.5 gpm	8.0 in H_2O

ACFM – Actual Cubic Feet per Minute
gpm – gallons per minute, minimum value
in. H_2O – inches of water, minimum value
RD – Rotary Dryer FBD – Fluidized Bed Dryer

(1) - Not Federally Enforceable.
(2) – Potential Emissions Particulate Matter/PM10.

Essential Potential to Emit (PTE) Parameters

{Permitting notes: The operating restrictions which are identified as "Not Federally Enforceable" have been placed in the permit to identify the capacity of the unit for purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity, to establish emission limits, and to aid in determining future rule applicability.}

D.2. Permitted Capacities: Refined sugar production shall not exceed 1,500 tons per day and 390,000 tons per year. The permittee shall not allow, cause, suffer or permit the operation of a unit in excess of the following capacities without prior authorization from the Permitting Authority.

E.U.	Process Rates			
ID No.	RD - TPH	FBD - TPH	Total TPY*	Regulation/Permit
021	35.42	0.00	390,000	0990005-005-AC.
022	35.42	0.00	390,000	0990005-005-AC.
023	35.42	36.25	130,000	0990005-005-AC.
024	35.42	36.25	130,000	0990005-005-AC.
025	N/A	36.25	260,000	0990005-005-AC.
034	12.5	12.5	117,000	0990005-005-AC.
035	26.7	26.7	273,000	0990005-005-AC.

RD – Rotary Dryer FBD – Fluidized Bed Dryer
TPH – tons per hour TPY – tons per year
* Federally enforceable

[Rules 62-4.160(2), 62-210.200(228), and 62-210.300, F.A.C. and Construction Permit 0990005-002-AC, dated January 19, 2001 and Construction Permit 0990005-005-AC, dated January 19, 2001, Effective Date: March 18, 2004]

D.3. Isopropyl alcohol usage shall not exceed 78,040 pounds per year.
[Construction Permit 0990005-005-AC, dated January 19, 2001, Effective Date: March 18, 2004]

D.4. Refined sugar production from the fluidized bed sugar drying system shall not exceed 1,200 tons per day.
[Construction Permit 0990005-005-AC, dated January 19, 2001, Effective Date: March 18, 2004]

D.5. Refined sugar production from the rotary sugar drying system shall not exceed 1,200 tons per day and 130,000 tons per year.
[Construction Permit 0990005-005-AC, dated January 19, 2001, Effective Date: March 18, 2004]

D.6. Methods of Operation: The permittee shall not allow, cause, suffer, or permit any change in the method of operation without prior authorization from the Permitting Authority. The authorized methods of operation include the following:

(a) Rotary Dryer/Coolers: The permittee is authorized to use the Rotary Dryer and Cooler Nos. 1 and 2 for specialty sugars and in the event the fluidized bed dry/cooler is off line for repairs and vent the emissions units to the outside air through the AQCS. [Construction Permit 0990005-002-AC dated July 17, 1996]

(b) Central Dust Collection System No. 1: The permittee is authorized to operate the Rotary Dryer, Bucket Elevator No. 10 (BE-10), and Belt Conveyor 11 (BC-11) and vent the exhaust from each emissions unit to the outside air through the AQCS. [Not Federally Enforceable; Construction Permit 0990005-002-AC dated July 17, 1996]

(c) Central Dust Collection System No. 2: The permittee is authorized to operate the three (3) Rotex Screens, the Silo Scale, belt conveyors BC-16 and BC-19, the Packing Rotex Screen, the Packing Room Bins, the Bulk Curing Bins 1 through 6, Bucket Elevator 16 (BE-16) and the Sweco Shaker Screen and vent the exhaust from each emissions unit to the outside air through the AQCS. [Not Federally Enforceable; Construction Permit 0990005-002-AC dated July 17, 1996]

(d) Fluidized Bed Dryer/Cooler: The permittee is authorized to operate the Fluidized Bed Dryer/Cooler as the primary sugar drying process and vent the exhaust to the outside air through the AQCS. The permittee may operate the Fluidized Bed Dryer/Cooler at a maximum feed rate of 36.25 TPH. [Not Federally Enforceable; Construction Permit 0990005-002-AC dated July 17, 1996]

(e) Bulk Load-out Operation: The permittee is authorized to operate the existing Bulk Load-out operation continuously. Operations include transfer of sugar to trucks, railcars, or conveyors. All transfer operations shall be conducted within the three-sided enclosure. [Not Federally Enforceable; Construction Permit 0990005-002-AC dated July 17, 1996]

(f) Transfer Bulk Load-out Operation: The permittee is authorized to operate the Transfer Bulk Load-out operation continuously. Operations include the transfer of sugar to trucks. All transfer operations shall be conducted within the building enclosure and the air-curtains operating. [Not Federally Enforceable; Construction Permit 0990005-002-AC dated July 17, 1996]

Rules 62-4.160(2), 62-210.200(228), and 62-210.300, F.A.C.]

D.7. Hours of Operation: The permittee is authorized to operate the Fluidized Bed Dryer/Cooler, the Rotary Dryer, and Cooler Nos. 1 and 2, Bucket Elevator No. 10 (BE-10), belt conveyors BC-11, BC-16 and BC-19, bucket elevators BE-10 and BE-16, the three (3) Rotex Screens, the Silo Scale, the Packing Rotex Screen, the Packing Room Bins, the Bulk Curing Bins 1 through 6, and the Sweco Shaker Screen a maximum of 7,200 hours per year. The Bulk Load-out Operations (E.U. ID Nos. 034 and 035) are allowed to operate continuously.
[Construction Permit 0990005-002-AC dated July 17, 1996]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.8. Visible Emissions: The permittee shall not allow visible emissions greater than 5 percent opacity (6-minute average) from the Fluidized Bed Dryer/Cooler (E.U. ID No. 25), the Central Dust Collection System Nos. 1 and 2 (E.U. ID Nos. 021 and 022), Cooler Nos. 1 and 2 (E.U. ID Nos. 023 and 24), or the Bulk Load-out Operations (E.U. ID Nos. 34 and 35).
[Construction Permit 0990005-002-AC dated July 17, 1996]

D.9. Particulate Matter (PM & PM_{10}): Particulate matter emissions from the sugar refinery shall not exceed 36.80 tons/year and PM-10 emissions shall not exceed 13.39 tons/year. The permittee shall not allow particulate matter emissions from each unit greater than the following without prior authorization from the Permitting Authority:

E.U. ID No.	Allowable Emission (TPY)		
	PM	PM10	Regulation/Permit
021	6.179	2.48	0990005-002-AC.
022	1.748	0.69	0990005-002-AC.
023	17.13	9.48	0990005-002-AC.
024	17.13	9.48	0990005-002-AC
025	6.91	0.28	0990005-002-AC
034	2.86	1.35	0990005-002-AC
035	1.22	0.58	0990005-002-AC
Total	36.80	13.39	0990005-005-AC

[Rules 62-4.160(2), 62-210.200(228), and 62-210.300, F.A.C and Construction Permit 0990005-002-AC, dated January 19, 2001 and Construction Permit 0990005-005-AC, dated January 19, 2001, Effective Date: March 18, 2004]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.10. Visible Emissions: All visible emissions tests performed pursuant to the requirements of this permit shall comply with the following provisions:

(a) Test Method: The test method for visible emissions shall be EPA Method 9, incorporated in Rules 62-297.401(9), F.A.C. and the required minimum period of observation for a compliance test shall be thirty (30) minutes. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur.
[Rules 62-297.401and 62-297.310(4)(a)2., F.A.C., and Construction Permit 0990005-001-AC dated January 24, 1996]

(b) Test Procedures: Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[Permit 0990005-002-AC July 17, 1996]

D.11. Particulate Matter (PM & PM_{10}): All particulate matter tests performed pursuant to the requirements of this permit shall comply with the following:

(a) Test Method: The test methods for particulate matter shall be EPA Methods 1, 2, 3, 4, 5, 201 or 201A described in 40 CFR 60, Appendix A, Rules 62-297.401(1) through (5), (41) and (41)(a), F.A.C.
[Rule 62-297.401, F.A.C., and Construction Permit 0990005-002-AC July 17, 1996]

(b) Test Procedures: The test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[Rule 62-297.401, F.A.C.]

Compliance Demonstrations and Periodic Monitoring

D.12. Annual Compliance Demonstrations: The permittee shall have formal compliance tests conducted for visible emissions from each emissions point (E.U. ID Nos. 021, 022, 023, 024, 034, and 035) annually during each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, for the following pollutants.
[Rule 62-297.310(7), F.A.C]

D.13. Waiver of Compliance Test Requirements: For particulate matter (PM), the Permitting Authority has waived the particulate matter compliance test requirements and specified the alternative standard of 5% opacity (**Specific Condition D.8.**). If the Compliance Authority has reason to believe that either the design specifications of **Specific Condition D.1.** or the emissions rates are not being met, it shall require that compliance be demonstrated by the test methods specified in **Specific Condition D.11.**
[Rule 62-297.620(4), F.A.C. and Permit 0990005-002-AC dated July 17, 1996]

D.14. Operating Parameters: The permittee shall implement the following periodic monitoring requirements to ensure compliance with **Specific Conditions D.2., D.4. and D.5.** of this permit:

(a) *Central Dust Collection System No. 1 (E.U. ID No. 021)*: The permittee shall monitor and record the date, amount of sugar processed through the Rotary Dryer and hours of operation on a daily basis.

(b) *Fluidized Bed Dryer (E.U. ID No. 025)*: The permittee shall monitor and record the date, amount of sugar processed through the Fluidized Bed Dryer and hours of operation on a daily basis.

(c) *Cooler Nos. 1 and 2 (E.U. ID Nos. 023 & 024)*: The permittee shall monitor and record the date, amount of sugar processed through each cooler, and the hours of operation on a daily basis.

(d) *Bulk Load-out Operations (E.U. ID Nos. 034 and 035)*: The permittee shall monitor and record the date and amount of sugar transferred through each operation.

(e) The permittee shall keep records of the total daily-refined sugar production.

(f) The permittee shall keep records of the weekly use of isopropyl alcohol.

[Rule 62-213.440(1)(b), F.A.C and Construction Permit 0990005-005-AC, dated January 19, 2001, Effective Date: March 18, 2004]

D.15. Common Conditions: This emissions unit is also subject to **Specific Conditions H.1. through H.20.** contained in **Subsection H. Common Conditions.**

Subsection E. This section addresses the following emissions units for New Hope Power Partnership (AIRS ID No.: 0990332)

E.U. ID No.	Brief Description
004	Material Handling and Storage Operations (Cogeneration Facility)

Emissions Units Details

The materials handling and storage operations include authorization for truck and railcar unloading operations, storage piles, transfer operations, conveyors, screens, crushers, hoppers and silos. The materials authorized to be handled and stored include coal, biomass (bagasse and wood), ash (fly and bottom) and a mercury removal agent (Carbon). Unconfined particulate matter emissions from the operations are controlled through the use of Best Available Control Technology (BACT) and reasonable precautions as specified in the specific conditions.

The following specific conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

{Permitting note: The operating restrictions which are identified as "Not Federally Enforceable" have been placed in the permit to identify the capacity of the unit for purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity, to establish emission limits, and to aid in determining future rule applicability.}

E.1. Permitted Capacity. The permittee shall not allow, cause, suffer, or permit the operation of the unit in excess of the following capacities without prior authorization from the Permitting Authority. [Rules 62-4.160(2), 62-210.200(228), and 62-210.300, F.A.C.]

(a) Coal Handling: 74,000 tons per year (12-month rolling total) of bituminous coal. [Not Federally Enforceable]

(b) Biomass Handling: 2,200,000 tons per year (12-month rolling total) of biomass fuels (bagasse and wood). [Not Federally Enforceable]

(c) Fly Ash Handling: 74,000 tons per year (12-month rolling total) of removal agent (dry basis). [Not Federally Enforceable]

{Permitting note: Prior authorization includes the issuance of construction, reconstruction, or modification permits or a determination by the Permitting Authority that the action is not subject to 62-210.300(1), F.A.C.}

E.2. Methods of Operation: The permittee shall not allow, cause, suffer, or permit any change in the methods of operation without prior authorization from the Permitting Authority. The authorized methods of operation include the following:

(a) Coal Handling and Storage Operations[(1)]: The permittee is authorized to handle and store bituminous coal. The following activities are associated with these operations:

- Railcar & Truck Unloading
- Conveyor (Railcar to Coal Pile)

- Coal Storage Piles (Active & In-active)
- Reclaim Hopper
- Conveyor (Reclaim Hopper to Coal Crusher)
- Coal Crusher
- Conveyor (Coal Crusher to Conveyor)
- Conveyor (Conveyor to Boiler Silos)

(b) Biomass Handling and Storage Operations: The permittee is authorized to handle and store biomass fuels. The following activities are associated with these operations:

- Truck Unloading (Dumps #1 and #2, Unloading Bay)
- Chain Conveyors (#1 & #2)
- Unloading Conveyor
- Disk Screen
- Hogger
- Storage Conveyor
- Radial Stacker
- Biomass Storage Pile (Active & In-active)
- Underpile Chain Reclaimers (#1 and #2)
- Boiler Feed Conveyor
- Boiler Feed Conveyor Hopper
- Sugar Mill Bagasse Feed Conveyor
- Sugar Mill Bagasse Conveyor Hopper
- Chain Distribution Conveyors (#1 & #2)
- Boiler Meter Bins
- Recycle Conveyor
- Fixed Recycle Stacker

(c) Fly Ash Handling and Storage Operations: The permittee is authorized to handle and store fly ash. The following activities are associated with these operations:

- Boiler Bank Hoppers
- Air Preheater Hoppers
- Electrostatic Precipitator Hoppers
- Enclosed Drag Chain Conveyors
- Fly Ash Storage Silo (1,500 tons)
- Fly Ash Pug-Mill Conditioners
- Fly Ash Truck Loadout

(d) Mercury Removal Agent Handling and Storage Operations: The permittee is authorized to handle and store a mercury removal agent (carbon). The following activities are associated with these operations:

- Pneumatic Truck Unloading System
- Three Storage Silos
- Injection System

(e) Bottom Ash Handling and Storage Operations: The permittee is authorized to handle and store bottom ash. The following activities are associated with these operations:

- Submerged & Enclosed Drag Chain Conveyors
- Transfer Conveyor
- Collection Conveyor
- Three-Walled Storage Bunker
- Bottom Ash Truck Loadout

[Rules 62-4.160(2), 62-210.200(228), and 62-210.300, F.A.C.]

E.3. Hours of Operation: The permittee is authorized to operate the materials handling and storage operations continuously.
{Permitting note: The following notes address the Operating Restrictions: (1) Specific portions of the coal handling and storage operations, when constructed, will be subject to 40 CFR 60 Subpart Y and the applicant is required to comply with the General Provisions of 40 CFR Part 60, Subpart A. The equipment list is provided to identify activities subject to the visible emissions limitation of condition unregulated activities subject to the general opacity standard.}

Emission Limitations, Standards and Work Practices

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

E.4. Visible Emissions: The permittee shall not allow visible emissions from the materials handling and storage operations that exceed the following without prior authorization from the Permitting Authority:

(a) Coal & Biomass Handling and Storage Operations: An opacity greater than or equal to 5 percent, except when adding, moving or removing coal from the coal pile, which would be allowed at no more than 20 percent opacity.
[PSD-FL-196 and Construction Permit AC50-219413, as amended]

(b) Fly Ash Handling and Storage Operations: An opacity greater than or equal to 5 percent (6-minute average).
[PSD-FL-196 and Construction Permit AC50-219413, as amended]

(c) Mercury Control Agent Handling and Storage Operations: An opacity greater than or equal to 5 percent (6-minute average).
[PSD-FL-196 and Construction Permit AC50-219413, as amended]

E.5. Particulate Matter (PM & PM_{10}): The permittee shall not allow particulate matter emissions to exceed the following without prior authorization from the Permitting Authority.

(a) Fly Ash Storage Silo: The permittee shall not allow, by design, emissions greater than 0.01 grains per actual cubic foot (gr/acf) outlet dust loading from the silo baghouse.
[PSD-FL-196 and Construction Permit AC50-219413, as amended]

(b) Mercury Control Agent Silos: The permittee shall not allow, by design, emissions greater than 0.01 grains per actual cubic foot (gr/acf) outlet dust loading from the silo baghouses.
[PSD-FL-196 and Construction Permit AC50-219413, as amended]

[Rules 62-4.160(2), 62-210.200(228), and 62-210.300, F.A.C.]

E.6. Fugitive Dust Controls: The permittee shall implement the following controls to minimize particulate matter emissions:

(a) All conveyors and conveyor transfer points shall be enclosed to preclude PM emissions (except those directly associated with the stacker/reclaimers, for which enclosure is operationally infeasible).

(b) Inactive coal storage piles shall be shaped, compacted, and oriented to minimize wind erosion. Sod, wetting agents, synthetic or other appropriate materials shall be used to cover those parts of the inactive coal pile that are prone to wind or water erosion.

(c) Water sprays or chemical wetting agents and stabilizers shall be applied to storage piles, handling equipment, unenclosed transfer points, etc. during dry periods and as necessary to all facilities to maintain an opacity in compliance with condition **E.4.** of this permit.

(d) 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 it being discharged into the disposal bin.

(e) 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.
[PSD-FL-196 and Construction Permit AC50-219413, as amended]

E.7. Fuel Management Plan: The permittee shall comply with the conditions of the April 1, 1994 Fuel Management Plan contained in Appendix FMP-001.
[PSD-FL-196 and Construction Permit AC50-219413, as amended]

E.8. Ash Management Plan: The permittee shall comply with the conditions of the April 1, 1994 Ash Management Plan contained in Appendix AMP-001.
[PSD-FL-196 and Construction Permit AC50-219413, as amended]

E.9. Operation and Maintenance Plans: Within ninety (90) days of the effective date of this permit, the permittee shall submit to the Permitting Authority operation and maintenance plans that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible. The O/M Plans shall be incorporated into this permit as the following appendices:

(a) Appendix OMP-001, Fly Ash Silo Baghouse; and

(b) Appendix OMP-002, Mercury Control Agent Storage Silo Baghouses.

[PSD-FL-196 and Construction Permit AC50-219413, as amended] {Permitting notes: The controls identified in condition **E.6.** are specified within the construction permits and federally enforceable. Those identified in condition **E.7.** are in addition to controls specified in the construction permits and were identified within the initial Title V application.}

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

E.10. Visible Emissions: All visible emissions tests performed pursuant to the requirements of this permit shall comply with the following provisions:

(a) Test Method: The test method for visible emissions shall be EPA Method 9, incorporated in Rule 62-297.401(9), F.A.C. and the required minimum period of observation for an annual compliance test shall be thirty (30) minutes. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur.
[Rules 62-296.410(3)(a) and 62-297.310(4)(a)2., F.A.C.]

(b) Test Procedures: Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[PSD-FL-196 and Construction Permit AC50-219413, as amended]

E.11. Particulate Matter (PM & PM_{10}): All particulate matter tests performed pursuant to the requirements of this permit shall comply with the following:

(a) Test Method: The test methods for particulate matter shall be EPA Methods 1, 2, 3, 4, 5, 201 and 201A described in 40 CFR 60, Appendix A, Rules 62-297.401(1) through (5), (41) and (41)(a), F.A.C.
[Rule 62-297.401, F.A.C.]

(b) Test Procedures: The test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[Rule 62-297.401, F.A.C.]

Compliance Demonstrations and Periodic Monitoring

E.12. Compliance Demonstrations: The permittee shall conduct formal compliance tests for visible emissions annually each federal fiscal year (October 1 – September 30) and prior to renewal for particulate matter, unless otherwise specified by rule, order, or permit.
[Rule 62-297.310(7)(a)3 and 4, F.A.C, PSD-FL-196, and AC50-219413, as amended]

E.13. Operating Parameters: The permittee shall implement the following periodic monitoring requirements to ensure compliance with the conditions **E.1.** and **E.2.** of this permit:

(a) Coal Handling: The permittee shall maintain records on each coal shipment including date and amount.

(b) Biomass Handling: The permittee shall maintain records on each biomass shipment including date and amount.

(c) Fly Ash Handling: The permittee shall maintain records on each fly ash shipment including date and amount.

[Rule 62-213.440(1)(b), F.A.C]

New Source Performance Standards (NSPS) – 40 CFR 60

{Permitting note: The proposed coal handling and storage operations are subject to the requirements of 40 CFR 60 Subpart A-General Provisions and Subpart Y-Standards of Performance for Coal Preparation Plants. The NSPS include notifications, emission limitations, and testing requirements.}

E.14. 40 CFR 60 Subpart A, General Provisions: The permittee shall comply with the applicable requirements of 40 CFR 60 Subpart A contained in Appendix NSPS-A. Specifically:

(a) 40 CFR 60.7, Notification and Recordkeeping,
(b) 40 CFR 60.8, Performance Tests,
(c) 40 CFR 60.11, Compliance with Standards and Maintenance Requirements,
(d) 40 CFR 60.12 Circumvention,
(e) 40 CFR 60.14, Modification, and
(f) 40 CFR 60.19 General Notification and Reporting Requirements

[40 CFR 60.1 and Rule 62-204.800(7)(a), F.A.C.]

E.15. 40 CFR 60 Subpart Y, Standards of Performance for Coal Preparation Plants: The permittee shall comply with the applicable requirements of 40 CFR 60 Subpart Y contained in Appendix NSPS-Y. Specifically:

(a) 40 CFR 60.252(c), Standards for Particulate Matter, and
(b) 40 CFR 60.254(a)(2), Test Methods and Procedures.

[40 CFR 60.250(a) and (b), and Rule 62-204.800(7)(b), F.A.C.]

Common Conditions

E.16. Common Conditions: This emissions unit is also subject to **Specific Conditions H.1.** through **H.23.** contained in **Subsection H. Common Conditions.**

Subsection F. This section addresses the following emissions units for New Hope Power Partnership (AIRS ID No.: 0990332)

E.U. ID No.	Brief Description
001	Cogeneration Boiler No. A
002	Cogeneration Boiler No. B
003	Cogeneration Boiler No. C
005	Cogeneration Facility NSPS Storage Tank

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).

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 (400 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.

REGULATORY CLASSIFICATION

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. The boilers have been reviewed under the PSD Program for sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), nitrogen oxides (NOx), beryllium, and total fluorides. The boilers are synthetically limited (federally enforceable) for particulate matter (TSP & PM10), volatile organic compounds (VOC), carbon monoxide (CO), lead, and mercury. The synthetic emission limits for VOC and NOx, are more stringent than the Reasonably Available Control Technology (RACT) requirements of Rule 62-296.570, F.A.C.

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 boilers are classified as new facilities under the New Source Performance Standards (40 CFR 60 Subpart Da), and the fuel storage tanks are classified under Subpart Kb. Rule 62-296.405(2), F.A.C., Fossil Fuel Fire Steam Generators with more than 250 million Btu per Hour of Heat Input, and Rule 62-296.410, F.A.C., Carbonaceous Fuel Burners. Emission limitations for the boilers have been established through various federally enforceable permit conditions. The boilers are classified as "Qualifying Cogeneration Facilities" under 40 CFR Part 72, and exempt from the requirement to obtain an Acid Rain Permit.

CONSTRUCTION DETAILS

F.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.
[Construction Permit 0990332-014-AC/PSD-Fl-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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.}
[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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.
[Construction Permit 0990332-014-AC/PSD-Fl-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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.
[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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. Four burners are installed with one in each corner the boiler. The maximum heat input rate from all four burners is 400 MMBtu per hour.

- Mechanical dust collectors consisting of four, large diameter, multi-tube modules with airfoil vanes or equivalent equipment. The mechanical dust collectors shall be installed and maintained as pre-control devices prior to each electrostatic precipitator and designed for a removal efficiency of at least 85% of the particulate matter greater than 10 microns in size (assuming a specific gravity of 2.00).
- An electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter.
- A selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of NOx.
- A carbon injection system (or equivalent) for potential control of mercury emissions.

[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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 (O2), and sulfur dioxide (SO2) 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.
[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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.

[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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.

[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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.

[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

Operational Restrictions

F.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, 400 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 $11.5 \times 10^{+6}$ MMBtu 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.
[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

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 Methods 3050/6010 (EPA Method SW-846) 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.
[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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.
[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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.
[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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 SO2 emissions and the 12-month rolling total SO2 emissions shall be determined and kept in a log.
[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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.
[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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.
[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

Emissions Limiting Standards

F.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 (SO2) [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/PM10) [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 SO2 standards shall be determined by data collected from the required SO2 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 SO2 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 SO2 emissions with the firing of low sulfur fuels. For reporting purposes, sulfuric acid mist emissions shall be estimated as 6% of the total measured SO2 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 PM10 emissions, it shall be assumed that all particulate matter emitted is PM10.

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 **Specific Condition F.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.}

[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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.

[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

Startup, Shutdown, and Malfunction

F.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 the operating temperature recommended by the ESP manufacturer is maintained (approximately 340° F to 350 ° F), it shall be placed on line and the boiler shall comply with the opacity standard specified in **Specific Condition F.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 than twenty 6-minute block averages of opacity monitoring data shall be excluded in a 24-hour period due to documented malfunctions.

2) Hourly CO and NOx emission rate values collected during startup, shutdown, or documented malfunction may be excluded from the 30-day and/or 12-month compliance averages. No more than six hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a cold startup. No more than three hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a warm startup. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a malfunction. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a shutdown. For each cogeneration boiler, no more than 183 hourly emission rate values shall be excluded during any calendar quarter.

3) All valid hourly SO2 emission rate values shall be included in all of the compliance averages. [40 CFR 60.46a and 60.49a]

4) To "document" a malfunction, the operator shall notify the Compliance Authority within one working day of the malfunction by phone, facsimile, or electronic mail. The notification shall include the date and time of malfunction, a description of the malfunction and probable cause, steps to taken to minimize emissions, and actions taken to correct the problem. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

d. *Reporting*: In conjunction with the annual operating report, the permittee shall identify the number of startups, the number of shutdowns, and the number of malfunctions that occurred during the year for each boiler. For each boiler's CO and NOx monitors, the report shall identify the annual hours of emission data excluded from the compliance determination due to each type of incident (startups; shutdowns; and documented malfunctions).

[Rule 62-210.700, F.A.C.; Rule 62-4.070(3), F.A.C.; 40 CFR 60.8; and 40 CFR 60.46a and Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

Compliance Methods and Reporting

F.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 within 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).

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 O2
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 SO2.

[Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A and Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.21. Continuous Monitor Requirements: The permittee shall demonstrate compliance with the emissions standards for CO, NOx, opacity, and SO2 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.
[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.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.
[Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.23 Wood-Waste And Ash Inspection And Testing Plan: The permittee shall monitor and inspect the biomass fuels in accordance with Appendix FMTP-001, Wood-Waste And Ash Inspection And Testing Plan to ensure compliance with **Specific Condition F.6.** of this permit.
[Rule 62-213.440(1)(b), F.A.C. and Construction Permit 0990005-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

New Source Performance Standards (NSPS) - 40 CFR 60

{Permitting notes: The cogeneration facility boilers are subject to the requirements of 40 CFR 60 Subpart Ea Standards of Performance for Municipal Waste Combustors for Which Construction is Commenced After December 20, 1989 and on or Before September 20, 1994, and 40 CFR 60 Subpart Da- Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978. The NSPS include notifications, exemptions, emission limitations, monitoring, and testing requirements.}

F.24. 40 CFR 60 Subpart A, General Provisions: The permittee shall comply with the applicable requirements of 40 CFR 60 Subpart A contained in Appendix NSPS-A of this permit. Specifically:

(a) 40 CFR 60.5, Determination of Construction or Modification,
(b) 40 CFR 60.6, Review of Plans,
(c) 40 CFR 60.7, Notification and Recordkeeping,
(d) 40 CFR 60.8, Performance Tests,
(e) 40 CFR 60.11, Compliance with Standards and Maintenance Requirements,
(f) 40 CFR 60.12 Circumvention,
(g) 40 CFR 60.13, Monitoring Requirements,
(h) 40 CFR 60.14, Modification,
(i) 40 CFR 60.15, Reconstruction,
(j) 40 CFR 60.17, Incorporation by Reference, and
(k) 40 CFR 60.19, General Notification and Reporting Requirements

[40 CFR 60.1, and Rule 62-204.800(7)(a), F.A.C. and Construction Permit 0990005-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.25. 40 CFR 60 Subpart Da- Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978: The permittee shall comply with the applicable requirements of 40 CFR 60 Subpart Da contained in Appendix NSPS-Da. Specifically:

(a) 40 CFR 60.41a, Definitions,
(b) 40 CFR 60.42a(a), (a)(1), (a)(2), (a)(3) and (b), Standard for Particulate Matter,

(c) 40 CFR 60.43a(a), (b)(2), (d)(2), (g), (h)(1) and (h)(2), Standard for Sulfur Dioxide,

(d) 40 CFR 60.44a(a), (a)(1), (a)(2), and (c), Standard for Nitrogen Oxides,

(e) 40 CFR 60.46a(a), (b), (c), (e), (f), (g) and (h), Compliance Provisions,

(f) 40 CFR 60.47a(a), (b), (b)(2), (c), (d), (e), (f), (g), (h), (h)(1), (h)(2), (h)(3), (h)(4), (i), (i)(1), (i)(2), (i)(5), (j), (j)(1), (j)(2), (j)(3), and (j)(4), Emission Monitoring,

(g) 40 CFR 60.48a(a), (b), (b)(1), (b)(2), (b)(3), (c)(3), (c)(4), (c)(5), (d), (d)(1), (d)(2), (e), (e)(1), and (e)(2), Compliance Determination Procedures and Methods, and

(h) 40 CFR 60.49a(a), (b), (b)(1), (b)(2), (b)(4), (b)(5), (b)(6), (b)(7), (b)(8), (b)(9), (c), (c)(1), (c)(2), (c)(3), (c)(4), (c)(5), (f), (g), (g)(1), (g)(2), (g)(3), (g)(4), (h), and (i), Reporting Requirements.

[40 CFR 60.40a(a)(1) and (a)(2), and Rule 62-204.800(7)(b), F.A.C. and Construction Permit 0990005-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

F.26. 40 CFR 60 Subpart Ea - Standards of Performance for Municipal Waste Combustors for Which Construction is Commenced After December 20, 1989 and on or Before September 20, 1994: The permittee shall comply with the applicable requirements of 40 CFR 60 Subpart Ea contained in Appendix NSPS-Ea. Specifically the following sections related to applicability:

(a) 40 CFR 60.50a(a), (d), (e), (g), and (h), Applicability and Delegation of Authority, and

(b) 40 CFR 60.51a, Definitions

[Construction Permit 0990005-014-AC/PSD-FL-196M, dated January 31, 2002, Effective Date: March 18, 2004]

Common Conditions

F.27. Common Conditions: This emissions unit is also subject to **Specific Conditions H.1. through H.20.** contained in Subsection **H. Common Conditions.**

Subsection G. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
048	Paint Booth

This Emissions Unit consists of a paint spray booth that will be used to paint farm equipment. The paint spray booth is manufactured by AFC, Inc. The model number is TSD6036.

{Permitting note: The painting operations conducted on agricultural equipment in the spray booth are subject to reasonably achievable control technology (RACT) requirements of Rule 62-296.513, Florida Administrative Code (F.A.C.)}

The following specific conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

G.1. Permitted Capacity. The maximum throughput rate of paint and thinner is 2,475 gallons per year. [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and Construction Permit 0990005-010-AC, dated August 22, 2001, Effective Date: March 18, 2004]

G.2. Methods of Operation. Paint will be applied by one of two methods, compressed air spray gun or an airless paint sprayer. The compressed air spray gun will use house air within a pressure range of 60 to 80 pounds per square inch (psi). The airless paint sprayer will be a Titan airless paint sprayer, Model Epic 1100HPX. It will operate at a pressure of approximately 3,200 psi. There are two exhaust stacks for the paint spray booth. Both are 25.7 feet tall with a 4-foot diameter and have a flowrate of 45,500 acfm.
[Rule 62-213.410, F.A.C.; and Construction Permit 0990005-010-AC, dated August 22, 2001, Effective Date: March 18, 2004]

G.3. Hours of Operation. This emissions unit is allowed to operate continuously, 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.; and Construction Permit 0990005-010-AC, dated August 22, 2001, Effective Date: March 18, 2004]

Emission Limitations and Standards

G.4. The permittee may adjust the amounts and types of coatings used as necessary to comply with the conditions of this permit.
[Construction Permit 0990005-013-AC, dated November 13,2003, Effective Date: March 18, 2004]

G.5. For painting operations conducted on agricultural equipment:

a.) The permittee shall not cause, allow, or permit the discharge into the atmosphere of any volatile organic compounds (VOC) in excess of 3.5 pounds per gallon of coating (0.42 kilograms per liter), excluding water, delivered to a coating applicator in a coating application system that is air dried or forced warm dried at temperatures up to 194 degrees Fahrenheit (90 degrees Celsius).

b.) All VOC emissions from solvent washings shall be considered in the emission limitations in Specific Condition 5., unless the solvent is directed into containers that prevent evaporation into the atmosphere.
[Rule 62-296.513(2)(b), F.A.C.]

c.) The emissions limit in Specific Condition 5. shall be achieved by the application of low solvent coating technology.
[Rule 62-296.513(3)(a), F.A.C.]

d.) The test method for VOC emissions using low solvent coating technology shall be EPA Method 24 incorporated and adopted by reference in Chapter 62-297, F.A.C.
[Rule 62-296.513(4)(a), F.A.C.]

e.) Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[Rule 62-296.513(4), F.A.C.]

f.) The permittee shall maintain daily records of operations for the most recent two-year period. The records shall be made available to the include, but not limited to, the following: Department upon request. The records shall

1. The rule number applicable to the operation for which the records are being maintained.
2. The application method and substrate type (metal, plastic, paper, etc.)
3. The amount and type of adhesive, coatings (including catalysts and reducer for multicomponent coatings), solvent, and/or graphic arts material used at each point of application, including exempt compounds.
4. The VOC content as applied in each adhesive coating, solvent and/or graphic arts material.
5. The date for each application of adhesive coating, solvent, and/or graphic arts material.
6. The amount of surface preparation, clean-up, wash-up of solvent (including exempt compounds) used and the VOC content of each.
7. Oven temperature (where applicable)
[Rule 62-296.500(2)(b)1., F.A.C.]

g) The VOC content shall be calculated using a percent solids basis (less water and exempt solvents) for adhesives, coating, and inks, using EPA Reference Method 24.
[Rule 62-296.500(2)(b)2., F.A.C.]

[Construction Permit 0990005-013-AC, dated November 13, 2003, Effective Date: March 18, 2004]

G.6.. Emissions of volatile organic compounds (VOCs) from the spray booth are limited to 3.9 tons per year.
[Construction Permit 0990005-010-AC, dated August 22, 2001, Effective Date: March 18, 2004]

G.7. Emissions of particulate matter (PM) are estimated to be less than 0.23 tons per year.
[Construction Permit 0990005-010-AC, dated August 22, 2001, Effective Date: March 18, 2004]

G.8. The exhaust stacks for the paint spray booth will be equipped with glass fiber paint arrestor pads.
Construction Permit 0990005-010-AC, dated August 22, 2001, Effective Date: March 18, 2004]

G.9.. Visible emissions from the paint spray booth shall not exceed 20% opacity.
[Rule 62-296.320, F.A.C.]
[Construction Permit 0990005-010-AC, dated August 22, 2001, Effective Date: March 18, 2004]

G.10. The permittee shall not discharge air pollutants, which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C. and Construction Permit 0990005-010-AC, dated August 22, 2001, Effective Date: March 18, 2004]

G.11. The permittee shall take all reasonable precautions to prevent emissions of unconfined particulate matter. Reasonable precautions may include, but shall not be limited to, (a) removal of particulate matter from roads and other paved areas under the control of the permittee, and from buildings or work areas to prevent particulate from becoming airborne, (b) landscaping or planting of vegetation, (c) use of hoods, fans, filter, and similar equipment to contain, capture and/or vent particulate matter, and (d) confining abrasive blasting and sanding where possible.
[Rule 62-296.320(4)(c), F.A.C. and Construction Permit 0990005-010-AC, dated August 22, 2001, Effective Date: March 18, 2004]

G.12. All equipment, pipes, hoses, lids, fittings, etc., shall be operated/maintained in such a manner as to minimize leaks, fugitive emissions, and spills of solvent materials.
[Rule 62-296.320, F.A.C. and Construction Permit 0990005-010-AC, dated August 22, 2001, Effective Date: March 18, 2004]

Recordkeeping and Reporting Requirements

G.13. The permittee shall record and maintain records of the following:

a) the number of hours that the spray booth is in use (actual);
b) the dates of operation;
c) the amounts and types of coating used;

The permittee shall calculate the VOC emitted on a monthly basis by assuming that all VOC in the coatings and cleanup solvents are evaporated. The mass fraction of VOC from each coating material (and cleanup solvents) shall be determined from the Material Safety Data Sheets (MSDS) supplied from the vendors. The permittee shall maintain a file of MSDS for each raw material which indicates the composition of the volatile organic compounds. Raw materials include, but are not limited to, powder coatings, solvent coatings, thinners, and cleaners. The file must be maintained on site and made available for inspection upon request. The permittee shall have until the 15th day of the following month to complete these records.
[Rules 62-210.370, and 62-296.500(2)(c), F.A.C. and Construction Permit 0990005-013-AC, dated November 13, 2003, Effective Date: March 18, 2004]

G.14. The amounts and types of coatings used and the calculated VOC emissions shall be included in the annual report.
[Rules 62-210.370 and 62-296.500(2)(c), F.A.C. and Construction Permit 0990005-013-AC, dated November 13, 2003, Effective Date: March 18, 2004]

G.15. Copies of all reports, tests, notifications or other submittals required by this permit shall be submitted to both the Department of Environmental Protection, South District and the Palm Beach County Public Health Unit.
[Rule 62-210.370, F.A.C.]

Reasonable Assurances

G.16. Although there are not minimum ventilation airflow rates (this is a fugitive VOC emitting source) required by this permit to satisfy the Department of Environmental Protection, other regulations (i.e. OSHA) may require such flow rates. It is the permittee's responsibility to comply with all applicable regulations. Future regulations my impact this facility at some future date. The permittee shall comply with any applicable future regulations when they become effective.
[Rule 62-210.300, F.A.C.]

G.17. Common Conditions: This emissions unit is also subject to **Specific Conditions H.1. through H.20.** contained in **Subsection H. Common Conditions.**

Subsection H. Common Conditions.

This section addresses the common conditions for the following emissions units as noted within each emissions units section.

E.U. ID No.	Status	Brief Description
003	Regulated	Mill Boiler No. 4
004	Regulated	Mill Boiler No. 5
005	Regulated	Mill Boiler No. 6
009	Regulated	Mill Boiler No. 10
010	Regulated	Mill Boiler No. 11
011	Regulated	Mill Boiler No. 12
012	Regulated	Mill Boiler No. 14
013	Regulated	Mill Boiler No. 15
014	Regulated	Mill Boiler No. 16
015	Regulated	Sugar Mill NSPS Storage Tank
016	Regulated	Sugar Mill NSPS Storage Tank
017	Regulated	Sugar Mill NSPS Storage Tank
018	Regulated	Central Vacuum System for the Trans-Shipment Facility
019	Regulated	Packaging Lines
020	Regulated	Sugar Grinder and Hopper
021	Regulated	Central Dust Collection System No. 1 (Wet Rotoclone #1)
022	Regulated	Central Dust Collection System No. 2 (Wet Rotoclone #2)
023	Regulated	Cooler No. 1 (Cyclone No. 1)
024	Regulated	Cooler No. 2 (Cyclone No. 2)
025	Regulated	Fluidized Bed Dryer/Cooler
026	Regulated	Sugar Silo (S1101)
027	Regulated	Sugar Silo (S1102)
028	Regulated	Sugar Silo (S1103)
029	Regulated	Materials Handling and Storage Operations (Cogeneration Facility)
030	Regulated	Cogeneration Boiler No. 1

E.U. ID No.	Status	Brief Description
031	Regulated	Cogeneration Boiler No. 2
032	Regulated	Cogeneration Boiler No. 3
033	Unregulated	Cogeneration Facility NSPS Storage Tank
034	Regulated	Bulk Load-out Operation
034	Regulated	Transfer Bulk Load-out Operation

H.1. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard.
[Rule 62-297.310(1), F.A.C.]

H.2. Operating Rate During Testing: Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operating at permitted capacity as defined below. 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 62-297.301(2), F.A.C.]

H.3. Permitted Capacity: Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit.
[Rule 62-297.310(2)(b), F.A.C.]

H.4. Calculation of Emission Rate: 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.]

H.5. 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.
[Rule 62-297.310(4)(a)1, F.A.C.]

H.6. Opacity Compliance Tests: When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

(a) For batch, cyclical processes, or other operations, which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

(b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

[Rule 62-297.310(4)(a)2, F.A.C.]

H.7. Minimum Sample Volume: Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
[Rule 62-297.310(4)(b), F.A.C.]

H.8. Required Flow Rate Range: For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
[Rule 62-297.310(4)(c), F.A.C.]

H.9. Allowed Modification to EPA Method 5: When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4)(e), F.A.C.]

H.10. 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.
[Rule 62-297.310(5)(a), F.A.C.]

H.11. Calibration of Sampling Equipment: Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.
[Rule 62-297.310(4)(d), F.A.C.]

Table 297.310-1 Calibration Schedule			
Item	**Minimum Calibration Frequency**	**Reference Instrument**	**Tolerance**
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. Thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 &2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded Max. deviation between readings	Micrometer	+/-0.001" mean of at least three readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually 3. Check after each test series	Spirometer or calibrated wet test or dry gas test meter Comparison check	2% 5%

H.12. 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)(b), F.A.C.]

H.13. 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 a

special compliance test. The special compliance test shall be conducted within 15 days of operation of the E.U. outside the design criteria of the AQCS (air quality control system). The special compliance test shall be conducted to document compliance with the emission limitations and to establish a normal range of operation.
[Rule 62-297.310(7)(b), F.A.C.]

H.14. Waiver of Compliance Test Requirements: If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7)(c), F.A.C.]

H.15. Compliance Test Notification: The permittee shall notify the Compliance Authority fifteen (15) days prior to Emission Unit (E.U.) testing.
[Rule 62-297.310(7)(a)(9), F.A.C.]

H.16. Compliance Test Submittal: Copies of the test report(s) shall be submitted to the Permitting Authority and the Compliance Authority within forty-five (45) days of completion of testing.
[Rule 62-297.310(8)(b), F.A.C.]

H.17. Test Reports: The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
[Rule 62-297.310(8)(c), F.A.C.]

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time, and duration of each sampling run.

9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer, and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing, and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

H.18. Recordkeeping: The permittee shall ensure that all records of monitoring information shall specify the date, place, and time of sampling or measurement and the operating conditions at the time of sampling or measurement, the date(s) analyses were performed, the company or entity that performed the analyses, the analytical techniques or methods used, and the results of such analyses.
[Rule 62-213.440(1)(b)2.a., F.A.C.]

H.19. Record Retention: The permittee shall retain records of all monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information shall include all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.
[Rule 62-213.440(1)(b)2.b., F.A.C.]

H.20. Alternate Sampling Procedure: The owner or operator of any emissions unit subject to the provisions of this chapter may request in writing a determination by the Secretary or his/her designee that any requirement of this chapter (except for any continuous monitoring requirements) relating to emissions test procedures, methodology, equipment, or test facilities shall not apply to such emissions unit and shall request approval of an alternate procedures or requirements.

The request shall set forth the following information, at a minimum:

(a) Specific emissions unit and permit number, if any, for which exception is requested.

(b) The specific provision(s) of this chapter from which an exception is sought.

(c) The basis for the exception, including but not limited to any hardship which would result from compliance with the provisions of this chapter.

(d) The alternate procedure(s) or requirement(s) for which approval is sought and a demonstration that such alternate procedure(s) or requirement(s) shall be adequate to demonstrate compliance with applicable emission limiting standards contained in the rules of the Department or any permit issued pursuant to those rules.

The Secretary or his/her designee shall specify by order each alternate procedure or requirement approved for an individual emissions unit source in accordance with this section or shall issue an order denying the request for such approval. The Department's order shall be final agency action, reviewable in accordance with Section 120.57, Florida Statutes.
[Rule 62-297.620, F.A.C.]

H.21 Modification: Upon modification, each emissions unit shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere in accordance with 40 CFR 60.14 contained in Appendix NSPS-A.
[40 CFR 60.14 and Rule 62-204.800(7)(d), F.A.C.]

H.22 Emission Rate Increases: When a determination of an emission rate increase is required and is based on results from manual emission tests or continuous monitoring systems, the procedures specified in 40 CFR 60 Appendix C shall be used to determine whether an increase in emission rate has occurred in accordance with 40 CFR 60.14 contained in Appendix NSPS-A. [40 CFR 60.14 and Rule 62-204.800(7)(d), F.A.C.]

H.23 Reconstruction: Upon reconstruction, each emissions unit shall become an affected facility, irrespective of any change in emission rate in accordance with 40 CFR 60.15 contained in Appendix NSPS-A. [40 CFR 60.15 and Rule 62-204.800(7)(d), F.A.C.

A. PERMIT CONDITIONS

Palm Beach County Restrictions on Ash Management

A detailed ash management plan must be submitted by the petitioner and approved by the Palm Beach County Health Department. The plan must detail contingency plans, testing, and monitoring of the ash, ash handling and disposal methods, planned spreading locations and identification of environmental impacts and measures for mitigating those impacts (Petition 92-14, Condition F5).

All fly ash and bottom ash from the facility which are produced during any period in which fossil fuels are used, and thereafter for a reasonable time, shall be segregated and managed as set forth in the ash management plan (92-14, F4).

FDEP Industrial Wastewater Permit Restrictions on Ash Management

None evident.

A Management of Surface Waters permit draft is not yet available for review. We believe that the agency is satisfied that county requirements on fuel usage and ash management are sufficient.

B. BAGASSE AND WOOD

Ash Quantities

The maximum quantities of bottom and fly ash that could be generated during normal operation are provided below:

Fuel	Bottom Ash T/yr	Fly Ash T/vr
Bagasse	1,800	5,500
Wood	3,600	10,800
TOTALS	5,400	16,300

The amount of ash generated by firing bagasse has been based upon operating on bagasse for 150 days per year. The amount of ash generated by firing wood has been based upon operating on wood for 215 days per year. Due to the occurrence of planned and unplanned shutdown during the year, the quantities noted above are conservatively high.

System Description

Bottom Ash

Bottom ash will be discharged continuously from each boiler into three water—submerged drag chain conveyors. Each conveyor will consist of a wet upper compartment and a dry lower compartment. The upper compartment will be a water-tight steel trough, designed to contain the water required for quenching and cooling the bottom ash to 140ºF, and sized to accommodate and store up to 2 hours of bottom ash generated from the wood or bagasse.

The submerged chain conveyor will be designed for a removal rate of 8 tph. An integrated water supply and recirculation system will be used. Over flow water from the submerged dry chain conveyor trough, hopper seal trough, and dewatered ash storage pile will be piped back to a recirculation sump equipped with an overflow weir and a return sump pump. Make-up water will be added to the recirculation sump to replace water lost in the dewatered ash and through evaporation.

The dewatered ash from the dewatering inclined ramp of the chain conveyor will be discharged into a 8 tph transfer conveyor which will transfer the dewatered ash into a 25 tph collecting conveyor, which in turn will unload the ash into a three-sided bunker, sized to accommodate about a 7-day ash capacity. A front-end loader will be used to reclaim and load the stored ash into trucks.

Fly Ash

Fly ash will consist of ash collected in air heater hoppers, dust collector hoppers, and from ESP hoppers. The system will encompass the removal and conveying of the fly ash from the hoppers to a storage silo,

using a dry ash vacuum pneumatic conveying system.

Two main transport pipeline will be used, each serving all hoppers. Each pipeline will be designed for conveying ash to separator/filter units mounted on the top of the storage silo. Vacuum blowers of 100-percent capacity, each serving one pipeline, and a system of cross-ties between the pipelines will be provided. An additional 100-percent vacuum blower will serve as a common back-up. The system conveying capacity will be sufficient to remove 24 hours of ash generation in 6 to 8 hours. System piping will be abrasion/corrosion resistant-type, hardened, cast alloy metal pipes and elbows. Elbows will be constructed with replacement wear-back sections.

The ash storage silo will be sized to accommodate 1,500 tons (about 7 days) of fly ash. The silo will be a conical bottom cylinder type carbon steel structure. Two twin shaft pug-mill conditioner unloaders rated at 200 tph each will be provided for discharging the ash into trucks for disposal.

Ash Removal

Fly ash will be loaded from the fly ash silo directly into trucks. Bottom ash falls from the boiler's grate into a water filled collection tank. From there the ash is conveyed by submerged drag chain onto a collection conveyor for transport to the three-walled bunker with a roof. At this point the ash is extremely wet. Under normal operating procedures, the ash will be removed from the bunker in a wetted condition. If it is determined that the bottom ash in storage has become dry, it will be sprayed with water.

Bottom ash will be removed from the storage bunkers by a front-end loader and also loaded into trucks. Loading of the trucks will be accomplished during daylight hours, with the fly ash silo and bottom ash bunkers providing the necessary overnight storage. The trucks will be covered and trucked to the designated staging area.

Ash Spreading

At the staging area the ash will be commingled and transferred to the spreaders. The spreaders will be drawn around the designated fields and the ash will be evenly distributed across the field. It is anticipated that the ash will be spread at a rate of approximately 2 tons per acre. The spreading of ash will take place over selected portions of Okeelanta's 90,000 acres of farmland. The ash will be spread on fallow fields, therefore, the specific location and schedule of the spreading will depend on the crop rotation plan developed each year by the Okeelanta farming operation and thus is not available at this time. If a fugitive dust problem exists after the ash has been spread, the ash will be wetted or incorporated.

We consider that the ash is a soil-conditioning agent without negative environmental impacts. The FDEP has advised Okeelanta that no Ash Management Plan needs to be submitted to the state to cover the spreading of ash on farmlands.

Quality Control

The standardized test to characterize the ash will be Method for Chemical Analysis of water and wastes, EPA-600/4-82. The tests will be conducted no less than once a month on a mixed product of fly ash and bottom ash for mercury, lead, arsenic, chromium, barium, selenium, silver, cadmium and copper.

There are no criteria established for the acceptance or rejection of ash materials. The control of ash quality will be at the source of the fuel, in particular the wood supplies which are required to meet strict standards, as noted in the Fuel Management Plan. The testing of ash will be performed to confirm further the quality of the fuel source and assist Osceola in its plans for spreading.

Additionally, stack tests will be performed in accordance with the FDEP air permit. These tests will be conducted with and without the mercury control system in operation thus providing an indication of the amount of mercury being removed.

C. COAL

The design of the Okeelanta Cogeneration Project includes the provision for the future installation of equipment and systems to allow the use of coal as a supplemental fuel. The following describes the FDEP air permit restrictions related to coal ash: coal ash (if collected as a result of coal firing) will be transported off site for disposal.

Ash Quantities

The maximum quantities of ash to be generated while burning a blend of coal and biomass are provided below:

Bottom Ash-4,000T/yr

Fly Ash-12,000 T/yr

The amount of ash generated has been calculated based upon the maximum amount of coal allowed to be burned per year under the conditions of the FDEP air permit.

System Description

The fly ash will be collected and stored through the same system as described for handling fly ash when firing wood or bagasse. However, the disposal of the coal fly ash will be handled in a different manner. Any fly ash collected when burning coal will not be disposed of by spreading on the sugar cane fields. The ash will be collected and removed from the silo and disposed of in a permitted landfill. The ash would be transported from the site in covered or pressure differential trucks depending upon the final design requirements.

The bottom ash would also be handled in the same manner as when firing wood or bagasse and ultimately stored in the bunkers prior to removal. Again, this ash would be removed to a certified landfill site.

Quality Control

Since coal ash has been classified as non-hazardous by the EPA and suitable for landfill disposal, we will not be performing any tests on the ash produced by the combination of coal or coal with biomass.

Upon the introduction of any amount of coal into the fuel feed system of the boilers, all ash generated will be treated as though it is 100% coal ash.

A. PERMIT CONDITIONS

Palm Beach County

The restrictions on fuel usage are covered by certain special conditions incorporated as part of the County's approval of Petition 92-14. These conditions reflect, in part, the air permit requirements issued by the Florida Department of Environmental Protection (FDEP) and under Use Limitations establish criteria for height of fuel storage areas, the definition of "biomass waste", restrictions on sulfur content of coal and fuel oil and the containment requirements for stored liquids such at fuels and oils.

Florida Dept. of Environmental Protection (FDEP) Air Permit

Acting under authority of the U.S. Environmental Protection Agency, FDEP has issued a final construction permit for the Okeelanta Power Limited Partnership (OPLP) cogeneration facility (Permit Number AC50-219413 *(PSD-FL-196)*). This permit allows construction of air pollution sources. The permit limits operating capacity of the facility to 74.9 MW and an average of 455,418 lb/hr steam. Allowed fuels are biomass, No. 2 fuel oil and coal. Use of coal is further limited to a 16 percent annual capacity factor (72,714 tons per year of coal).

Electrostatic precipitators for particulate matter control, selective non-catalytic reduction systems for nitrogen oxides control, and a mercury control system are required. Coal must contain no more than 0.7% sulfur, and No. 2 fuel oil must contain no more than 0.05% sulfur.

The permit limits emissions of all regulated pollutants, including SO_2, NOx, PM, CO, VOC, mercury, and other regulated pollutants. Extensive source testing is required to demonstrate compliance, and continuous emissions monitoring is required, as well as fuel and ash sampling and analysis. This permit constitutes best available control technology (BACT) for SO_2 emissions, and reasonable available control technology (RACT) for NOx and VOC emissions.

FDEP Industrial Wastewater Permit Restrictions on Fuel Usage

The FDEP industrial wastewater permit (No. IC50-228716) indicates that the facility will be biomass/oil/coal fired. Specific Condition No. 4 of the permit notes that the permit is valid only for the specific processes and operations (including the types and quantities of raw materials and chemicals) indicated in the application. Any changes in these which may result in altered characteristics of the discharge are not permitted without the prior approval of FDEP and modification of the permit.

B. BAGASSE

Use

Bagasse is a fibrous waste product resulting from the milling of sugar cane. It is being collected and transported by conveyor to the cogeneration plant for use as a fuel in a process which generates both steam and electricity. The mill will supply bagasse to the cogeneration project during the Grinding Season, normally from mid October to mid March the next year.

System Description

During the grinding season, the sugar mill will provide the cogeneration facility with bagasse at an average daily rate that will be 6,500 tons per day (tpd) and a maximum hourly rate of 270 tons per hour (tph).

The bagasse will be transferred from the mill to the cogeneration facility via the Bagasse Transfer Conveyor, at the design rate of 270 tph. The Bagasse Transfer Conveyor is equipped with a belt scale designed to monitor and record the rate and quantity of bagasse flowing to the facility.

A system of Chain Distribution Conveyors receive the bagasse at the boiler area and transfer the material to the boiler feeders or to the bagasse bypass and recycle subsystem which conveys the bagasse to a storage area on the site.

The fuel from the Chain Distribution Conveyors will be bottom discharged into the boiler feed system via discharge chutes. Each chute is provided with shut off gates which are manually operated.

The entire fuel conveying system is provided with the necessary controls and fire protection systems.

The maximum height of the bagasse pile will be 50 feet and its maximum size will be about 500 feet by 600 feet and will be in the location noted on the site plan as fuel storage area. The bagasse will have a moisture content in excess of 50%, minimizing the incidence of fugitive emissions. During periods when the pile surface dries out, the pile will be sprayed with water.

The design of the fire protection system for the plant includes a fire water distribution system, designed in accordance with appropriate NFPA standards, including piping, valves and yard hydrants. Hydrants will be located in strategic areas around the fuel storage area at a spacing of approximately 250 feet along the buried yard loop or branch line piping. Hydrants will be suitable for attaching hoses for manually fire fighting. Deluge water spray systems will be used for protection of the fuel handling equipment and the conveyors.

The pile will be spread, compacted and rotated to minimize the number of air pockets in the pile and the risk of fire. Also, as explained above, the pile will be dampened when viewed to be dry.

During operation of the plant, fuel pile management personnel will be on site 24 hours a day. Telephone communication will be used to contact the local fire department upon the occurrence of a fire incident. The plant operation maintenance manual will incorporate instructions on fire protection and fighting procedure and personnel will be given classroom instructions.

C. WOOD WASTE

Use

During the Non-grinding Season, normally from mid March to mid October, the bagasse is no longer available as a fuel and clean wood waste is used instead.

System Description

Wood waste will be delivered to the facility by trucks at an approximate design rate of 3,600 tons per day. The anticipated deliveries are 6 days per week, 12 hours per day. Each truck is anticipated to have a capacity of 25 tons of wood waste.

The trucks will be unloaded utilizing two hydraulically operated truck dumpers. A third unloading bay is provided to accommodate self-unloading trucks.

The wood waste will be discharged into three receiving hoppers equipped with chain conveyors which will transfer the wood to the Unloading Conveyor

The Unloading Conveyor which is equipped with a belt scale and a magnetic separator will convey the wood waste to the Screen and Hog Tower at a design rate of 300 tph.

The Screen and Hog Tower is an open facility at which the wood waste is discharged onto a disc screen which will separate the material sized less than 3” from the oversized material. The oversized material will be discharged to the Hog, which is a motor driven, size reducing piece of equipment which reduces the oversized wood to less than 3”, suitable to feed into the boiler.

The sized wood waste is then transferred from the Screen and Hog Tower by a radial stacker to a wood storage area (wood yard) on the site or directed to the boilers via Plant Feed Conveyor which is equipped with a belt scale for monitoring and recording the quantity of fuel delivered directly to the boilers.

The wood is reclaimed continuously at design rates of 175 tph of wood chips or 87.5 tph of wood chips combined with 135 tph of bagasse by two under pile chain reclaimers.

The reclaimed fuel is transferred to the cogeneration facility via the Plant Feed Conveyor and to the boiler feeders by the Chain Distribution Conveyors.

A Radial Stacker will form a circular pile approximately 50 feet in height which forms the base configuration of the entire storage pile. The pile shape and ultimate configuration is developed by the use of plant mobile equipment which spreads, compacts, and shapes the pile. The maximum height of the wood pile will be 50 feet and its maximum size will be 600 feet by 900 feet.

The wood will have a relatively high moisture content and, as noted below, only 15% will be less than 1/4” in size. Fugitive emissions will be controlled by water spraying as necessary.

Quality Control

The wood waste will be supplied to the Project under long-term contracts which include quality requirements reflecting the conditions of the FDEP air permit. In addition to quality tests at the supplier's facility, additional quality tests will be conducted at the Project on a regular basis.

The wood waste suppliers will collect and test a representative sample from each load of wood. One third of the sample will be available to Okeelanta for confirmation test. Tests will be conducted in accordance with ASTM E870-82 or successor standard. If the supplier's and Okeelanta's test results differ by more than 5% then a third sample will be submitted to an independent laboratory.

In accordance with the FDEP air permit the tests will be conducted on a weekly basis for the first year of operation and thereafter on a monthly basis. Upon delivery to the site, the wood waste will be stored in separate weekly piles, such that in the event the wood waste is determined not to be in accordance with the supplier's specification it can be readily identified and removed by the supplier.

The wood waste specification imposed on the supplier will be:

1. less than 1% by volume or weight shall be plastics, rubber, glass and painted wood.
2. free from chemically treated wood (e.g. chromium, copper and arsenic; creosote; or pentachlorophenol) except for incidental amounts, not to exceed 1% by volume or weight.
3. less than 5% shall be sand, soil or other organic material
4. moisture content shall be between 20% and 50% with a quarterly average of less than 40%.
5. 95% shall be less than 4" in size, 15% (on an individual load) will be less than 1/4" in size.

Osceola has the right to reject any load which does not meet any one of the above requirements, and the supplier will be required to remove the delivered amount from the site.

However, if the wood waste exceeds the specification limits for sand, soil, inorganic material or moisture content, Osceola may accept the material provided that the supplier reduces its handling and processing costs by a predetermined rate.

D. FUEL OIL

Use

Fuel oil will be used for two primary purposes - i) for start-up of the boilers **,** and ii) as a fuel for the on-site vehicles and heavy mobile equipment.

System Description

No. 2 fuel oil will be used as a startup fuel for the boilers. The fuel oil system will consist of a truck unloading facility, a 50,000 gallon fuel oil storage tank, two fuel oil transfer pumps, a fuel oil dispensing station, and associated piping, valves, and instrumentation. Detailed plans of the fuel storage system will be submitted to the Department of Environmental Resources Management prior to construction.

Spill Protection and Clean Up

The fuel oil will be stored in an enclosed tank surrounded by a berm which will be sized to contain the full capacity of the tank in the event of a spill. The tank will be located at a distance from the plant in accordance with the NFPA separation requirements. The area around the fuel tank will be serviced by hydrants connected to the fire system yard loop. Any spilled oil will be collected and taken off-site for proper disposal.

Quality Control

Due to the limited use of fuel oil (as a start—up fuel only), there will be no testing procedures employed. The fuel oil will be purchased as low sulfur fuel (0.05% in accordance with the FDEP air permit) on the spot market.

The only acceptance criteria to be used for fuel oil will be that the sulfur content is not greater than 0.05%.

E. COAL

The design of the Okeelanta project includes provisions for the installation of equipment and systems to use coal as a supplemental fuel, its use being restricted by the FDEP air permit. The plant will be designed with space allocated for equipment to receive, unload, store, retrieve and fire coal. The use of coal requires construction of additional systems and facilities of the plant. Implementation of coal firing will be predicated upon the experienced reliability of the wood supplies and the prediction of the future economics of wood supplies. The project will have a number of long term wood supply contracts in place which will satisfy the needs of the project for at least 15 years. Independent studies of the wood supplies in Florida indicate that a continually increasing quantity will be available. However, due to the long term obligation of the project to supply Florida Power and Light Company with electrical energy for 30 years, the plant has been permitted to allow limited coal firing.

The following describes the permit restrictions issued by the FDEP regarding the use of coal as a fuel and the plan we expect to implement, in the event the decision is made to fire coal.

Delivery and Unloading

The most efficient method to deliver coal to the site is by rail. The project would construct a spur line from the existing rail line, located to the south of the Okeelanta Mill, into the site area. Under the terms of the air permit, the maximum number of cars required would be 600 per year.

A truck unloading capability would also be provided.

Storage and Retrieval

Coal unloaded at the unloading facility will be conveyed on a covered conveyor to a stacking tower. The coal will be stored in two distinct piles - i) an active pile, from which coal is withdrawn on a regular basis, and ii) an inactive pile which provides a back—up source of fuel and is used only in emergency situations. The active pile will be constantly used with coal being withdrawn from it by means of mobile equipment loading into a hopper. The hopper will deliver the coal onto a covered conveyor for delivery to the day hoppers. The coal will then be fed to the boilers as required from the day hoppers.

The inactive pile will be established by moving excess coal from the active pile by mobile equipment. The inactive coal pile will be compacted and treated to minimize fugitive emissions.

The maximum height of the coal pile will be 50 feet and its maximum size is not expected to exceed two acres. At any time that a coal pile has remained unused for a three month period, the pile will be treated with an encrusting agent to minimize fugitive emissions.

The design of the fire protection system for the plant includes a fire water distribution system, designed in accordance with appropriate NFPA standards, including piping, valves and yard hydrants. Hydrants will be located in strategic areas around the fuel storage area at a spacing of approximately 250 feet along the buried yard loop or branch line piping. Hydrants will be suitable for attaching hoses for manually fire fighting. Deluge water spray systems will be used for protection of the fuel handling equipment and the conveyors.

The pile will be spread and compacted to minimize the number of air pockets in the pile and the risk of fire. Also, the pile will be dampened when viewed to be dry.

During operation of the plant, fuel pile management personnel will be on site 24 hours a day. Telephone communication will be used to contact the local fire department upon the occurrence of a fire incident. The plant operation maintenance manual will incorporate instructions on fire protection and fighting procedure and personnel will be given classroom instructions.

The fire protection system is not yet designed. However, during the design process, the Palm Beach County Fire and Rescue office will be contacted to assure that its requirements are incorporated in the final design.

Quality Control

ASTM D-2234 will be used as guidance for the collection of a coal sample and ASTM D-2013 will be used for the analysis of the sample. The analysis will determine:

Heating value, BTU/lb
Moisture content, %
Ash content, %
Sulfur content, %

The sampling and testing by an independent laboratory will be conducted for each delivery. Samples will be collected and tested at the source and test results forwarded to Osceola for receipt prior to delivery of the coal. The limit for sulfur content as contained in the FDEP air permit is 0.7%.

Operational testing, including emissions ash testing, will provide additional information about the properties of the coal fired.

Under the terms of the coal supply contract the supplier will be requested to meet certain criteria relating to heating value, moisture ash and sulfur content. Any load which does not meet any one of these criteria, is subject to rejection by Okeelants and the supplier will be responsible for its removal from site. The project will also have the right to conduct spot check analyses on deliveries to confirm the information submitted by the supplier.

Regular operational testing, such as the Continuous Emissions Monitoring and ash testing, will provide additional information relating to the quality of the coal.

Wood-Waste and Ash Inspection and Testing Plan

Okeelanta Generating Plant

June 1995

Prepared by

Okeelanta Power Limited Partnership

Okeelanta Generating Plant
6 miles Sosuth of Suoth Bay on U.S. Highway 27
South Bay, Florida 33493

Submitted to
Florida Department of Environmental Protection
Bureau of Air Regulation

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References:

Bechtel Drawing 22433-M-03 1-0140-02; “Fuel Handling System Flow Diagram”

Bechtel Drawings 22433-M73-JN-O01 and 22433-M73-JM-0O1; “Fly Ash and Bottom Ash Handling System Flow Diagrams

1.0 INTRODUCTION

The Okeelanta Power, L.P. (OPLP) is constructing a bagasse/wood-waste fired cogeneration plant, known as the Okeelanta Generating Plant (OGP), adjacent to the site of the Okeelanta Sugar Mill. The OGP is located approximately six miles south of the town of South Bay in Palm Beach County, Florida.

As a provision of the OGP s Florida Department of Environmental Protection (FDEP) Air Permit (AC50-219413, PSD-FL-196), the plant is required to implement inspection and testing procedures for the wood-waste and other materials delivered to the plant for fuel. The primary function of these procedures is to keep painted and chemically-treated wood, household garbage, toxic or hazardous non-biomass, and non-combustible waste material from being burned at the plant. In addition, the FDEP Air Permit also requires the sampling and analysis of ash from the biomass burned in order to determine the concentration of copper, chromium, and arsenic present. This Wood-Waste and Ash Inspection and Testing Plan describes the implementation of these procedures during operation of the OGP to ensure compliance with the sampling and analysis provisions outlined in the air permit

The Plan includes a brief description of the OGP and its operations related to wood-waste and ash handling in Sections 2.0 and 3.0. Procedures for inspection, sampling, and analysis of the wood-waste at both the wood-waste supply sites and at the OGP, as well as procedures for ash sampling and analysis are described in Section 4.0. The OGP procedures for recordkeeping of inspections, sampling, and analysis results are provided in Section 5.0. Drawings for the fuel and ash handling systems, showing inspection (wood-waste only) and sampling locations are provided in the appendix.

2.0 FACILITY INFORMATION

The Okeelanta Generating Plant (OGP) is a new 74.9 MW (gross) bagasse and wood-waste fired cogeneration plant located in South Bay, Florida, adjacent to the existing Okeelanta Sugar Mill. The plant is designed to supply high and low pressure steam to the Okeelanta Sugar Mill during the grinding season (mid-October to April) while burning bagasse as the primary fuel. During the non-grinding season the OGP is designed to provide low pressure steam while using processed wood-waste as the primary fuel. Steam generation will be accomplished by means of bagasse and wood-waste fired non-reheat boilers.

Electrical power generation will be provided by means of an extraction-condensing turbine generator and will be used to meet in-house loads and for sale to Florida Power & Light.

The major components of the plant include:

- three balanced draft bagasse/wood-fired boilers with membrane wall construction, superheater, and economizer (boilers are also permitted for future coal firing to a maximum of 25 % of rated heat input)
- three electrostatic precipitators (one/boiler) with integral stacks
- an extraction-condensing turbine generator
- material storage and handling systems (e.g., wood-waste, bagasse, ash)
- ancillary plant equipment.

3.0 PROCESS DESCRIPTIONS

The following sub-sections describe the OGP wood-waste and ash handling systems from a "process flow" standpoint. Although the OGP also includes a bagasse handling system which operates during the sugar cane grinding season, only the wood-waste and ash are subject to the sampling and analysis requirements of the OGP air permit. Therefore, only these systems are described in this plan.

3.1 Wood-Waste Handling System

The following description of the Wood-Waste Handling System is depicted schematically on the wood-waste/bagasse flow diagram (Bechtel Drawing #22433-M-031-0140-02) contained in the appendix .

Wood-waste will be delivered to the OGP by 25-ton trucks (typical) at an approximate design rate of 1,200 tons per day, with deliveries anticipated 12 hours per day, 6 days per week. The trucks will be unloaded at the OGP utilizing two hydraulically operated truck dumpers. A third unloading area will also be provided to accommodate any self-unloading trucks that may be available for fuel transportation.

While unloading from the trucks, the wood-waste will be discharged into receiving hoppers equipped with live bottom chain conveyors which will transfer the wood material to the 48" Unloading Conveyor. The Unloading Conveyor, which is equipped with a belt scale and magnetic separator, will convey the wood-waste to the Screen and Hog Tower at a design rate of up to 300 tons per hour (tph) .

The Screen and Hog Tower is an open facility consisting of a disc screen and a motor-driven, size-reducing hog. The wood-waste will be discharged onto the disc screen which acts to separate material sized less than 3" from any oversized material. The oversized material (i.e., > 3") is discharged to the Hog which reduces the wood pieces to the less than 3" size, suitable for feeding into the boilers.

The sized wood-waste is transferred from the Screen and Hog Tower via the Storage Conveyor to the Radial Stacker Conveyor which deposits the sized wood-waste at the wood storage area.

Sized wood-waste is reclaimed from the wood pile at a design rate of up to 175 tph through the use of two under-pile chain reclaimers. The reclaimers transfer the sized wood-waste to the Boiler Feed Conveyor which deposits the fuel on to one of two chain distribution conveyors for apportionment into the boilers.

3.2 Ash Handling Systems

The ash handling systems at the OGP comprises equipment from two distinct systems, (1) the handling of bottom ash from the boilers, and (2) the handling of fly ash collected in the electrostatic precipitators (ESP), the dust collector hoppers and the air heater hoppers. Therefore, the following two sub-sections provide separate discussions of both the equipment related to bottom ash handling and the equipment for fly ash handling. A process flow diagram of these ash handling systems is also provided in the appendix

to this plan (Bechtel Drawings #22433 M73-JN-0O1 and #22433 M73-JM-0O1) .

3.2.1 Bottom Ash Handling

Bottom ash will be continuously discharged from the boilers into three water-submerged drag chain conveyors. Each conveyor will consist of a wet compartment and a dry lower compartment. The upper compartment will be a water-tight steel trough designed to contain the water required for quenching and cooling the bottom ash to 1400 F. The trough will be sized to accommodate up to two hours of bottom ash generated from the combustion of wood-waste (or bagasse).

The dewatered ash from the dewatering inclined ramp of the chain conveyor will be discharged into an 8 tph transfer conveyor from each individual boiler which will then transfer the dewatered ash into a 25-tph collecting conveyor. The collecting conveyor will unload the ash into a three-sided bunker, sized to a capacity of approximately 1-day of normal ash generation. Mobile equipment will be used to reclaim and load the stored ash into trucks for disposal off site.

3.2.2 Fly Ash Handling

Fly ash at the OGP will include ash collected in the air heater hoppers, dust collector hoppers and from the ESP hoppers. The fly ash handling system will encompass the removal and transport of the fly ash from the hoppers to a storage silo using a dry chain conveyor and bucket elevator conveyor system.

The fly ash collected from the air heaters and ESPs will discharge via enclosed chutes to the collecting fly ash chain conveyor. The collecting conveyor transfers the ash to the bucket elevator conveyor, which in turn carries the ash up to the flight chain conveyor. The flight conveyor discharges the fly ash into the top of the ash storage silo. The conveying capacity of this system will be sufficient to remove 24-hours of ash generation in 6 to 8 hours of operation.

The ash storage silo will be sized to accommodate 1,500 tons (approximately 7 days of ash generation) of fly ash. The silo will be a conical-bottom cylinder-type carbon steel structure. Two twin shaft pug-mill conditioner unloaders, rated at 200 tph each, will discharge the ash into trucks for disposal.

4.0 INSPECTION, SAMPLING, AND ANALYSIS PROCEDURES

As stated in Section 1.0, the FDEP Air Permit for the OGP requires that inspection, sampling, and analysis of the wood-waste burned, and sampling and analysis of the ash generated at the plant, be performed to demonstrate that contaminants, principally copper, chromium, arsenic, in the biomass burned in the boilers are minimized.

The specific inspection and sampling procedures to be utilized at each stage of the wood-waste and ash handling systems are provided in the following sub-sections.

4.1 Wood-Waste Supply Sites.

As stipulated in the OGP fuel supply contracts with the wood-waste suppliers, the delivered wood-waste must be substantially free of plastics, rubber, glass, and painted wood and contain only incidental amounts of chemically treated wood (e.g., chromium, copper, arsenic, creosote, pentachlorophenol).

To help ensure that wood-waste delivered to the OGP meets the provisions of the air permit, as well as other fuel quality specifications, the wood waste suppliers will perform inspection and material segregation operations on each load of feedstock received at their facilities. Although the OGP will obtain wood-waste fuel from several different suppliers with a variety of sources for their unprocessed feedstock, the following description of the inspection and material segregation operations are typical of those operations performed at wood yards supplying the OGP.

The bulk material feedstock at the originating wood yards will first undergo a “gross” material separation by removing the bulk wood-waste from other mixed wastes (e.g., plastics, non-wood debris, scrap metal, concrete/soils) through the use of heavy equipment, magnetic separation, and mechanical screening.

Trained personnel will be involved in oversight at this level of material segregation such that the majority of prohibited wastes are removed from the bulk wood-waste. After this operation, the wood-waste will be further visually inspected and manually sorted (when applicable) to remove chemically-treated and painted wood, smaller mixed wastes, and other non-combustible materials. The "sorted" wood-waste is then mechanically sized and screened (to actual contract specifications) .prior to delivery to the OGP site.

As a quality assurance measure, each fuel supplier's operations will be reviewed at least once monthly through an unannounced site inspection by OGP personnel. These visits will allow OGP to ensure that the supplier's inspection and segregation efforts remain at acceptable levels.

4.2 OGP Wood Yard Storage

In accordance with the FDEP Air Permit, analysis of wood-waste to be burned at the plant will conducted on a weekly basis for the first year of operation at the OGP. Thereafter, upon approval of FDEP, sampling and analysis may be reduced to a monthly basis.

Upon delivery of the wood-waste to the OGP, each load will be visually inspected by the Fuel/Ash Handler stationed at the truck receiving dumping area. Loads which contain unacceptable, visible amounts (i.e., greater than fuel contract specified limits) of chemically treated and/or painted wood and other prohibited mixed wastes will be rejected by the inspector and prevented from discharging at the OGP fuel storage area. If the delivered load is acceptable based on the visual inspection, the truck will be staged for unloading.

Sampling of the wood-waste will occur at the OGP fuel storage yard. Representative samples will be taken from specified sections of the wood-waste pile which represent and include the fuel to be reclaimed and burned during the following week of plant operation. These "weekly" sections, and their schedule for reclamation and burning, will be identified and approved by the Plant Manager (or designee) prior to samples being taken.

A total of three grab samples will be taken from different areas and depths at the specified "weekly" section of the fuel pile. Each grab sample will be approximately one pound and will be stored in sealable plastic (ziplock-type) bags.

Prior to releasing the samples for outside lab analysis, a "composite sample" will be produced by combining the three individual grab samples into a homogeneous mixture and cutting out a single sample from the mixture as specified by the lab performing the analyses. This "composite sample" will represent the composition of the wood-waste to be burned during the following week of plant operations. The remaining portion of the homogenous mixture will be retained onsite for use as a control sample to the verify lab test results, if necessary.

Laboratory results on the samples will typically be available to the OGP Fuels Manager within 2-3 days of receipt of the sample at the lab. Any results which indicate contamination of the wood-waste in the "weekly" section of the pile by copper, chromium, and/or arsenic in concentrations above the air permit-specified limits (i.e., 62.8 ppm copper, 83.3 ppm chromium, and 70.7 ppm arsenic) will be immediately investigated by the onsite Environmental, Health and Safety Representative (EH&S). The "weekly" section of the pile tested will not be burned until additional testing of the control sample is undertaken to verify the original test results. If necessary, additional sampling/testing will be performed to determine the extent of contaminated wood-waste in the "weekly" section of the fuel pile.

4.3 Bottom Ash/Fly Ash

In accordance with the FDEP Air Permit, analysis of the ash generated at the OGP will conducted on a monthly basis for the first year of operation. Results from the analyses will be used to confirm that the air permit-specified limits on the concentration of copper, chromium, and arsenic in the biomass combusted at the OGP are being met. Three ash products will be analyzed:

1. Fly ash collected from the air heater, dust collectors, and ESP hoppers,
2. Bottom ash from the three boilers,
3. A mixed product of fly ash and bottom ash.

Grab samples of the bottom ash will be obtained weekly by the Chemical Technician as material is loaded from the storage bunker to trucks for offsite disposal. Fly ash grab samples will be obtained (also by the Chemical Technician) weekly from the transfer point between the collecting fly ash chain conveyor and the bucket elevator conveyor, as ash is loaded into the silo. The individual sample size for the bottom ash and fly ash grab samples will be approximately one pound each.

Prior to releasing the ash samples for outside lab analysis, a "combined ash sample" for the facility will also be produced by blending a portion of the individual weekly bottom and fly ash samples (approximately 8, 1 lb samples per month) into a homogeneous composite (fly and bottom ash) ash sample. A portion of the remaining individual fly ash, bottom ash, and combined ash samples will be retained on site as control samples for verification of lab test results, if necessary.

As stated in the air permit, the monthly ash samples will be analyzed for copper, chromium, and arsenic in accordance with appropriate analytical procedures per 40 CFR 261, Appendix III, described in SW-846, *Test Methods for Evaluating Solid Waste, Physical/Chemical Methods*. Laboratory results on the sample will typically be available to the OGP Fuels Manager within 2-3 days after receipt of the sample at the lab.

Any results on the representative monthly composite ash sample which indicate the burning of wood-waste with concentrations of copper, chromium and/or arsenic above of the air permit limits will be investigated by the EH&S Representative. Re-testing of the control ash sample will be performed to verify the original lab test results. Comparison of the ash sample results with the corresponding fuel test results will also be performed to ensure that existing material segregation and sampling procedures for the wood-waste provide for an accurate representation of the composition of the wood-waste burned at the facility.

4.4 Analysis Result Correlation

Results from the wood-waste, bottom ash, fly ash, and combined fly/bottom ash product sampling and analysis will be correlated so that a comparison of the analyzed metals content in the feedstock (wood-waste) with that of the ash products can be made. This information will be used to assess the adequacy of the wood-waste sampling procedures and for determining the distribution of the initial wood-waste metals content in the fly and bottom ash products. In addition, this information may be used to support a future request by OGP for FDEP to relax the sampling and analysis requirements of this plan.

5.0 RECORDKEEPING

As required by the OGP air permit, results from the weekly wood-waste and monthly ash analyses will be included in the Stack Monitoring Reports submitted quarterly to FDEP's South and Southeast district Offices and the Palm Beach County Health Unit. Specifically, FDEP will be notified of:

- Any analysis results which indicate exceedances of the allowable concentrations of copper, chromium, and arsenic.
- Any re-sampling/re-analysis and handling ("blending") of the wood-waste performed in the event an exceedance is indicated by the original analysis.
- The ultimate disposal of the off-specification material.

In addition, records on the various wood-waste inspections and wood-waste and ash sampling and analysis procedures outlined in this Plan will be maintained at the OGP for review on an as-requested basis by FDEP. The records will typically include:

- Fuel delivery information (e.g., supplier, time/date of delivery, type of material, delivery size)
- Written inspection reports (stating findings) of unannounced site visits to wood-waste suppliers to determine adequacy of their material segregation operations
- Wood-waste and ash sampling and analysis information (e.g., time/date of sampling, locations selected from the "weekly" sections, any atypical conditions, labs utilized, sample results) .

These records may also be used by OGP personnel in investigating potential non-compliance events and verifying fuel and ash test results.

Appendix H-1, Permit History/Id Number Changes
Okeelanta Corporation Final Permit No.: 0990005-012-AV

Facility ID Nos.: 0990005 & 0990332

Sugarcane Processing Facility: 0990005
Cogeneration Facility: 0990332

Permit History (for tracking purposes):

EU ID No.	Description	Permit No(s).	Issue Date	Exp. Date.	Revised Date
014	**Mill Boiler No. 16**				
	AC – Initial	AC50-191876/PSD-FL-169	7/29/91	3/1/93	-
	AC – Modification	AC50-191876/PSD-FL-169	-	-	2/18/93
	AC – Amendment	AC50-191876/PSD-FL-169	-	-	3/19/93
	AC – Amendment	AC50-191876/PSD-FL-169	-	-	3/7/94
	AO – Operating/COCOC	AO50-257065	11/29/94	11/29/99	-
	AO – Extension	AO50-257065	-	Note 1	-
	AC – Modification	0990005-009-AC/PSD-FL-169A	10/30/01	11/01/03	
015	**Volatile Organic Liquid Storage Vessels (NSPS Kb)**				
	AC – Initial (After-the-Fact)	AC50-265485	5/22/95	Note 2	-
016	**Volatile Organic Liquid Storage Vessels (NSPS Kb)**				
	AC – Initial (After-the-Fact)	AC50-265485	5/22/95	Note 2	-
017	**Volatile Organic Liquid Storage Vessels (NSPS Kb)**				
	AC – Initial (After-the-Fact)	AC50-265485	5/22/95	Note 2	-
018	**Central Vacuum System for the Trans-Shipment Facility**				
	AC – Initial (After-the-Fact)	0990005-001-AC	1/24/96	Note 2	-
	AC – Construction	0990005-008-AC	05/10/01	05/10/06	

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Permit History (for tracking purposes):

EU ID No.	Description	Permit No(s).	Issue Date	Exp. Date.	Revised Date
019	**Packaging Lines**				
	AC – Initial (After-the-Fact)	0990005-001-AC	1/24/96	Note 2	-
	AC – Construction	0990005-008-AC	05/10/01	05/10/06	
020	**Sugar Grinder and Hopper**				
	AC – Initial (After-the-Fact)	0990005-001-AC	1/24/96	Note 2	-
	AC – Construction	0990005-008-AC	05/10/01	05/10/06	
021	**Central Dust Collection System No. 1 (Wet Rotoclone #1)**				
	AC – Initial (After-the-Fact)	0990005-002-AC	7/17/96	Note 2	-
	AC – Construction	0990005-005-AC	01/19/01	07/19/06	
022	**Central Dust Collection System No. 2 (Wet Rotoclone #2)**				
	AC – Initial (After-the-Fact)	0990005-002-AC	7/17/96	Note 2	-
	AC – Construction	0990005-005-AC	01/19/01	07/19/06	
023	**Cooler No. 1 (Cyclone #1)**				
	AC – Initial (After-the-Fact)	0990005-002-AC	7/17/96	Note 2	-
	AC – Construction	0990005-005-AC	01/19/01	07/19/06	
024	**Cooler No. 2 (Cyclone #2)**				
	AC – Initial (After-the-Fact)	0990005-002-AC	7/17/96	Note 2	-
	AC – Construction	0990005-005-AC	01/19/01	07/19/06	

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Permit History (for tracking purposes):

EU ID No.	Description	Permit No(s).	Issue Date	Exp. Date.	Revised Date
025	**Fluidized Bed Dryer/Cooler**				
	AC – Initial	0990005-002-AC	7/17/96	Note 2	-
	AC – Construction	0990005-005-AC	01/19/01	07/19/06	
026	**Sugar Silo (S1101)**				
	AC – Initial (After-the-Fact)	0990005-001-AC	1/24/96	Note 2	-
	AC – Construction	0990005-008-AC	05/10/01	05/10/06	
027	**Sugar Silo (S1102)**				
	AC – Initial (After-the-Fact)	0990005-001-AC	1/24/96	Note 2	-
	AC – Construction	0990005-008-AC	05/10/01	05/10/06	
028	**Sugar Silo (S1103)**				
	AC – Initial (After-the-Fact)	0990005-001-AC	1/24/96	Note 2	-
	AC – Construction	0990005-008-AC	05/10/01	05/10/06	
029	**Materials Handling and Storage Operations (Cogeneration Facility)**				
	AC – Initial	AC50- & PSD-FL-	9/27/93	-	-
	AC – Modification	AC50- & PSD-FL-	10/16/95	-	-
	AC – Extension	AC50- & PSD-FL-	-	Note 2	-

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Sugarcane Processing Facility: 0990005
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Permit History (for tracking purposes):

EU ID No.	Description	Permit No(s).	Issue Date	Exp. Date.	Revised Date
030	**Cogeneration Boiler No. 1 (Cogeneration Facility)**				
	AC – Initial	AC50-219413 & PSD-FL-196	9/27/93	-	-
	AC – Extension	AC50-219413 & PSD-FL-196	-	Note 2	-
	AC – Amendment	AC50-219413 & PSD-FL-196(A) FDEP File 0990332-001-AC	-	-	02/20/96
	AC – Amendment	AC50-219413 & PSD-FL-196(B) FDEP File 0990332-002-AC	-	-	06/14/96
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-003-AC	-	-	01/22/97
	AC – Amendment	AC50-219413 & PSD-FL-196(C) FDEP File 0990332-005-AC	-	-	04/05/97
	AC – Amendment	AC50-219413 & PSD-FL-196(D) FDEP File 0990332-004-AC	-	-	04/18/97
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-007-AC	-	-	05/08/97

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Facility ID Nos.: 0990005 & 0990332

Sugarcane Processing Facility: 0990005
Cogeneration Facility: 0990332

Permit History (for tracking purposes):

EU ID No.	Description	Permit No(s).	Issue Date	Exp. Date.	Revised Date
	AC – Amendment	AC50-219413 & PSD-FL-196(A) FDEP File 0990332-003-AC	-	-	09/02/97
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-006-AC	-	-	10/24/97
	AC – Withdrawn	AC50-219413 & PSD-FL-196(G) FDEP File 0990332-008-AC	-	-	02/03/98
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-009-AC	-	-	06/15/98
	AC – Amendment	AC50-219413 & PSD-FL-196(F) FDEP File 0990332-010-AC	-	-	06/24/99
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-012-AC	-	-	12/22/99
	AC – Amendment	AC50-219413 & PSD-FL-196(K) FDEP File 0990332-011-AC	-	-	11/06/00
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-013-AC	-	-	01/24/01
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-014-AC	-	-	01/31/02

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Permit History (for tracking purposes):

EU ID No.	Description	Permit No(s).	Issue Date	Exp. Date.	Revised Date
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-015-AC	-	-	05/04/01
	AC – Amendment	AC50-219413 & PSD-FL-196(O) FDEP File 0990332-016-AC	-	-	Pending
031	**Cogeneration Boiler No. 1 (Cogeneration Facility)**				
	AC – Initial	AC50-219413 & PSD-FL-196	9/27/93	-	-
	AC – Extension	AC50-219413 & PSD-FL-196	-	Note 2	-
	AC – Amendment	AC50-219413 & PSD-FL-196(A) FDEP File 0990332-001-AC	-	-	02/20/96
	AC – Amendment	AC50-219413 & PSD-FL-196(B) FDEP File 0990332-002-AC	-	-	06/14/96
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-003-AC	-	-	01/22/97
	AC – Amendment	AC50-219413 & PSD-FL-196(C) FDEP File 0990332-005-AC	-	-	04/05/97
	AC – Amendment	AC50-219413 & PSD-FL-196(D) FDEP File 0990332-004-AC	-	-	04/18/97
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-007-AC	-	-	05/08/97

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Sugarcane Processing Facility: 0990005
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EU ID No.	Description	Permit No(s).	Issue Date	Exp. Date.	Revised Date
	AC – Amendment	AC50-219413 & PSD-FL-196(A) FDEP File 0990332-003-AC	-	-	09/02/97
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-006-AC	-	-	10/24/97
	AC – Withdrawn	AC50-219413 & PSD-FL-196(G) FDEP File 0990332-008-AC	-	-	02/03/98
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-009-AC	-	-	06/15/98
	AC – Amendment	AC50-219413 & PSD-FL-196(F) FDEP File 0990332-010-AC	-	-	06/24/99
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-012-AC	-	-	12/22/99
	AC – Amendment	AC50-219413 & PSD-FL-196(K) FDEP File 0990332-011-AC	-	-	11/06/00
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-013-AC	-	-	01/24/01
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-014-AC	-	-	01/31/02

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EU ID No.	Description	Permit No(s).	Issue Date	Exp. Date.	Revised Date
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-015-AC	-	-	05/04/01
	AC – Amendment	AC50-219413 & PSD-FL-196(O) FDEP File 0990332-016-AC	-	-	Pending
032	**Cogeneration Boiler No. 1 (Cogeneration Facility)**				
	AC – Initial	AC50-219413 & PSD-FL-196	9/27/93	-	-
	AC – Extension	AC50-219413 & PSD-FL-196	-	Note 2	-
	AC – Amendment	AC50-219413 & PSD-FL-196(A) FDEP File 0990332-001-AC	-	-	02/20/96
	AC – Amendment	AC50-219413 & PSD-FL-196(B) FDEP File 0990332-002-AC	-	-	06/14/96
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-003-AC	-	-	01/22/97
	AC – Amendment	AC50-219413 & PSD-FL-196(C) FDEP File 0990332-005-AC	-	-	04/05/97
	AC – Amendment	AC50-219413 & PSD-FL-196(D) FDEP File 0990332-004-AC	-	-	04/18/97
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-007-AC	-	-	05/08/97

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EU ID No.	Description	Permit No(s).	Issue Date	Exp. Date.	Revised Date
	AC – Amendment	AC50-219413 & PSD-FL-196(A) FDEP File 0990332-003-AC	-	-	09/02/97
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-006-AC	-	-	10/24/97
	AC – Withdrawn	AC50-219413 & PSD-FL-196(G) FDEP File 0990332-008-AC	-	-	02/03/98
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-009-AC	-	-	06/15/98
	AC – Amendment	AC50-219413 & PSD-FL-196(F) FDEP File 0990332-010-AC	-	-	06/24/99
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-012-AC	-	-	12/22/99
	AC – Amendment	AC50-219413 & PSD-FL-196(K) FDEP File 0990332-011-AC	-	-	11/06/00
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-013-AC	-	-	01/24/01
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-014-AC	-	-	01/31/02

Appendix H-1, Permit History/Id Number Changes
Okeelanta Corporation Final Permit No.: 0990005-012-AV

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Permit History (for tracking purposes):

EU ID No.	Description	Permit No(s).	Issue Date	Exp. Date.	Revised Date
	AC – Amendment	AC50-219413 & PSD-FL-196 FDEP File 0990332-015-AC	-	-	05/04/01
	AC – Amendment	AC50-219413 & PSD-FL-196(O) FDEP File 0990332-016-AC	-	-	Pending
033	**Cogeneration Facility NSPS Storage Tank**				
	AC/AO	Rule 62-210.300(b)(3), F.A.C. (Temporary Exemption)			
034	**Bulk Load-out Operation**				
	AC- Construction	0990005-005-AC	01/19/01	07/19/06	
035	**Transfer Bulk Load-out Operation**				
	AC- Construction	0990005-005-AC	01/19/01	07/19/06	
048	**Paint Booth**				
	AC- Construction	0990005-010-AC	08/22/01	08/22/06	

Notes:

1 - AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.
2 - AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.
{Rule 62-213.420(1)(b)2., F.A.C., allows Title V Sources to operate under existing valid permits that were in effect at the time of application until the Title V permit becomes effective.}

Okeelanta Corporation Final Permit No.: 0990005-012-AV
Facility ID Nos. 0990005 & 0990332

Includes the following three attachments submitted in the November 4, 2002 Permit Revision Application, required by Specific Condition 8. of Construction Permit 0990332-014-AC/PSD-FL-196M, dated January 31, 2002.

Attachment OC-EU4-J3, Detailed Description of Control Equipment
Attachment OC-EU4-J6, Procedure for Startup and Shutdown
Attachment OC-EU4-J7, Operation and Maintenance Plan

Appendix R-1, Applicable / Non-Applicable Rules has been added at the applicants request through Golder Associates, Inc. and is included for information purposes c
It does not imply the endorsement of the list by the Department.

EU ID 003 : Sugar Mill Boiler No. 4 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
NON-APPLICABLE	60 Subpart A	40CFR60.1	Subpart A -- General Provisions	Boiler No. 4 is not subject to NSPS.
NON-APPLICABLE	60 Subpart D	40CFR60.40	SubPart D -- Applicability and designation of affected facility	Boiler No. 4 was constructed prior to August 17, 1971, and has not been modified or reconstructed after this date.
NON-APPLICABLE	60 Subpart Db	40CFR60.40b	Subpart Db -- Applicability and delegation of authority	Boiler No. 4 was constructed prior to June 19, 1984, and has not been modified or reconstructed after this date.
NON-APPLICABLE	60 Subpart Dc	40CFR60.40c	Subpart Dc -- Small Industrial - Commercial - Institutional Steam Generating Units -- Applicability	Boiler No. 4 was constructed prior to June 9, 1989, and has not been modified or reconstructed after this date. In addition, Boiler No. 4 has a heat input of greater than 100 MMBtu/hr.
APPLICABLE	62-210	62-210	STATIONARY SOURCES - GENERAL REQUIREMENTS	
APPLICABLE	62-210	62-210.700	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(1)	EXCESS EMISSIONS	
NON-APPLICABLE	62-210	62-210.700(2)	EXCESS EMISSIONS	Boiler No. 4 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-210	62-210.700(3)	EXCESS EMISSIONS	Boiler No. 4 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-210	62-210.700(4)	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(5)	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(6)	EXCESS EMISSIONS	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
NON-APPLICABLE	62-296 <	62-296.320(4)(b)	General Pollutant Emission Limiting Standards.	A visible emission standard set forth elsewhere in Rule 62-296 applies to Boiler No. 4.
NON-APPLICABLE	62-296 <	62-296.405	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	Boiler No. 4 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Boiler No. 4 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	
APPLICABLE	62-296 <	62-296.410(1)	Carbonaceous Fuel Burning Equipment.	
NON-APPLICABLE	62-296 <	62-296.410(1)(a)	Carbonaceous Fuel Burning Equipment.	Boiler No. 4 has a maximum heat input capacity of greater than 30 MMBtu/hr.
APPLICABLE	62-296 <	62-296.410(1)(b)	Carbonaceous Fuel Burning Equipment.	
NON-APPLICABLE	62-296 <	62-296.410(2)	New Emissions Units.	Boiler No. 4 was issued a permit prior to July 1, 1974.
APPLICABLE	62-296 <	62-296.410(3)	Test Methods and Procedures.	
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facili	
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)		
NON-APPLICABLE	62-296 >	62-296.570(1)(b)		Boiler No. 4 is not exempt from permiitting.
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)1.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)2.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)3.	Operation Permit Requirements.	
NON-APPLICABLE	62-296 >	62-296.570(4)(a)4.	Operation Permit Requirements.	Boiler No. 4 does not have a CEMS.
APPLICABLE	62-296 >	62-296.570(4)(b)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.

EU ID 003 : Sugar Mill Boiler No. 4 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	**62-297**	**62-297**	**STATIONARY SOURCES - EMISSIONS MONITORING**	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.310(1)	Required Number of Test Runs.	
APPLICABLE	62-297	62-297.310(2)	Operating Rate During Testing.	
NON-APPLICABLE	62-297	62-297.310(2)(a)	Operating Rate During Testing.	Boiler No. 4 is not a combustion turbine.
APPLICABLE	62-297	62-297.310(2)(b)	Operating Rate During Testing.	
APPLICABLE	62-297	62-297.310(3)	Calculation of Emission Rate.	
APPLICABLE	62-297	62-297.310(4)	Applicable Test Procedures.	
APPLICABLE	62-297	62-297.310(5)	Determination of Process Variables.	
APPLICABLE	62-297	62-297.310(6)	Required Stack Sampling Facilities.	
APPLICABLE	62-297	62-297.310(7)	Frequency of Compliance Tests.	
APPLICABLE	62-297	62-297.310(7)(a)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)1.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)10.	General Compliance Testing.	Boiler No. 4 is not exempt from permitting, insignificant, or permitted under the general Permit provisions.
NON-APPLICABLE	62-297	62-297.310(7)(a)2.	General Compliance Testing.	Boiler No. 4 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-297	62-297.310(7)(a)3.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.a.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.b.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)4.c.	General Compliance Testing.	No applicable standard for any NESHAP pollutant.
APPLICABLE	62-297	62-297.310(7)(a)5.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)6.	General Compliance Testing.	Boiler No. 4 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-297	62-297.310(7)(a)7.	General Compliance Testing.	Boiler No. 4 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-297	62-297.310(7)(a)8.	General Compliance Testing.	Boiler No. 4 is not a combustion turbine.
APPLICABLE	62-297	62-297.310(7)(a)9.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(b)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(c)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(8)	Test Reports.	
APPLICABLE	62-297	62-297.400	EPA Methods Adopted by Reference.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(25)(a)	EPA Method 25A - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	

EU ID 003 : Sugar Mill Boiler No. 4 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	
NON-APPLICABLE	62-297	62-297.401(9)(a)	EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources - 40 CFR 60	Required method is DEP Test Method 9.
NON-APPLICABLE	62-297	62-297.401(9)(b)	EPA Test Method 9	Required method is DEP Test Method 9.
APPLICABLE	62-297	62-297.401(9)(c)	DEP Test Method 9	
APPLICABLE	62-297	62-297.440	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(b)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(h)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(i)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.620	Exceptions and Approval of Alternate Procedures and Requirements.	

only.

Appendix R-1, Applicable / Non-Applicable Rules has been added at the applicants request through Golder Associates, Inc. and is included for information purposes o
It does not imply the endorsement of the list by the Department.

EU ID 004 : Sugar Mill Boiler No. 5 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
NON-APPLICABLE	60 Subpart A	40CFR60.1	Subpart A -- General Provisions	Boiler No. 5 is not subject to NSPS.
NON-APPLICABLE	60 Subpart D	40CFR60.40	SubPart D -- Applicability and designation of affected facility	Boiler No. 5 was constructed prior to August 17, 1971, and has not been modified or reconstructed after this date.
NON-APPLICABLE	60 Subpart Db	40CFR60.40b	Subpart Db -- Applicability and delegation of authority	Boiler No. 5 was constructed prior to June 19, 1984, and has not been modified or reconstructed after this date.
NON-APPLICABLE	60 Subpart Dc	40CFR60.40c	Subpart Dc -- Small Industrial - Commercial - Institutional Steam Generating Units -- Applicability	Boiler No. 5 was constructed prior to June 9, 1989, and has not been modified or reconstructed after this date. In addition, Boiler No. 5 has a heat input of greater than 100 MMBtu/hr.
APPLICABLE	62-210	62-210	STATIONARY SOURCES - GENERAL REQUIREMENTS	
APPLICABLE	62-210	62-210.700	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(1)	EXCESS EMISSIONS	
NON-APPLICABLE	62-210	62-210.700(2)	EXCESS EMISSIONS	Boiler No. 5 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-210	62-210.700(3)	EXCESS EMISSIONS	Boiler No. 5 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-210	62-210.700(4)	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(5)	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(6)	EXCESS EMISSIONS	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
NON-APPLICABLE	62-296 <	62-296.320(4)(b)	General Pollutant Emission Limiting Standards.	A visible emission standard set forth elsewhere in Rule 62-296 applies to Boiler No. 5.
NON-APPLICABLE	62-296 <	62-296.405	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	Boiler No. 5 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Boiler No. 5 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	
APPLICABLE	62-296 <	62-296.410(1)	Carbonaceous Fuel Burning Equipment.	
NON-APPLICABLE	62-296 <	62-296.410(1)(a)	Carbonaceous Fuel Burning Equipment.	Boiler No. 5 has a maximum heat input capacity of greater than 30 MMBtu/hr.
APPLICABLE	62-296 <	62-296.410(1)(b)	Carbonaceous Fuel Burning Equipment.	
NON-APPLICABLE	62-296 <	62-296.410(2)	New Emissions Units.	Boiler No. 5 was issued a permit prior to July 1, 1974.
APPLICABLE	62-296 <	62-296.410(3)	Test Methods and Procedures.	
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facili	
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)		
NON-APPLICABLE	62-296 >	62-296.570(1)(b)		Boiler No. 5 is not exempt from permiitting.
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)1.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)2.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)3.	Operation Permit Requirements.	
NON-APPLICABLE	62-296 >	62-296.570(4)(a)4.	Operation Permit Requirements.	Boiler No. 5 does not have a CEMS.
APPLICABLE	62-296 >	62-296.570(4)(b)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.

EU ID 004 : Sugar Mill Boiler No. 5 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	**62-297**	**62-297**	**STATIONARY SOURCES - EMISSIONS MONITORING**	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.310(1)	Required Number of Test Runs.	
APPLICABLE	62-297	62-297.310(2)	Operating Rate During Testing.	
NON-APPLICABLE	62-297	62-297.310(2)(a)	Operating Rate During Testing.	Boiler No. 5 is not a combustion turbine.
APPLICABLE	62-297	62-297.310(2)(b)	Operating Rate During Testing.	
APPLICABLE	62-297	62-297.310(3)	Calculation of Emission Rate.	
APPLICABLE	62-297	62-297.310(4)	Applicable Test Procedures.	
APPLICABLE	62-297	62-297.310(5)	Determination of Process Variables.	
APPLICABLE	62-297	62-297.310(6)	Required Stack Sampling Facilities.	
APPLICABLE	62-297	62-297.310(7)	Frequency of Compliance Tests.	
APPLICABLE	62-297	62-297.310(7)(a)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)1.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)10.	General Compliance Testing.	Boiler No. 5 is not exempt from permitting, insignificant, or permitted under the general Permit provisions.
NON-APPLICABLE	62-297	62-297.310(7)(a)2.	General Compliance Testing.	Boiler No. 5 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-297	62-297.310(7)(a)3.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.a.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.b.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)4.c.	General Compliance Testing.	No applicable standard for any NESHAP pollutant.
APPLICABLE	62-297	62-297.310(7)(a)5.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)6.	General Compliance Testing.	Boiler No. 5 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-297	62-297.310(7)(a)7.	General Compliance Testing.	Boiler No. 5 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-297	62-297.310(7)(a)8.	General Compliance Testing.	Boiler No. 5 is not a combustion turbine.
APPLICABLE	62-297	62-297.310(7)(a)9.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(b)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(c)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(8)	Test Reports.	
APPLICABLE	62-297	62-297.400	EPA Methods Adopted by Reference.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(25)(a)	EPA Method 25A - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	

EU ID 004 : Sugar Mill Boiler No. 5 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	
NON-APPLICABLE	62-297	62-297.401(9)(a)	EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources - 40 CFR 60	Required method is DEP Test Method 9.
NON-APPLICABLE	62-297	62-297.401(9)(b)	EPA Test Method 9	Required method is DEP Test Method 9.
APPLICABLE	62-297	62-297.401(9)(c)	DEP Test Method 9	
APPLICABLE	62-297	62-297.440	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(b)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(h)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(i)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.620	Exceptions and Approval of Alternate Procedures and Requirements.	

only.

Appendix R-1, Applicable / Non-Applicable Rules has been added at the applicants request through Golder Associates, Inc. and is included for information purposes o
It does not imply the endorsement of the list by the Department.

EU ID 005 : Sugar Mill Boiler No. 6 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
NON-APPLICABLE	60 Subpart A	40CFR60.1	Subpart A -- General Provisions	Boiler No. 6 is not subject to NSPS.
NON-APPLICABLE	60 Subpart D	40CFR60.40	SubPart D -- Applicability and designation of affected facility	Boiler No. 6 was constructed prior to August 17, 1971, and has not been modified or reconstructed after this date.
NON-APPLICABLE	60 Subpart Db	40CFR60.40b	Subpart Db -- Applicability and delegation of authority	Boiler No. 6 was constructed prior to June 19, 1984, and has not been modified or reconstructed after this date.
NON-APPLICABLE	60 Subpart Dc	40CFR60.40c	Subpart Dc -- Small Industrial - Commercial - Institutional Steam Generating Units -- Applicability	Boiler No. 6 was constructed prior to June 9, 1989, and has not been modified or reconstructed after this date. In addition, Boiler No. 6 has a heat input of greater than 100 MMBtu/hr.
APPLICABLE	62-210	62-210	STATIONARY SOURCES - GENERAL REQUIREMENTS	
APPLICABLE	62-210	62-210.700	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(1)	EXCESS EMISSIONS	
NON-APPLICABLE	62-210	62-210.700(2)	EXCESS EMISSIONS	Boiler No. 6 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-210	62-210.700(3)	EXCESS EMISSIONS	Boiler No. 6 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-210	62-210.700(4)	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(5)	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(6)	EXCESS EMISSIONS	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
NON-APPLICABLE	62-296 <	62-296.320(4)(b)	General Pollutant Emission Limiting Standards.	A visible emission standard set forth elsewhere in Rule 62-296 applies to Boiler No. 6.
NON-APPLICABLE	62-296 <	62-296.405	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	Boiler No. 6 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Boiler No. 6 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	
APPLICABLE	62-296 <	62-296.410(1)	Carbonaceous Fuel Burning Equipment.	
NON-APPLICABLE	62-296 <	62-296.410(1)(a)	Carbonaceous Fuel Burning Equipment.	Boiler No. 6 has a maximum heat input capacity of greater than 30 MMBtu/hr.
APPLICABLE	62-296 <	62-296.410(1)(b)	Carbonaceous Fuel Burning Equipment.	
NON-APPLICABLE	62-296 <	62-296.410(2)	New Emissions Units.	Boiler No. 6 was issued a permit prior to July 1, 1974.
APPLICABLE	62-296 <	62-296.410(3)	Test Methods and Procedures.	
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facili	
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)		
NON-APPLICABLE	62-296 >	62-296.570(1)(b)		Boiler No. 6 is not exempt from permiitting.
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)1.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)2.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)3.	Operation Permit Requirements.	
NON-APPLICABLE	62-296 >	62-296.570(4)(a)4.	Operation Permit Requirements.	Boiler No. 6 does not have a CEMS.
APPLICABLE	62-296 >	62-296.570(4)(b)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.

EU ID 005 : Sugar Mill Boiler No. 6 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	**62-297**	**62-297**	**STATIONARY SOURCES - EMISSIONS MONITORING**	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.310(1)	Required Number of Test Runs.	
APPLICABLE	62-297	62-297.310(2)	Operating Rate During Testing.	
NON-APPLICABLE	62-297	62-297.310(2)(a)	Operating Rate During Testing.	Boiler No. 6 is not a combustion turbine.
APPLICABLE	62-297	62-297.310(2)(b)	Operating Rate During Testing.	
APPLICABLE	62-297	62-297.310(3)	Calculation of Emission Rate.	
APPLICABLE	62-297	62-297.310(4)	Applicable Test Procedures.	
APPLICABLE	62-297	62-297.310(5)	Determination of Process Variables.	
APPLICABLE	62-297	62-297.310(6)	Required Stack Sampling Facilities.	
APPLICABLE	62-297	62-297.310(7)	Frequency of Compliance Tests.	
APPLICABLE	62-297	62-297.310(7)(a)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)1.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)10.	General Compliance Testing.	Boiler No. 6 is not exempt from permitting, insignificant, or permitted under the general Permit provisions.
NON-APPLICABLE	62-297	62-297.310(7)(a)2.	General Compliance Testing.	Boiler No. 6 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-297	62-297.310(7)(a)3.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.a.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.b.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)4.c.	General Compliance Testing.	No applicable standard for any NESHAP pollutant.
APPLICABLE	62-297	62-297.310(7)(a)5.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)6.	General Compliance Testing.	Boiler No. 6 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-297	62-297.310(7)(a)7.	General Compliance Testing.	Boiler No. 6 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-297	62-297.310(7)(a)8.	General Compliance Testing.	Boiler No. 6 is not a combustion turbine.
APPLICABLE	62-297	62-297.310(7)(a)9.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(b)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(c)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(8)	Test Reports.	
APPLICABLE	62-297	62-297.400	EPA Methods Adopted by Reference.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(25)(a)	EPA Method 25A - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	

EU ID 005 : Sugar Mill Boiler No. 6 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	
NON-APPLICABLE	62-297	62-297.401(9)(a)	EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources - 40 CFR 60	Required method is DEP Test Method 9.
NON-APPLICABLE	62-297	62-297.401(9)(b)	EPA Test Method 9	Required method is DEP Test Method 9.
APPLICABLE	62-297	62-297.401(9)(c)	DEP Test Method 9	
APPLICABLE	62-297	62-297.440	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(b)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(h)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(i)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.620	Exceptions and Approval of Alternate Procedures and Requirements.	

only.

Appendix R-1, Applicable / Non-Applicable Rules has been added at the applicants request through Golder Associates, Inc. and is included for information purposes o
It does not imply the endorsement of the list by the Department.

EU ID 009 : Sugar Mill Boiler No. 10 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
NON-APPLICABLE	60 Subpart A	40CFR60.1	Subpart A -- General Provisions	Boiler No. 10 is not subject to NSPS.
NON-APPLICABLE	60 Subpart D	40CFR60.40	SubPart D -- Applicability and designation of affected facility	Boiler No. 10 was constructed prior to August 17, 1971, and has not been modified or reconstructed after this date.
NON-APPLICABLE	60 Subpart Db	40CFR60.40b	Subpart Db -- Applicability and delegation of authority	Boiler No. 10 was constructed prior to June 19, 1984, and has not been modified or reconstructed after this date.
NON-APPLICABLE	60 Subpart Dc	40CFR60.40c	Subpart Dc -- Small Industrial - Commercial - Institutional Steam Generating Units -- Applicability	Boiler No. 10 was constructed prior to June 9, 1989, and has not been modified or reconstructed after this date. In addition, Boiler No. 10 has a heat input of greater than 100 MMBtu/hr.
APPLICABLE	62-210	62-210	STATIONARY SOURCES - GENERAL REQUIREMENTS	
APPLICABLE	62-210	62-210.700	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(1)	EXCESS EMISSIONS	
NON-APPLICABLE	62-210	62-210.700(2)	EXCESS EMISSIONS	Boiler No. 10 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-210	62-210.700(3)	EXCESS EMISSIONS	Boiler No. 10 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-210	62-210.700(4)	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(5)	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(6)	EXCESS EMISSIONS	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
NON-APPLICABLE	62-296 <	62-296.320(4)(b)	General Pollutant Emission Limiting Standards.	A visible emission standard set forth elsewhere in Rule 62-296 applies to Boiler No. 10.
NON-APPLICABLE	62-296 <	62-296.405	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	Boiler No. 10 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Boiler No. 10 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	
APPLICABLE	62-296 <	62-296.410(1)	Carbonaceous Fuel Burning Equipment.	
NON-APPLICABLE	62-296 <	62-296.410(1)(a)	Carbonaceous Fuel Burning Equipment.	Boiler No. 10 has a maximum heat input capacity of greater than 30 MMBtu/hr.
APPLICABLE	62-296 <	62-296.410(1)(b)	Carbonaceous Fuel Burning Equipment.	
NON-APPLICABLE	62-296 <	62-296.410(2)	New Emissions Units.	Boiler No. 10 was issued a permit prior to July 1, 1974.
APPLICABLE	62-296 <	62-296.410(3)	Test Methods and Procedures.	
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facili	
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)		
NON-APPLICABLE	62-296 >	62-296.570(1)(b)		Boiler No. 10 is not exempt from permiitting.
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)1.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)2.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)3.	Operation Permit Requirements.	
NON-APPLICABLE	62-296 >	62-296.570(4)(a)4.	Operation Permit Requirements.	Boiler No. 10 does not have a CEMS.
APPLICABLE	62-296 >	62-296.570(4)(b)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.

EU ID 009 : Sugar Mill Boiler No. 10 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	**62-297**	**62-297**	**STATIONARY SOURCES - EMISSIONS MONITORING**	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.310(1)	Required Number of Test Runs.	
APPLICABLE	62-297	62-297.310(2)	Operating Rate During Testing.	
NON-APPLICABLE	62-297	62-297.310(2)(a)	Operating Rate During Testing.	Boiler No. 10 is not a combustion turbine.
APPLICABLE	62-297	62-297.310(2)(b)	Operating Rate During Testing.	
APPLICABLE	62-297	62-297.310(3)	Calculation of Emission Rate.	
APPLICABLE	62-297	62-297.310(4)	Applicable Test Procedures.	
APPLICABLE	62-297	62-297.310(5)	Determination of Process Variables.	
APPLICABLE	62-297	62-297.310(6)	Required Stack Sampling Facilities.	
APPLICABLE	62-297	62-297.310(7)	Frequency of Compliance Tests.	
APPLICABLE	62-297	62-297.310(7)(a)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)1.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)10.	General Compliance Testing.	Boiler No. 10 is not exempt from permitting, insignificant, or permitted under the general Permit provisions.
NON-APPLICABLE	62-297	62-297.310(7)(a)2.	General Compliance Testing.	Boiler No. 10 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-297	62-297.310(7)(a)3.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.a.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.b.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)4.c.	General Compliance Testing.	No applicable standard for any NESHAP pollutant.
APPLICABLE	62-297	62-297.310(7)(a)5.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)6.	General Compliance Testing.	Boiler No. 10 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-297	62-297.310(7)(a)7.	General Compliance Testing.	Boiler No. 10 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-297	62-297.310(7)(a)8.	General Compliance Testing.	Boiler No. 10 is not a combustion turbine.
APPLICABLE	62-297	62-297.310(7)(a)9.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(b)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(c)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(8)	Test Reports.	
APPLICABLE	62-297	62-297.400	EPA Methods Adopted by Reference.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(25)(a)	EPA Method 25A - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	

EU ID 009 : Sugar Mill Boiler No. 10 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	
NON-APPLICABLE	62-297	62-297.401(9)(a)	EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources - 40 CFR 60	Required method is DEP Test Method 9.
NON-APPLICABLE	62-297	62-297.401(9)(b)	EPA Test Method 9	Required method is DEP Test Method 9.
APPLICABLE	62-297	62-297.401(9)(c)	DEP Test Method 9	
APPLICABLE	62-297	62-297.440	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(b)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(h)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(i)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.620	Exceptions and Approval of Alternate Procedures and Requirements.	

only.

Appendix R-1, Applicable / Non-Applicable Rules has been added at the applicants request through Golder Associates, Inc. and is included for information purposes o
It does not imply the endorsement of the list by the Department.

EU ID 010 : Sugar Mill Boiler No. 11 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
NON-APPLICABLE	60 Subpart A	40CFR60.1	Subpart A -- General Provisions	Boiler No. 11 is not subject to NSPS.
NON-APPLICABLE	60 Subpart D	40CFR60.40	SubPart D -- Applicability and designation of affected facility	Boiler No. 11 does not combust fossil fuel at greater than 250 MMBtu/hr.
NON-APPLICABLE	60 Subpart Db	40CFR60.40b	Subpart Db -- Applicability and delegation of authority	Boiler No. 11 was constructed prior to June 19, 1984, and has not been modified or reconstructed after this date.
NON-APPLICABLE	60 Subpart Dc	40CFR60.40c	Subpart Dc -- Small Industrial - Commercial - Institutional Steam Generating Units -- Applicability	Boiler No. 11 was constructed prior to June 9, 1989, and has not been modified or reconstructed after this date. In addition, Boiler No. 11 has a heat input of greater than 100 MMBtu/hr.
APPLICABLE	62-210	62-210	STATIONARY SOURCES - GENERAL REQUIREMENTS	
APPLICABLE	62-210	62-210.700	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(1)	EXCESS EMISSIONS	
NON-APPLICABLE	62-210	62-210.700(2)	EXCESS EMISSIONS	Boiler No. 11 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-210	62-210.700(3)	EXCESS EMISSIONS	Boiler No. 11 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-210	62-210.700(4)	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(5)	EXCESS EMISSIONS	
APPLICABLE	62-210	62-210.700(6)	EXCESS EMISSIONS	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
NON-APPLICABLE	62-296 <	62-296.320(4)(b)	General Pollutant Emission Limiting Standards.	A visible emission standard set forth elsewhere in Rule 62-296 applies to Boiler No. 11.
NON-APPLICABLE	62-296 <	62-296.405	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	Boiler No. 11 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Boiler No. 11 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	
NON-APPLICABLE	62-296 <	62-296.410(1)	Carbonaceous Fuel Burning Equipment.	Boiler No. 11 was issued a permit after July 1, 1974.
APPLICABLE	62-296 <	62-296.410(2)	New Emissions Units.	
NON-APPLICABLE	62-296 <	62-296.410(2)(a)	Carbonaceous Fuel Burning Equipment.	Boiler No. 11 has a maximum heat input capacity of greater than 30 MMBtu/hr.
APPLICABLE	62-296 <	62-296.410(2)(b)	Carbonaceous Fuel Burning Equipment.	
APPLICABLE	62-296 <	62-296.410(3)	Test Methods and Procedures.	
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facili	
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)		
NON-APPLICABLE	62-296 >	62-296.570(1)(b)		Boiler No. 11 is not exempt from permiitting.
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)1.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)2.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)3.	Operation Permit Requirements.	
NON-APPLICABLE	62-296 >	62-296.570(4)(a)4.	Operation Permit Requirements.	Boiler No. 11 does not have a CEMS.
APPLICABLE	62-296 >	62-296.570(4)(b)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.

EU ID 010 : Sugar Mill Boiler No. 11 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	Okeelanta Corporation is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	**62-297**	**62-297**	**STATIONARY SOURCES - EMISSIONS MONITORING**	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.310(1)	Required Number of Test Runs.	
APPLICABLE	62-297	62-297.310(2)	Operating Rate During Testing.	
NON-APPLICABLE	62-297	62-297.310(2)(a)	Operating Rate During Testing.	Boiler No. 11 is not a combustion turbine.
APPLICABLE	62-297	62-297.310(2)(b)	Operating Rate During Testing.	
APPLICABLE	62-297	62-297.310(3)	Calculation of Emission Rate.	
APPLICABLE	62-297	62-297.310(4)	Applicable Test Procedures.	
APPLICABLE	62-297	62-297.310(5)	Determination of Process Variables.	
APPLICABLE	62-297	62-297.310(6)	Required Stack Sampling Facilities.	
APPLICABLE	62-297	62-297.310(7)	Frequency of Compliance Tests.	
APPLICABLE	62-297	62-297.310(7)(a)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)1.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)10.	General Compliance Testing.	Boiler No. 11 is not exempt from permitting, insignificant, or permitted under the general Permit provisions.
NON-APPLICABLE	62-297	62-297.310(7)(a)2.	General Compliance Testing.	Boiler No. 11 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
APPLICABLE	62-297	62-297.310(7)(a)3.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.a.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(a)4.b.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)4.c.	General Compliance Testing.	No applicable standard for any NESHAP pollutant.
APPLICABLE	62-297	62-297.310(7)(a)5.	General Compliance Testing.	
NON-APPLICABLE	62-297	62-297.310(7)(a)6.	General Compliance Testing.	Boiler No. 11 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-297	62-297.310(7)(a)7.	General Compliance Testing.	Boiler No. 11 is defined as a carbonaceous fuel-fired boiler, not a fossil fuel steam generator.
NON-APPLICABLE	62-297	62-297.310(7)(a)8.	General Compliance Testing.	Boiler No. 11 is not a combustion turbine.
APPLICABLE	62-297	62-297.310(7)(a)9.	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(b)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(7)(c)	General Compliance Testing.	
APPLICABLE	62-297	62-297.310(8)	Test Reports.	
APPLICABLE	62-297	62-297.400	EPA Methods Adopted by Reference.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(25)(a)	EPA Method 25A - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	

EU ID 010 : Sugar Mill Boiler No. 11 Rule Applicability, Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONAL FOR NON-APPLICABILITY
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendix	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	
NON-APPLICABLE	62-297	62-297.401(9)(a)	EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources - 40 CFR 60	Required method is DEP Test Method 9.
NON-APPLICABLE	62-297	62-297.401(9)(b)	EPA Test Method 9	Required method is DEP Test Method 9.
APPLICABLE	62-297	62-297.401(9)(c)	DEP Test Method 9	
APPLICABLE	62-297	62-297.440	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(b)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(h)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.440(1)(i)	Supplementary Test Procedures.	
APPLICABLE	62-297	62-297.620	Exceptions and Approval of Alternate Procedures and Requirements.	

only.

Appendix R-1, Applicable / Non-Applicable Rules has been added at the applicants request through Golder Associates, Inc. and is included for information purposes only.
It does not imply the endorsement of the list by the Department.

EU ID 014 : Mill Boiler No. 16 Rule Applicability for Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart A	40CFR60.1	Subpart A -- General Provisions	
APPLICABLE	60 Subpart A	40CFR60.7	Notification and Record Keeping	
APPLICABLE	60Subpart A	40CFR60.8	Performance Testing	
APPLICABLE	60 Subpart A	40CFR60.11	Compliance with standards and maintenance requirements.	
APPLICABLE	60 Subpart A	40CFR60.12	Circumvention.	
APPLICABLE	60 Subpart A	40CFR60.13	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.13(a)	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.13(b)	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.13(c)	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.13(d)(1)	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.13(d)(2)	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.13(e)	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.13(f)	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.13(h)	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.13(i)	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.13(j)	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.19	General notification and reporting requirements	
NON-APPLICABLE	60 Subpart Da	40CFR60.40a	Subpart Da - NSPS for Electric Utility Units for which construction commenced after Sept. 18, 1978.	Boiler No. 16 is not an electric utility unit.
APPLICABLE	60 Subpart Db	40CFR60.40b	Subpart DB -- Applicability and delegation of authority	
APPLICABLE	60 Subpart Db	40CFR60.40b(a)		
APPLICABLE	60 Subpart Db	40CFR60.42b	Standard for sulfur dioxide	
APPLICABLE	60 Subpart Db	40CFR60.42b(a)		
NON-APPLICABLE	60 Subpart Db	40CFR60.42b(c)		
NON-APPLICABLE	60 Subpart Db	40CFR60.42b(d)		
APPLICABLE	60 Subpart Db	40CFR60.42b(e)		
NON-APPLICABLE	60 Subpart Db	40CFR60.42b(f)		
APPLICABLE	60 Subpart Db	40CFR60.42b(g)		
APPLICABLE	60 Subpart Db	40CFR60.42b(j)		
APPLICABLE	60 Subpart Db	40CFR60.43b	Standard for particulate matter	
NON-APPLICABLE	60 Subpart Db	40CFR60.43b(b)		
APPLICABLE	60 Subpart Db	40CFR60.43b(f)		
APPLICABLE	60 Subpart Db	40CFR60.43b(g)		
APPLICABLE	60 Subpart Db	40CFR60.44b	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Db	40CFR60.44b(a)		
APPLICABLE	60 Subpart Db	40CFR60.44b(h)		
APPLICABLE	60 Subpart Db	40CFR60.44b(i)		
NON-APPLICABLE	60 Subpart Db	40CFR60.44b(j)		
NON-APPLICABLE	60 Subpart Db	40CFR60.44b(l)		
APPLICABLE	60 Subpart Db	40CFR60.45b		
APPLICABLE	60 Subpart Db	40CFR60.45b(a)		
APPLICABLE	60 Subpart Db	40CFR60.45b(j)		
APPLICABLE	60 Subpart Db	40CFR60.46b		
APPLICABLE	60 Subpart Db	40CFR60.46b(a)		
APPLICABLE	60 Subpart Db	40CFR60.46b(c)		
APPLICABLE	60 Subpart Db	40CFR60.46b(d)		
APPLICABLE	60 Subpart Db	40CFR60.46b(d)(7)		
APPLICABLE	60 Subpart Db	40CFR60.46b(e)		
APPLICABLE	60 Subpart Db	40CFR60.46b(e)(1)		
NON-APPLICABLE	60 Subpart Db	40CFR60.46b(e)(3)		
APPLICABLE	60 Subpart Db	40CFR60.46b(e)(4)		
APPLICABLE	60 Subpart Db	40CFR60.47b	Emission monitoring for sulfur dioxide	
APPLICABLE	60 Subpart Db	40CFR60.47b(f)		
APPLICABLE	60 Subpart Db	40CFR60.48b	Emission monitoring for particulate matter and nitrogen oxides	
APPLICABLE	60 Subpart Db	40CFR60.48b(a)		
APPLICABLE	60 Subpart Db	40CFR60.48b(b)		
APPLICABLE	60 Subpart Db	40CFR60.48b(c)		
APPLICABLE	60 Subpart Db	40CFR60.48b(d)		
APPLICABLE	60 Subpart Db	40CFR60.48b(e)		
APPLICABLE	60 Subpart Db	40CFR60.48b(e)(2)		
APPLICABLE	60 Subpart Db	40CFR60.48b(e)(3)		
APPLICABLE	60 Subpart Db	40CFR60.48b(f)		

EU ID 014 : Mill Boiler No. 16 Rule Applicability for Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart Db	40CFR60.48b(g)		
APPLICABLE	60 Subpart Db	40CFR60.48b(g)(1)		
NON-APPLICABLE	60 Subpart Db	40CFR60.48b(g)(2)		
NON-APPLICABLE	60 Subpart Db	40CFR60.48b(i)		
APPLICABLE	60 Subpart Db	40CFR60.49b	Reporting and recordkeeping requirements	
APPLICABLE	60 Subpart Db	40CFR60.49b(a)		
APPLICABLE	60 Subpart Db	40CFR60.49b(b)		
NON-APPLICABLE	60 Subpart Db	40CFR60.49b(c)		
APPLICABLE	60 Subpart Db	40CFR60.49b(c)(1)		
APPLICABLE	60 Subpart Db	40CFR60.49b(d)		
APPLICABLE	60 Subpart Db	40CFR60.49b(f)		
APPLICABLE	60 Subpart Db	40CFR60.49b(g)		
APPLICABLE	60 Subpart Db	40CFR60.49b(h)		
APPLICABLE	60 Subpart Db	40CFR60.49b(i)		
APPLICABLE	60 Subpart Db	40CFR60.49b(j)		
NON-APPLICABLE	60 Subpart Db	40CFR60.49b(k)		
NON-APPLICABLE	60 Subpart Db	40CFR60.49b(l)		
APPLICABLE	60 Subpart Db	40CFR60.49b(o)		
APPLICABLE	60 Subpart Db	40CFR60.49b(r)		
APPLICABLE	60 Subpart Db	40CFR60.49b(s)		
APPLICABLE	60 Subpart Db	40CFR60.49b(v)		
APPLICABLE	62-204	62-204.800(7)3	NSPS Subpart Db adopted by reference.	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
NON-APPLICABLE	62-296 <	62-296.405	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	Cogen Boiler No. 16 has a heat input of <250 MMBtu/hr.
APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	
NON-APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	Boiler No. 16 was subject to PSD/BACT for NOx emissions.
NON-APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facili	Boiler No. 16 was subject to PSD/BACT for NOx emissions.
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	Okeelanta is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	Okeelanta is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	62-297	62-297	STATIONARY SOURCES - EMISSIONS MONITORING	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.310(1)	Required Number of Test Runs.	
APPLICABLE	62-297	62-297.310(2)	Operating Rate During Testing.	
APPLICABLE	62-297	62-297.310(3)	Calculation of Emission Rate.	
APPLICABLE	62-297	62-297.310(4)	Applicable Test Procedures.	
APPLICABLE	62-297	62-297.310(5)	Determination of Process Variables.	
APPLICABLE	62-297	62-297.310(6)	Required Stack Sampling Facilities.	
APPLICABLE	62-297	62-297.310(7)	Frequency of Compliance Tests.	
APPLICABLE	62-297	62-297.310(8)	Test Reports.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(10)	EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources - 40 CFR 60 Appen	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	

EU ID 014 : Mill Boiler No. 16 Rule Applicability for Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(41)	EPA Method 201 - Determination of PM10 Emissions (Exhaust Gas Recycle Procedure) - 40 CFR 51 Appendi	
APPLICABLE	62-297	62-297.401(41)(a)	EPA Method 201A - Determination of PM10 Emissions (Exhaust Gas Recycle Procedure) - 40 CFR 51 Appendi	
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)(a)	EPA Method 7A - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	
	62-297	62-297.620	Exceptions and Approval of Alternate Procedures and Requirements.	

Appendix R-1, Applicable / Non-Applicable Rules has been added at the applicants request through Golder Associates, Inc. and is included for information purposes only. It does not imply the endorsement of the list by the Department.

EU ID 030 : Cogen Boiler No. 1 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart A	40CFR60.1	Subpart A -- General Provisions	
APPLICABLE	60 Subpart A	40CFR60.7	Notification and Record Keeping	
APPLICABLE	60Subpart A	40CFR60.8	Performance Testing	
APPLICABLE	60 Subpart A	40CFR60.11	Compliance with standards and maintenance requirements.	
APPLICABLE	60 Subpart A	40CFR60.12	Circumvention.	
APPLICABLE	60 Subpart A	40CFR60.13	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.19	General notification and reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.40a	Subpart Da - NSPS for Electric Utility Units for which construction commenced after Sept. 18, 1978.	
APPLICABLE	60 Subpart Da	40CFR60.42a	Standard for particulate matter	
APPLICABLE	60 Subpart Da	40CFR60.43a	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(a)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(b)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(d)(2)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(g)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(h)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.44a	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(a)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(c)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.46a	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(a)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(b)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(c)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(d)	Compliance provisions.	Cogen Boiler No. 1 does not have a flue gas desulfurization system.
APPLICABLE	60 Subpart Da	40CFR60.46a(e)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(f)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(g)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(h)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(i)	Compliance provisions.	Cogen Boiler No. 1 has not been modified after July 7, 1997.
APPLICABLE	60 Subpart Da	40CFR60.47a	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(a)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(2)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(3)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(c)(1)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(d)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(e)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(f)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(g)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(h)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(i)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(j)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.48a	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(a)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(b)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(c)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(d)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(e)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.49a	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(a)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(b)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(c)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(d)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(f)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(g)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(h)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(i)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(j)	Reporting requirements	
APPLICABLE	60 Subpart Ea	40CFR60.50a(d)	Standards of performance for municipal waste combustors	
APPLICABLE	60 Subpart Ea	40CFR60.50b(j)	Standards of performance for municipal waste combustors	
APPLICABLE	62-204	62-204.800(7)2.	NSPS Subpart Da adopted by reference.	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
APPLICABLE	62-296 <	62-296.405(2)	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Cogen Boiler No. 1 has a heat input of >250 MMBtu/hr.
NON-APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	Not more stringent or different than NSPS.
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(a)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(c)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facili	

EU ID 030 : Cogen Boiler No. 1 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)	Applicability.	
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.620		
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	62-297	62-297	STATIONARY SOURCES - EMISSIONS MONITORING	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(10)	EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources - 40 CFR 60 Appen	
APPLICABLE	62-297	62-297.401(12)	EPA Method 12 - Determination of Inorganic Lead Emissions from Stationary Sources - 40 CFR 60 Append	
APPLICABLE	62-297	62-297.401(13)	EPA Methods 13A and 13B.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(19)	EPA Method 19 - Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide a	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(32)	EPA Method 101 - Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants	
APPLICABLE	62-297	62-297.401(35)	EPA Method 104 - Determination of Beryllium Emissions from Stationary Sources - 40 CFR 61 Appendix B	
APPLICABLE	62-297	62-297.401(39)	EPA Method 108 - Determination of Particulate and Gaseous Arsenic Emissions - 40 CFR 61 Appendix B.	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(41)	EPA Method 201 - Determination of PM10 Emissions (Exhaust Gas Recycle Procedure) - 40 CFR 51 Appendi	
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(6)	EPA Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(6)(c)	EPA Method 6C - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(8)	EPA Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sour	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	

Appendix R-1, Applicable / Non-Applicable Rules has been added at the applicants request through Golder Associates, Inc. and is included for information purposes only. It does not imply the endorsement of the list by the Department.

EU ID 031 : Cogen Boiler No. 2 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart A	40CFR60.1	Subpart A -- General Provisions	
APPLICABLE	60 Subpart A	40CFR60.7	Notification and Record Keeping	
APPLICABLE	60Subpart A	40CFR60.8	Performance Testing	
APPLICABLE	60 Subpart A	40CFR60.11	Compliance with standards and maintenance requirements.	
APPLICABLE	60 Subpart A	40CFR60.12	Circumvention.	
APPLICABLE	60 Subpart A	40CFR60.13	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.19	General notification and reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.40a	Subpart Da - NSPS for Electric Utility Units for which construction commenced after Sept. 18, 1978.	
APPLICABLE	60 Subpart Da	40CFR60.42a	Standard for particulate matter	
APPLICABLE	60 Subpart Da	40CFR60.43a	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(a)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(b)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(d)(2)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(g)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(h)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.44a	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(a)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(c)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.46a	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(a)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(b)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(c)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(d)	Compliance provisions.	Cogen Boiler No. 2 does not have a flue gas desulfurization system.
APPLICABLE	60 Subpart Da	40CFR60.46a(e)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(f)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(g)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(h)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(i)	Compliance provisions.	Cogen Boiler No. 2 has not been modified after July 7, 1997.
APPLICABLE	60 Subpart Da	40CFR60.47a	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(a)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(2)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(3)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(c)(1)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(d)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(e)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(f)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(g)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(h)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(i)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(j)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.48a	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(a)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(b)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(c)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(d)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(e)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.49a	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(a)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(b)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(c)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(d)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(f)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(g)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(h)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(i)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(j)	Reporting requirements	
APPLICABLE	60 Subpart Ea	40CFR60.50a(d)	Standards of performance for municipal waste combustors	
APPLICABLE	60 Subpart Ea	40CFR60.50b(j)	Standards of performance for municipal waste combustors	
APPLICABLE	62-204	62-204.800(7)2.	NSPS Subpart Da adopted by reference.	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
APPLICABLE	62-296 <	62-296.405(2)	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Cogen Boiler No. 2 has a heat input of >250 MMBtu/hr.
NON-APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	Not more stringent or different than NSPS.
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(a)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(c)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facili	
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)	Applicability.	

EU ID 031 : Cogen Boiler No. 2 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.620		
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	62-297	62-297	STATIONARY SOURCES - EMISSIONS MONITORING	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(10)	EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources - 40 CFR 60 Appen	
APPLICABLE	62-297	62-297.401(12)	EPA Method 12 - Determination of Inorganic Lead Emissions from Stationary Sources - 40 CFR 60 Append	
APPLICABLE	62-297	62-297.401(13)	EPA Methods 13A and 13B.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(19)	EPA Method 19 - Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide a	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(32)	EPA Method 101 - Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants	
APPLICABLE	62-297	62-297.401(35)	EPA Method 104 - Determination of Beryllium Emissions from Stationary Sources - 40 CFR 61 Appendix B	
APPLICABLE	62-297	62-297.401(39)	EPA Method 108 - Determination of Particulate and Gaseous Arsenic Emissions - 40 CFR 61 Appendix B.	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(41)	EPA Method 201 - Determination of PM10 Emissions (Exhaust Gas Recycle Procedure) - 40 CFR 51 Appendi	
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(6)	EPA Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(6)(c)	EPA Method 6C - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(8)	EPA Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sour	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	

Appendix R-1, Applicable / Non-Applicable Rules has been added at the applicants request through Golder Associates, Inc. and is included for information purposes only. It does not imply the endorsement of the list by the Department.

EU ID 032 : Cogen Boiler No. 3 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart A	40CFR60.1	Subpart A -- General Provisions	
APPLICABLE	60 Subpart A	40CFR60.7	Notification and Record Keeping	
APPLICABLE	60Subpart A	40CFR60.8	Performance Testing	
APPLICABLE	60 Subpart A	40CFR60.11	Compliance with standards and maintenance requirements.	
APPLICABLE	60 Subpart A	40CFR60.12	Circumvention.	
APPLICABLE	60 Subpart A	40CFR60.13	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.19	General notification and reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.40a	Subpart Da - NSPS for Electric Utility Units for which construction commenced after Sept. 18, 1978.	
APPLICABLE	60 Subpart Da	40CFR60.42a	Standard for particulate matter	
APPLICABLE	60 Subpart Da	40CFR60.43a	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(a)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(b)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(d)(2)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(g)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(h)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.44a	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(a)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(c)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.46a	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(a)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(b)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(c)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(d)	Compliance provisions.	Cogen Boiler No. 3 does not have a flue gas desulfurization system.
APPLICABLE	60 Subpart Da	40CFR60.46a(e)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(f)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(g)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(h)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(i)	Compliance provisions.	Cogen Boiler No. 3 has not been modified after July 7, 1997.
APPLICABLE	60 Subpart Da	40CFR60.47a	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(a)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(2)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(3)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(c)(1)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(d)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(e)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(f)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(g)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(h)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(i)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(j)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.48a	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(a)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(b)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(c)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(d)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(e)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.49a	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(a)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(b)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(c)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(d)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(f)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(g)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(h)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(i)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(j)	Reporting requirements	
APPLICABLE	60 Subpart Ea	40CFR60.50a(d)	Standards of performance for municipal waste combustors	
APPLICABLE	60 Subpart Ea	40CFR60.50b(j)	Standards of performance for municipal waste combustors	
APPLICABLE	62-204	62-204.800(7)2.	NSPS Subpart Da adopted by reference.	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
APPLICABLE	62-296 <	62-296.405(2)	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Cogen Boiler No. 3 has a heat input of >250 MMBtu/hr.
NON-APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	Not more stringent or different than NSPS.
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(a)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(c)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facili	
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)	Applicability.	

EU ID 032 : Cogen Boiler No. 3 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.620		
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	62-297	62-297	STATIONARY SOURCES - EMISSIONS MONITORING	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(10)	EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources - 40 CFR 60 Appen	
APPLICABLE	62-297	62-297.401(12)	EPA Method 12 - Determination of Inorganic Lead Emissions from Stationary Sources - 40 CFR 60 Append	
APPLICABLE	62-297	62-297.401(13)	EPA Methods 13A and 13B.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(19)	EPA Method 19 - Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide a	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(32)	EPA Method 101 - Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants	
APPLICABLE	62-297	62-297.401(35)	EPA Method 104 - Determination of Beryllium Emissions from Stationary Sources - 40 CFR 61 Appendix B	
APPLICABLE	62-297	62-297.401(39)	EPA Method 108 - Determination of Particulate and Gaseous Arsenic Emissions - 40 CFR 61 Appendix B.	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(41)	EPA Method 201 - Determination of PM10 Emissions (Exhaust Gas Recycle Procedure) - 40 CFR 51 Appendi	
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(6)	EPA Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(6)(c)	EPA Method 6C - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(8)	EPA Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sour	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	

APPENDIX RBL-001
RACT, BACT & LEAR DETERMINATIONS

The following RACT, BACT and LAER determinations are part of the Title V Operating Permit:

Date	Emissions Unit ID No.	Type	Pollutant(s)
07/29/91	14 Mill Boiler No. 16	BACT BACT BACT BACT	Particulate Sulfur Dioxide (fuel oil) Nitrogen Oxides Visible Emissions
9/27/93	30, 31, & 32 Cogen Boilers	BACT BACT BACT	Sulfur Dioxide Fluorides Beryllium
9/27/93	30, 31, & 32 Cogen Boilers	RACT RACT	Nitrogen Oxides Volatile Organic Compounds
10/24/95	30, 31, & 32 Cogen Boilers	Re-BACT Re-BACT Re-BACT	Sulfur Dioxide Fluorides Beryllium
10/24/95	30, 31, & 32 Cogen Boilers	BACT	Nitrogen Oxides
05/21/98	04, 05, 06, 09, 10, 11, 12, & 13 Sugar Mill Boilers	RACT RACT	Nitrogen Oxides Volatile Organic Compounds
01/30/2002	30, 31, & 32 Cogen Boilers	BACT	Carbon Monoxide, Fluorides, Sulfur Dioxide, Sulfuric Acid Mist

APPENDIX SO-1, Simultaneous Operations for the Co-Generation and Sugar Mill Boilers

October 31, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Gus Cepero, Authorized Representative
Okeelanta Power Limited Partnership
P.O. Box 9
South Bay, FL 33493

Re: Project No. 0990332-011-AC
Permit No. PSD-FL-196K
Okeelanta Power L.P. - Cogeneration Plant
Request to Extend Operation of Sugar Mill Boilers as Standby Units

Okeelanta Power L.P. operates a biomass cogeneration plant located near Highway 27, approximately 6 miles south of South Bay in Palm Beach County, Florida. Okeelanta Corporation operates a sugar mill and refinery at an adjacent location. For the purposes of the Department's Prevention of Significant Deterioration (PSD) and Title V operating permit programs, the two plants are considered to be a single facility. Based on the applicant's request, the initial PSD permit required permanent shutdown of the existing sugar mill boilers (except for refinery Boiler No. 16) to offset emissions from the new cogeneration boilers. This federally enforceable permit condition allowed emissions of carbon monoxide, lead, nitrogen oxides, and particulate matter to escape PSD applicability. It also allowed emissions of volatile organic compounds to escape a LAER determination. During the first 12 months of commercial operation, the permit allowed limited simultaneous operation and operation of the sugar mill boilers as standby units if all cogeneration boilers were shutdown. The Department has previously issued several modifications to these conditions related to establishing commercial operation of the cogeneration boilers as well as the ability to provide a reliable source of steam to the sugar mill.

On September 28, 1999, Okeelanta Power L.P. applied to the Department for a modification of Permit No. PSD-FL-196, which would extend the operation of the sugar mill boilers as standby units for the existing sugar mill. The Department has reviewed the modification request, the compliance history, the permitting history, and other additional information provided by Okeelanta Power L.P. The Department approves the request to operate the sugar mill boilers as standby units, but only for electrical or mechanical failure of all three cogeneration boilers. The Department denies the request for any simultaneous operation of the sugar mill boilers (except for refinery Boiler No. 16) with the cogeneration boilers. This modification also includes the addition of mechanical dust collectors that were previously approved by the Department on December 22, 1999. As summarized in the attached Final Determination, only minor changes were made to the Draft Permit. The referenced permit is hereby modified as follows:

Add the following text to the emissions unit description:

"Mechanical dust collectors are installed prior to each electrostatic precipitator to remove large particulate matter."

Revise specific condition No. 5 as follows:

"5. Each boiler shall be equipped with a(n):

- 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);
- Electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter;
- Selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of NOx; and
- Carbon injection system (or equivalent) for mercury emissions control."

Replace specific condition Nos. 17 and 18 with the following revised conditions:

"17. Standby Operation: The sugar mill boilers shall comply with the following requirements as well as Specific Condition No. 18.

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. Sugar Mill Boiler No. 16 shall be retained as a standby boiler for the cogeneration plant and shall operate only when one or more of the cogeneration boilers are shut down, or in the process of immediately shutting down. For each incident of standby use, the permittee shall record the hours of operation and which of the cogeneration boilers was shutdown.

c. 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.

18. Notification of Standby Operation:

a. Within 24 hours of any electrical or mechanical failure that prevents operation of all three cogeneration boilers, the permittee shall notify Department's South District Office and the Palm Beach County Health Department. The notification shall include a description of the problems, the planned corrective actions, and an estimate of the time the cogeneration boilers will be down.

b. Within 24 hours of restarting any sugar mill boiler (other than Boiler No. 16), the permittee shall notify the Department's South District Office and the Palm Beach County Health Department. The notification shall include an estimate of the time the sugar mill boiler will be operated and the corrective actions being taken to restore operation of the cogeneration boilers.

c. For any sugar mill boiler operated or intended to be operated more than 400 hours, the permittee shall schedule and perform all required emissions performance tests. The permittee shall provide at least 48 hours advance notice for any test to the Department's South District Office and the Palm Beach County Health Department.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

_____
Howard L. Rhodes, Director
Division of Air Resources Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this permit modification (including the Final Determination) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on _____ to the person(s) listed:

Mr. Gus Cepero, Okeelanta Power L.P.*
Mr. James Meriwether, Okeelanta Power L.P.
Mr. Ricardo Lima, Okeelanta Corporation
Mr. David Dee, Landers & Parsons
Mr. David Buff, Golder Associates
Mr. James Stormer, PBCHD
Mr. Ray Blackburn, SD
Mr. Gregg Worley, EPA
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.

_____ (Clerk) _____ (Date)

Appendix U-1
List of Unregulated Emission Units and/or Activities

Okeelanta Corporation **Final Permit No.:** 0990005-012-AV
Sugarcane Processing & Power Generation Facilities **Facility ID No.:** 0990005

Unregulated Emissions Units and/or Activities. An emissions unit which emits no "emissions-limited pollutant" and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards.

The below listed emissions units and/or activities have been identified by the permittee as 'unregulated emissions units'.

EU ID No.	EU Description	Activities/Equipment
036	Shop Activities	• Surface Coating Operations (Non-RACT Vehicle Painting) • Diesel Engine – Portable Air Compressor • Vehicle Repair (Body Shop) • Crawlers Repair Shop • Hydraulic Oil, Mineral Spirits, and Waste/Used Oil Storage Tanks • Mechanics' Trucks With Portable Air Compressors (Gasoline Engines) • Portable Pressure Cleaners (Gasoline Engines) • Steam Clean Station • Truck, Trailer, Service Vehicles, Wheel Tractor Repair Shops • Cold Cleaning Devices (parts washer) • Containers for Oil/Grease/Used Oil • Oil/Water Separator/Skimmer Equipment • Portable Welders • Pressurized LPG Tanks • Stationary IC Engines • Vacuum Cleaning Systems • Vehicle Generated Dust • Woodworking and Metal Working Operations
037	Sugar Mill Boiler House	• Boiler Ash Disposal, Handling and Storage • Boiler Blowdown Pipes & Vents • Boiler Water Chemical Prep Tanks • Boiler Water Dearator and Tank
038	Sugar Mill Cane Dumping Area	• Cane Dumping, Handling, and Storage Cane Knives, Shredding, And Conveying • Steam Clean Station • Oil/Water Separator/Skimmer
039	Sugarcane Processing Facility	• Bagacillo Cyclone and Handling Systems • Batch Mixers (<30 Cu. Ft.) • Carbonaceous Fuel Handling, Storage Piles and Hogger • Cold Cleaning Devices (Non-Halogenated Solvent) • Containers For Oils/Wax/Grease • Cooling Water Towers, Spray Ponds and Canals • Covered Conveyors/Drop Points • Diesel, Gasoline, Fuel Oil, Kerosene, Lube Oil, Waste

Appendix U-1
List of Unregulated Emission Units and/or Activities

EU ID No.	EU Description	Activities/Equipment
039 Contd.	Sugar Cane Processing Facility	and Used Oil Storage Tanks (Non-Nsps) • Electric Ovens For Drying • Emergency Generators • Gear Boxes, Reducers Vents • Ground Water Remediation Stripping Tower • Handling Of Raw Sugar • Industrial Waste Water Tanks (Non-Mact) • Molasses Storage Tanks • Mud Ponds • Oil/Water Seperator/Skimmer Equipment • Painting Operations • Portable Diesel Air Compressors • Portable Electric Generators • Portable Welders • Pressurized Lpg Tanks • Process Water Filtration Intake Screens • Process Wide Flanges and Valves • Pump Operations • Scrubber Water Ponds and Troughs • Stationary Internal Combustion Engines (General) • Vacuum Cleaning Systems • Vehicle Generated Dust • Vents From Hydraulic/Lube Oil Reservoirs • Woodworking and Metal Working Operations • Centrifugals With Mixers • Crystallizers/Receivers • Evaporator Cleaning Operations • Evaporators (W/ Non-Condensable Gas Vent) • Juice Heaters • Mud Filter Condensers Vacuum Pumps • Non-Nsps Process Tanks (Batch, Clarified Juice, Coagulant Mix, Flash, Liming, Mingler, Mixer, Mud Mixing, Pan Feed, Magma, Mud Waste, Muriatic, Sugar Receiver, and Syrup Storage) • Isopropyl alcohol stored in drums • Isopropyl alcohol usage in vacuum pans • Rotary Vacuum Filters • Vacuum Pans with NCG vents, Condensers, And Pumps • Lime Storage Silo and Distribution Systems • Lime Silo Baghouse (5% Opacity) • Diesel Engines for Operation of IWW Pumps • Phosphoric Acid Storage and Distribution Systems • Sodium Hydroxide Storage and Distribution Systems • Mill Crown Wheel Removal Operations • Verical Molasses Crystalice • Cane Mills • Cush-cush Screens/Conveyors and DSM Screens • Hydrochloric Acid Tanks

Appendix U-1
List of Unregulated Emission Units and/or Activities

EU ID No.	EU Description	Activities/Equipment
039 Contd.		• Mill Turbines with Vents • Carbon Slurry Tank • Condensate Tank
040	Sugar Mill Fuel Farm	• Diesel & Gasoline Pumps And Loading Arms • Ground Water Remediation Stripping Tower • Oil/Water Separator/Skimmer Equipment
041	Sugar Mill Potable Water System	• Hydrogen Sulfide Degasifiers • Process Water Discharge Canal • Sulfuric Acid Storage and Distribution System
042	Sugar Mill Sewer Plant	• Sewage Treatment Plant
043	Sugar Refinery	• Bagging Machines • Bulk Curing, Wet Sugar, and Portable Sugar Overflow Bins • Centrifugals • Desweeteners • Evaporators With Condensers • Large And Small Heaters • Primary And Secondary Filters • Refined Sugar Handling, Storage Silo, and Sugar/Syrup Mixer • Rotex Screens • Silo Scale • Sugar Refinery Process Tanks Including: Blackwater, Clarifier, Liquor, Melted Sugar Storage, Melter, Mixer, Reactor, Scums, Secondary Treatment, Sweetwater, and Syrup Storage Tanks and Phosphoric Acid Storage and Distribution System • Vacuum Pans With Condenser and Non-Condensable Gas Vent. • Isopropyl alcohol usage in vacuum pans • Isopropyl alcohol stored in drums
004, 005	Cogeneration Facility	• Boiler Drum Blowdown Tank • Cooling Tower • Diesel Fire Pump Diesel Engine and Diesel Fuel Storage Tank • Hydrogen Sulfide Degasifier • No. 2 Distillate Fuel Oil Storage Tank • Oil Water Separators • Package Sewage Treatment Plant (Non-MACT) • Waste Water Neutralization Tank • Cold Cleaning Devices (parts washers) • Sulfuric Acid Storage and Distribution Systems
045	Sugar Trans-Shipment Facility	• Containers for Oil/Grease/Ink • Diesel Fire Pump Engine • Diesel Fuel Storage Tank • Vehicle Generated Dust

Deleted: ¶
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Table 1-1, Summary of Air Pollutant Standards and Terms

Okeelanta Corporation
Sugarcane Processing, Refining, & Power Generation Facilities

Permit No.: 0990005-012-AV
Facility ID No.: 0990005

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.
Note: The "Equivalent Emissions" listed are for informational purposes only.

				Allowable Emissions			Equivalent Emissions*			
EU ID No.	Pollutant Name	Fuel(s)	Hours/Yr.	Standard(s)	Lbs./hr.	TPY	Lbs./hours	TPY	Regulatory Citation(s)	See Permit Conditions
014	VE[(1)]	FO	8,760	<Twenty (20) % Opacity	-				AC50-191876	A.5
	PM	FO	8,760	0.03 lbs./mmBtu	6.1	26.718	6.1	26.718	AC50-191876	A.5
	PM10	FO	8,760	0.03 lbs./mmBtu	6.1	26.718	6.1	26.718	AC50-191876	A.5
	VOC	FO	8,760	0.03 lbs./mmBtu	6.1	26.718	6.1	26.718	AC50-191876	A.5
	NOx	FO	8,760		22.2	97.236	22.2	97.236	AC50-191876	A.5
	NOx 24-hour block	FO	8,760	0.20 lbs./mmBtu	-	-	-	-		A.5
	NOx 30-day rolling	FO	8,760	0.12 lbs./mmBtu	-	-	-	-		A.5
	NOx 30-day rolling	FO	8,760	0.20 lbs./mmBtu	-	-	-	-		A.5
	CO	FO	8,760	0.11 lbs./mmBtu	22.2	97.236	22.2	97.236	AC50-191876	A.5
	SO_2	FO	8,760	0.06 lbs./mmBtu	12.1	52.998	12.1	52.998	AC50-191876	A.5
	Fuel Oil Sulfur	FO	8,760	.5% Sulfur by weight	-	-	-	-	Not Federally Enforceable	A.7
015, 016, & 017	VOC	FO	8,760	TANKS 2.0	-	0.1085	-	-	AC50-265485	B.4
018	VE	N/A	8,760	<five (5) % Opacity[(4)]	-				0990005-001-AC	C.5
	PM	N/A	8,760	-	-	0.105	0.024	0.105	0990005-001-AC	C.6
019	VE	N/A	8,760	<five (5) % Opacity[(4)]	-				0990005-001-AC	C.5
	PM	N/A	8,760	-	-	6.009	1.372	6.009	0990005-001-AC	C.6
020	VE	N/A	8,760	<five (5) % Opacity[(4)]	-				0990005-001-AC	C.5
	PM	N/A	8,760	-	-	4.115	0.939	4.115	0990005-001-AC	C.6
021	VE	N/A	7,200	<five (5) % Opacity[(4)]	-				0990005-002-AC	D.8
	PM	N/A	7,200	-	-	6.179	1.716	6.179	0990005-002-AC	D.9
	PM10	N/A	7,200	-	-	2.48	0.688	2.48	0990005-002-AC	D.9

Table 1-1, Summary of Air Pollutant Standards and Terms

Okeelanta Corporation
Sugarcane Processing, Refining, & Power Generation Facilities

Permit No.: 0990005-012-AV
Facility ID No.: 0990005

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.
Note: The "Equivalent Emissions" listed are for informational purposes only.

				Allowable Emissions			Equivalent Emissions*			
EU ID No.	Pollutant Name	Fuel(s)	Hours/Yr.	Standard(s)	Lbs./hr.	TPY	Lbs./hours	TPY	Regulatory Citation(s)	See Permit Conditions
022	VE	N/A	7,200	<five (5) % Opacity[4]	-				0990005-002-AC	D.8
	PM	N/A	7,200	-	-	1.748	0.4856	1.748	0990005-002-AC	D.9
	PM10	N/A	7,200	-	-	0.69	0.1917	0.69	0990005-002-AC	D.9
023	VE	N/A	7,200	<five (5) % Opacity[4]	-				0990005-002-AC	D.8
	PM	N/A	7,200	-	-	17.130	4.758	17.130	0990005-002-AC	D.9
	PM10	N/A	7,200	-	-	9.480	2.633	9.480	0990005-002-AC	D.9
024	VE	N/A	7,200	<five (5) % Opacity[4]	-				0990005-002-AC	D.8
	PM	N/A	7,200	-	-	17.130	4.758	17.130	0990005-002-AC	D.9
	PM10	N/A	7,200	-	-	9.480	2.633	9.480	0990005-002-AC	D.9
025	VE	N/A	7,200	<five (5) % Opacity[4]	-				0990005-002-AC	D.8
	PM	N/A	7,200	-	-	6.910	1.920	6.910	0990005-002-AC	D.9
	PM10	N/A	7,200	-	-	0.280	0.078	0.280	0990005-002-AC	D.9
026	VE	N/A	8,760	<five (5) % Opacity[4]	-				0990005-001-AC	C.5
	PM	N/A	8,760	-	-	0.375	0.0856	0.375	0990005-001-AC	C.6
027	VE	N/A	8,760	<five (5) % Opacity[4]	-				0990005-001-AC	C.5
	PM	N/A	8,760	-	-	0.375	0.0856	0.375	0990005-001-AC	C.6
028	VE	N/A	8,760	<five (5) % Opacity[4]	-				0990005-001-AC	C.5
	PM	N/A	8,760	-	-	0.375	0.0856	0.375	0990005-001-AC	C.6
033	VOC	FO	8,760	TANKS 2.0	-	0.1085	-	-	AC50-265485	B.4
034	VE	N/A	8,760	<five (5) % Opacity[4]	-				0990005-002-AC	D.8
	PM	N/A	8,760	-	-	2.86	0.653	2.86	0990005-002-AC	D.9
	PM10	N/A	8,760	-	-	1.35	0.308	1.35	0990005-002-AC	D.9
035	VE	N/A	8,760	<five (5) % Opacity[4]	-				0990005-002-AC	D.8

Table 1-1, Summary of Air Pollutant Standards and Terms

Okeelanta Corporation
Sugarcane Processing, Refining, & Power Generation Facilities

Permit No.: 0990005-012-AV
Facility ID No.: 0990005

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.
Note: The "Equivalent Emissions" listed are for informational purposes only.

				Allowable Emissions			Equivalent Emissions*			
EU ID No.	Pollutant Name	Fuel(s)	Hours/Yr.	Standard(s)	Lbs./hr.	TPY	Lbs./hours	TPY	Regulatory Citation(s)	See Permit Conditions
	PM	N/A	8,760	-	-	1.22	0.278	1.22	0990005-002-AC	D.9
	PM10	N/A	8,760	-	-	058	0.132	0.58	0990005-002-AC	D.9
048	VE	N/A	8,760	<Twenty(20) % Opacity[(4)]	-				0990005-010-AC	G.9
	PM/PM10	N/A	8,760	-	-	0.23	0.278	1.22	0990005-010-AC	G.7
	VOC					3.9			0990005-010-AC	G.6

New Hope Power Partnership
Sugarcane Processing, Refining, & Power Generation Facilities

Permit No.: 0990005-012-AV
Facility ID No.: 0990332

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.
Note: The "Equivalent Emissions" listed are for informational purposes only.

				Allowable Emissions			Equivalent Emissions*			
EU ID No.	Pollutant Name	Fuel(s)	Hours/Yr.	Standard(s)	Lbs./hr.	TPY	Lbs./hours	TPY	Regulatory Citation(s)	See Permit Conditions
001, 002, & 003	Stack Opacity 6-minute block COMS avg.	FO	8,760	<Twenty (20) % Opacity, except for one 6-minute block per hour that is < 27% opacity	-	-	-	-	0990332-014-AC / PSD-FI-196M	F.17
	PM/PM10 3-run test avg.	FO	8,760	0.03 lbs./mmBtu	21.5		21.5		0990332-014-AC / PSD-FI-196M	F.17
	VOC 3-run test avg.	FO	8,760	0.06 lbs./mmBtu	42.9		42.9		0990332-014-AC / PSD-FI-196M	F.17
	NOx 30-day rolling CEMS avg.	FO	8,760	0.15 lbs./mmBtu	107.3		107.3		0990332-014-AC / PSD-FI-196M	F.17
	SO_2				143.0		143.0		0990332-014-AC / PSD-FI-196M	F.17
	SO_2 24-hour rolling CEMS avg.	FO	8,760	0.20 lbs./mmBtu	-	-			0990332-014-AC / PSD-FI-196M	F.17
	SO_2 30-day rolling CEMS	FO	8,760	0.10 lbs./mmBtu	-	-			0990332-014-AC / PSD-FI-196M	F.17

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.
Note: The "Equivalent Emissions" listed are for informational purposes only.

				Allowable Emissions			Equivalent Emissions*			
EU ID No.	Pollutant Name	Fuel(s)	Hours/Yr.	Standard(s)	Lbs./hr.	TPY	Lbs./hours	TPY	Regulatory Citation(s)	See Permit Conditions
	avg.									
	SO_2 12-month rolling CEMS avg.	FO	8,760	0.06 lbs./mmBtu	-	-			0990332-014-AC / PSD-Fl-196M	F.17
	CO	FO	8,760		357.5				0990332-014-AC / PSD-Fl-196M	F.17
	CO 30-day rolling CEMS avg.	FO	8,760	0.50 lbs./mmBtu					0990332-014-AC / PSD-Fl-196M	F.17
	CO 12-month rolling CEMS avg.	FO		0.35 lbs./mmBtu					0990332-014-AC / PSD-Fl-196M	F.17
	Pb 3-run test avg.	FO	8,760	$1.5X10^{-4}$ lbs./mmBtu	N/A				0990332-014-AC / PSD-Fl-196M	F.17
	Hg 3-run test avg.	FO	8,760	$5.4X10^{-6}$ lbs./mmBtu	N/A				0990332-014-AC / PSD-Fl-196M	F.17
	Fl	FO	8,760	$1.9X10^{-4}$ lbs./mmBtu					0990332-014-AC / PSD-Fl-196M	F.17
004	VE	N/A	8,760	<five (5) % Opacity[4]	-				AC50-219413	E.4
	PM	N/A	8,760	0.01 gr/acf [5]	-	-	0.857	-	AC50-219413	E.5

Notes:

(1) Except that 40% opacity is allowed for two minutes in any hour.
(2) Federally enforceable limit.
(3) Permittee's RACT Analysis and requested limits, not yet federally enforceable.
(4) VE of 5% opacity in-lieu of annual stack testing.
(5) PM emission limitation applies to the baghouses.
(6) Except that 27% opacity is allowed for 6 minutes in any hour.
(7) Total from both boilers not to exceed 172.5 tons per year.
(8) Total from both boilers not to exceed 1,154.3 tons per year.
(9) Total from both boilers not to exceed 862.5 tons per year.
(10) Total from both boilers not to exceed 2,012.5 tons per year.
(11) Total from both boilers not to exceed 345.0 tons per year.
(12) Total from both boilers not to exceed 0.454 tons per year.
(13) Total from both boilers not to exceed 0.030 tons per year.
(14) Total from both boilers not to exceed 0.0052 tons per year.
(15) Total from both boilers not to exceed 21.2 tons per year.
(16) Total from both boilers not to exceed 34.6 tons per year.

BG - Bagasse
WW - Wood Waste
FO - Fuel Oil
BC - Bituminous Coal
CF - Carbonaceous Fuels

Table 2-1, Summary of Compliance Requirements

Okeelanta Corporation
Sugarcane Processing, Refining & Power Generation Facilities

Permit No.: 0990005-012-AV
Facility Id No.: 0990005

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.
Notes: * the frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

Emissions Unit ID No.	Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date*	Minimum Compliance Test Duration	CMS**	See Permit Conditions
014	VE	FO	Method 9	Annually(1)		60 Minutes	X	A.9 & A.16
	NOx	FO	Method 7E	Annually(1)		Three Runs	X	A.9 & A.16
	CO	FO	Method 10	Annually(1)		Three Runs		A.9
	Fuel Oil Sulfur	FO	Recordkeeping	Daily	-	-		A.13
	Steam Production	FO	Recordkeeping	CMS	-	-	X	A.14
	Maximum Heat Input	FO	Recordkeeping	Daily	-	-		A.14
	Oil Sulfur Content	FO	Recordkeeping	Daily	-	-		A.13
	Hours of Operation	FO	Recordkeeping	Daily	-	-		A.14
015, 016, & 017	Monthly Throughput	-	Recordkeeping	Daily	-	-		B.6
	Volatile organic Liquid Types	-	Recordkeeping	Daily	-	-		B.6
018	VE	-	Method 9	Annually(1) & Daily	-	30 Minutes		C.7, C.9, & C.12
	PM/PM10	-	Methods 1-5	Special Test	-	Three Runs		C.8 & C.10
019	VE	-	Method 9	Annually(1) & Daily	-	30 Minutes		C.7, C.9, & C.12
	PM/PM10	-	Methods 1-5	Special Test	-	Three Runs		C.8 & C.10
	Sugar Packaged (tons)	-	Recordkeeping	-	Daily	-		C.11
	Packaging Lines Operated	-	Recordkeeping	-	Daily	-		C.11
	Hours of Operation	-	Recordkeeping	-	Daily	-		C.11

Table 2-1, Summary of Compliance Requirements

Okeelanta Corporation
Sugarcane Processing, Refining & Power Generation Facilities

Permit No.: 0990005-012-AV
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Notes: * the frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

Emissions Unit ID No.	Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date*	Minimum Compliance Test Duration	CMS**	See Permit Conditions
020	VE	-	Method 9	Annually(1) & Daily	-	30 Minutes		C.7, C.9, & C.12
	PM/PM10	-	Methods 1-5	Special Test	-	Three Runs		C.8 & C.10
	Sugar Packaged (tons)	-	Recordkeeping	-	Daily	-		C.11
021	VE	-	Method 9	Annually(1) & Daily	-	30 Minutes		D.10 & D.12
	PM	-	Methods 1-5	Special Test	-	Three Runs		D.11
	PM10	-	Methods 201 & 201A	Special Test	-	Three Runs		D.11
	Sugar Processed (tons)	-	Recordkeeping	-	Daily	-		D.14
	Hours of Operation	-	Recordkeeping	-	Daily	-		D.14
022	VE	-	Method 9	Annually(1) & Daily	-	30 Minutes		D.10 & D.12
	PM	-	Methods 1-5	Special Test	-	Three Runs		D.11
	PM10	-	Methods 201 & 201A	Special Test	-	Three Runs		D.11
	Sugar Processed (tons)	-	Recordkeeping	-	Daily	-		D.14
	Hours of Operation	-	Recordkeeping	-	Daily	-		D.14
023 & 024	VE	-	Method 9	Annually(1) & Daily	-	30 Minutes		D.10 & D.12
	PM	-	Methods 1-5	Special Test	-	Three Runs		D.11
	PM10	-	Methods 201 & 201A	Special Test	-	Three Runs		D.11
	Sugar Processed (tons)	-	Recordkeeping	-	Daily	-		D.14
	Hours of Operation	-	Recordkeeping	-	Daily	-		D.14

Table 2-1, Summary of Compliance Requirements

Okeelanta Corporation
Sugarcane Processing, Refining & Power Generation Facilities

Permit No.: 0990005-012-AV
Facility Id No.: 0990005

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Notes: * the frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

Emissions Unit ID No.	Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date*	Minimum Compliance Test Duration	CMS**	See Permit Conditions
025	VE	-	Method 9	Annually(1) & Daily	-	30 Minutes		D.10 & D.12
	PM	-	Methods 1-5	Special Test	-	Three Runs		D.11
	PM10	-	Methods 201 & 201A	Special Test	-	Three Runs		D.11
	Sugar Dried (tons)	-	Recordkeeping	-	Daily	-		D.14
	Hours of Operation	-	Recordkeeping	-	Daily	-		D.14
026, 027, & 028	VE	-	Method 9	Annually(1) & Daily	-	30 Minutes		C.7, C.9 & C.12
	PM	-	Methods 1-5	Special Test	-	Three Runs		C.8 & C.10
	PM10	-	Methods 201 & 201A	Special Test	-	Three Runs		C.8 & C.10
	Silo Loaded	-	Recordkeeping	-	Daily	-		C.11
	Sugar Transferred (Tons)	-	Recordkeeping	-	Daily	-		C.11
033	Monthly Throughput	-	Recordkeeping	Daily	-	-		B.6
034	VE	-	Method 9	Annually(1) & Daily	-	30 Minutes		D.10 & D.12
	PM	-	Methods 1-5	Special Test	-	Three Runs		D.11
	PM10	-	Methods 201 & 201A	Special Test	-	Three Runs		D.11
	Sugar Transferred (Tons)	-	Recordkeeping	-	Daily	-		D.14
035	VE	-	Method 9	Annually(1) & Daily	-	30 Minutes		D.10 & D.12
	PM	-	Methods 1-5	Special Test	-	Three Runs		D.11
	PM10	-	Methods 201 & 201A	Special Test	-	Three Runs		D.11
	Sugar Transferred (Tons)	-	Recordkeeping	-	Daily	-		D.14

Table 2-1, Summary of Compliance Requirements

Okeelanta Corporation
Sugarcane Processing, Refining & Power Generation Facilities

Permit No.: 0990005-012-AV
Facility Id No.: 0990005

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.
Notes: * the frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

Emissions Unit ID No.	Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date*	Minimum Compliance Test Duration	CMS**	See Permit Conditions
048	Volatile organic Liquid Types	-	Recordkeeping	Daily	-	-		G.13
	Hours of Operation	-	Recordkeeping	Daily	-	-		G.13
	Amounts and types of coating used	-	Recordkeeping	Daily	-	-		G.13
	Inventory of VOCs and Solvents used	-	Recordkeeping	Daily	-	-		G.13

New Hope Corporation
Sugarcane Processing, Refining & Power Generation Facilities

Permit No.: 0990005-012-AV
Facility Id No.: 0990332

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**CMS [=] continuous monitoring system

Emissions Unit ID No.	Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date*	Minimum Compliance Test Duration	CMS**	See Permit Conditions
001, 002, & 003	Sample & Velocity Traverses	BG/WW/FO/BC	Method 1	Annually	-	Three Runs		F.20
	Stack Gas Velocity & Volumetric Flow Rate	BG/WW/FO/BC	Method 2	Annually	-	Three Runs		F.20
	CO_2, O_2, Excess Air, and Dry Molecular Weight	BG/WW/FO/BC	Method 3A	Annually	-	Three Runs	O_2	F.20
	Moisture Content	BG/WW/FO/BC	Method 4	Annually	-	Three Runs		F.20
	PM (TSP)	BG/WW/FO/BC	Method 5	Annually	-	Three Runs		F.20
	SO_2	BG/WW/FO/BC	Method 6 or 6C	Annually	-	Three Runs	X	F.20

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**CMS [=] continuous monitoring system

Emissions Unit ID No.	Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date*	Minimum Compliance Test Duration	CMS**	See Permit Conditions
	NOx	BG/WW/FO/BC	Method 7 or 7E	Annually	-	Three Runs	X	F.20
	VE	BG/WW/FO/BC	Method 9	Annually	-	Three Runs	X	F.20
	CO	BG/WW/FO/BC	Method 10	Annually	-	Three Runs	X	F.20
	Pb	BG/WW/FO/BC	Method 12	Annually	-	Three Runs		F.20
	SO_2 & NOx emission rates	BG/WW/FO/BC	Method 19	Annually	-	Three Runs		F.20
	VOC	BG/WW/FO/BC	Method 25 or 25 & 18 concurrently	Annually	-	Three Runs		F.20
	Multiple Metals Emissions	BG/WW/FO/BC	Method 29	Annually	-	Three Runs		F.20
	Hg	BG/WW/FO/BC	Method 101A	Annually	-	Three Runs		F.20
	Steam Production	BG/WW/FO/BC	Recordkeeping	CMS	-		X	F.20
	Maximum Heat Input	BG/WW/FO/BC	Recordkeeping	Daily	-			F.20
	Fuel Types	BG/WW/FO/BC	Recordkeeping	Daily	-			F.14
	Hours of Operation	BG/WW/FO/BC	Recordkeeping	Daily	-			F.20
	Combustion Control Performance	BG/WW/FO/BC	Recordkeeping	Daily	-			F.7
	AQCSs	BG/WW/FO/BC	Recordkeeping	Daily	-			F.20
	Fuels & Ash	BG/WW/FO/BC	Recordkeeping	Daily	-			F.11
	O/M Plan		Recordkeeping	As required	-	-		F.19
004	Fuel Management Plan	-	Recordkeeping	as required	-	-		E.7
	Ash Management Plan	-	Recordkeeping	as required	-	-		E.8
	O/M Plans	-	Recordkeeping	as required	-	-		E.9
	VE	-	Method 9	Annually(2)		30 Minutes		E.10 &E.12
	PM	-	Methods 1-5	Annually(2)		Three Runs		E.11

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Notes: * the frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

Emissions Unit ID No.	Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date*	Minimum Compliance Test Duration	CMS**	See Permit Conditions
	PM10	-	Methods 201 & 201A	Special Test	-	Three Runs		E.11
	Coal Handling	-	Recordkeeping	per shipment	-	-		E.13
	Biomass Handling	-	Recordkeeping	per shipment	-	-		E.13
	Fly Ash Handling	-	Recordkeeping	per shipment	-	-		E.13

Notes:
(1). A compliance test to be conducted during each federal fiscal year.

BG - Bagasse
WW - Wood Waste
FO - Fuel Oil
BC - Bituminous Coal