ATTACHMENT A: Boundaries of the Certified Site
ATTACHMENT B: Boundaries of the Certified Area
ATTACHMENT C: Wetland Mitigation Plan (if any)
APPENDIX I. Air Construction Permits
In the matter of an Application for Permit by:

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

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

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.

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

Permission Number: AC50-219413
Expiry 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 DeNOx (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:
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
PERMITTEE: Okeelanta Power Limited Partnership

Permit Number: AC50-219413
PSD-FL-196
Expiration Date: July 1, 1996

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.
PERMITTEE: Okeelanta Power Limited Partnership

Permit Number: AC50-219413
PSD-PL-196
Expiration Date: July 1, 1996

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 NOx; 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 (NOₓ), sulfur dioxide (SO₂), oxygen (O₂), 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, NOₓ, 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 SO₂/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 SO₂ 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 SO₂ 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. AG50-169210, 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. Sed, 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:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Limit (per boiler)</th>
<th>Total All Three Boilers</th>
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<tbody>
<tr>
<td></td>
<td>Biomass</td>
<td>No. 2 Oil</td>
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<tr>
<td>Particulate (TSP)</td>
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<td>Particulate (PM&lt;sub&gt;10&lt;/sub&gt;)</td>
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<td>21.5</td>
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<tr>
<td>Sulfur Dioxide</td>
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<td>3-hour average</td>
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<td>24-hour average</td>
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<tr>
<td>Annual average</td>
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<tr>
<td>Nitrogen Oxides</td>
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<tr>
<td>Annual average</td>
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<td>107.3&lt;sup&gt;b&lt;/sup&gt;</td>
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<td>Carbon Monoxide</td>
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<td>8-hour average</td>
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<td>Volatile Organic Compounds</td>
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<td>Lead</td>
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<td>Mercury</td>
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Page 10 of 14
PERMITTEE: Okeelanta Power Limited Partnership
Permit Number: AC50-219413
Expiration Date: July 1, 1996

SPECIFIC CONDITIONS:

<table>
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<tr>
<th></th>
<th>3.5 x 10^{-7}</th>
<th>0.00017</th>
<th>5.9 x 10^{-6}</th>
<th>0.0029</th>
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<td>2.15</td>
<td>0.0015</td>
<td>0.74</td>
<td>0.036</td>
</tr>
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</table>

^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 P.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.

<table>
<thead>
<tr>
<th>EPA Method*</th>
<th>For Determination of</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Selection of sample site and velocity traverses.</td>
</tr>
<tr>
<td>2</td>
<td>Stack gas flow rate when converting concentrations to or from mass emission limits.</td>
</tr>
<tr>
<td>3 or 3A</td>
<td>Gas analysis when needed for calculation of molecular weight or percent O₂.</td>
</tr>
<tr>
<td>4</td>
<td>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.</td>
</tr>
<tr>
<td>5</td>
<td>Particulate matter concentration and mass emissions.</td>
</tr>
<tr>
<td>201 or 201A</td>
<td>PM₁₀ emissions.</td>
</tr>
<tr>
<td>6, 6C, or 19</td>
<td>Sulfur dioxide emissions from stationary sources.</td>
</tr>
<tr>
<td>7 or 7E</td>
<td>Nitrogen oxide emissions from stationary sources.</td>
</tr>
<tr>
<td>8</td>
<td>Sulfuric acid mist.</td>
</tr>
<tr>
<td>9</td>
<td>Visible emission determination of opacity.</td>
</tr>
<tr>
<td></td>
<td>- At least three one hour runs to be conducted simultaneously with particulate testing.</td>
</tr>
<tr>
<td></td>
<td>- At least one truck unloading into the mercury reactant storage silo (from start to finish).</td>
</tr>
<tr>
<td>10</td>
<td>Carbon monoxide emissions from stationary sources.</td>
</tr>
<tr>
<td>12</td>
<td>Determination of inorganic lead emissions from stationary sources.</td>
</tr>
<tr>
<td>13A or 13B</td>
<td>Fluoride emissions from stationary sources.</td>
</tr>
<tr>
<td>18 or 25</td>
<td>Volatile organic compounds concentration.</td>
</tr>
<tr>
<td>101A</td>
<td>Determination of particulate and gaseous mercury emissions.</td>
</tr>
<tr>
<td>104</td>
<td>Determination of beryllium emissions from stationary sources.</td>
</tr>
<tr>
<td>108</td>
<td>Determination of particulate and gaseous arsenic emissions.</td>
</tr>
</tbody>
</table>
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, 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**

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Biomass</th>
<th>No. 2 fuel oil</th>
<th>Coal</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO₂</td>
<td>0.10/71.5</td>
<td>0.05/24.5</td>
<td>1.2/588</td>
</tr>
<tr>
<td>Beryllium</td>
<td>--</td>
<td>3.5E-7/1.7E-4</td>
<td>5.9E-6/2.9E-3</td>
</tr>
<tr>
<td>Fluorides</td>
<td>--</td>
<td>6.3E-6/3.0E-3</td>
<td>2.4E-2/11.8</td>
</tr>
</tbody>
</table>

* 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**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Limit (lbs/MMBtu)</th>
<th>Control Technology</th>
<th>EPA Test Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sulfur Dioxide</td>
<td>0.10 (biomass)</td>
<td>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</td>
<td>6, 6C, or 19 and continuous emissions monitoring.</td>
</tr>
<tr>
<td></td>
<td>0.02 (30-day rolling avg. on biomass)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>0.05 (No. 2 fuel oil)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1.2 (coal) (30-day rolling average)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beryllium</td>
<td>3.5E-7 (No. 2 fuel oil)</td>
<td>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</td>
<td>104</td>
</tr>
<tr>
<td></td>
<td>5.9E-6 (coal)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Fluorides

<table>
<thead>
<tr>
<th>Fuel Source</th>
<th>Max. Heat Input of Less Than 25 Percent on a Calendar Quarter Basis</th>
<th>13A or 13B</th>
</tr>
</thead>
<tbody>
<tr>
<td>6.3E-6 (No. 2 fuel oil)</td>
<td>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</td>
<td>13A or 13B</td>
</tr>
<tr>
<td>2.4E-2 (coal)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ at the proposed emission rate has been calculated to be 0.8, 74, and 164 ug/m³ 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/m³ 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/m³. 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  

Date:  
September 17  1993

Approved by:  

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

Date:  
September 27  1993
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 NOx, 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 NOx - 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 NOx air pollution control is use of a selective non-catalytic reduction system designed to achieve at least 40 percent NOx reduction efficiency. The estimated NOx 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 NOx - Emitting Facilities, this RACT determination is based on the applicant’s proposal, published documents, and technological feasibility.
RACT Determined by DEP

<table>
<thead>
<tr>
<th>Fuel</th>
<th>VOC lbs/MMBtu</th>
<th>Control</th>
<th>NOx lbs/MMBtu</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass</td>
<td>0.06</td>
<td>Boiler Design, Good operation practice using the oxygen meter</td>
<td>0.15</td>
<td>Non-Catalytic reduction system</td>
</tr>
<tr>
<td>No. 2 Fuel Oil</td>
<td>0.03</td>
<td></td>
<td>0.15</td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>0.03</td>
<td></td>
<td>0.17</td>
<td></td>
</tr>
</tbody>
</table>

**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.

**NOx:** The applicant will use a selective non-catalytic reduction system to lower NOx emissions. The proposed NOx 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 NOx 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 NOx 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
In the Matter of an  
Application for Permit Amendment

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.

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.

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

“Protect, Conserve and Manage Florida’s Environment and Natural Resources”

Printed on recycled paper.
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
Mr. Dennis V. Space  
Page Two  
June 12, 1996  

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
Mr. Dennis V. Space
Page Four
June 12, 1996

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.

[Signature] 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:

Manufacturers: 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 PM10 (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
NOTICE OF PERMIT AMENDMENT

In the matter of an
Application for Permit Amendment by:

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

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

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.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
904-488-1244

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 August 20, 1998, 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
Date

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

"Protect, Conserve and Manage Florida's Environment for Our Future."

Printed on recycled paper.
CERTIFIED MAIL RETURN - RECEIPT REQUESTED

February 19, 1996

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 AC50-215413 and PSD-FL-196.

Sincerely,

Howard L. Rhodes, Director
Division of Air Resources Management

Enclosures

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

"Protect, Conserve and Manage Florida's Environment and Natural Resources"
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,

[Signature]

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.

(Clerk)  
5-5-97  
(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 33476

DEP File No. 6990332-004-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.

[Signature]

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, PBCFHU

Brian Beals, EPA
John Bunyak, NPS
David Buff, Golder Associates
David Dec, 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.

[Signature] 4/18/97
(Clerk)  (Date)
CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Dennis V. Space, General Manager
Orlando 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 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,

[Signature]

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/wh/t
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

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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 (SO₂). 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 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 SO₂ 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 SO₂, 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:

"Protect, Conserve and Manage Florida's Environment and Natural Resources"

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<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Biomass (lb/MMBtu)</th>
<th>No. 2 Oil (lb/MMBtu)</th>
<th>Bit. Coal (lb/MMBtu)</th>
<th>Total Three Boilers (TPY)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate (TSP)</td>
<td>0.03</td>
<td>21.5</td>
<td>0.03</td>
<td>14.7</td>
</tr>
<tr>
<td>Particulate (PM₁₀)</td>
<td>0.03</td>
<td>21.5</td>
<td>0.03</td>
<td>14.7</td>
</tr>
<tr>
<td>Sulfur Dioxide</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3-hour average</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>24-hour average</td>
<td>0.10</td>
<td>71.5</td>
<td>0.05</td>
<td>24.5</td>
</tr>
<tr>
<td>Annual Average</td>
<td>0.02-a</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bagasse</td>
<td>0.02 a</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wood Waste</td>
<td>0.05a c</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nitrogen Oxides</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual average</td>
<td>0.15 a</td>
<td>107.3 a</td>
<td>0.15 a</td>
<td>73.5 a</td>
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<tr>
<td>Carbon Monoxide</td>
<td>0.35</td>
<td>250.3</td>
<td>0.2 0.35</td>
<td>98.0 171.5</td>
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<tr>
<td>Volatile Organic</td>
<td>0.06</td>
<td>42.9</td>
<td>0.03</td>
<td>14.7</td>
</tr>
<tr>
<td>Compounds</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lead</td>
<td>2.5 x 10^-5</td>
<td>0.018</td>
<td>3.9 x 10^-7</td>
<td>0.0004</td>
</tr>
<tr>
<td>Bagasse</td>
<td>2.5 x 10^-5</td>
<td>0.018</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wood Waste</td>
<td>1.6 x 10^-4c</td>
<td>0.114c</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mercury</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bagasse</td>
<td>6.3 x 10^-6</td>
<td>0.0045b</td>
<td>8.4 x 10^-6</td>
<td>0.0041</td>
</tr>
<tr>
<td>Wood Waste</td>
<td>3.43 x 10^-6b</td>
<td>0.0039b</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beryllium</td>
<td>0.29 x 10^-6-e</td>
<td>0.00024</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>4.0 x 10^-6 c</td>
<td>0.0029</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fluorides</td>
<td>3.5 x 10^-7</td>
<td>0.00017</td>
<td>5.9 x 10^-6</td>
<td>0.0029</td>
</tr>
<tr>
<td>Sulfuric Acid Mist</td>
<td>6.3 x 10^-6</td>
<td>0.0003</td>
<td>0.024</td>
<td>11.8</td>
</tr>
</tbody>
</table>

- **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.

<table>
<thead>
<tr>
<th>EPA Method*</th>
<th>For Determination of</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Selection of sample site and velocity traverses.</td>
</tr>
<tr>
<td>2</td>
<td>Stack gas flow rate when converting concentrations to or from mass emission limits.</td>
</tr>
<tr>
<td>3 or 3A</td>
<td>Gas analysis when needed for calculation of molecular weight or percent O2.</td>
</tr>
<tr>
<td>4</td>
<td>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.</td>
</tr>
<tr>
<td>5</td>
<td>Particulate matter concentration and mass emissions.</td>
</tr>
<tr>
<td>201 or 201A</td>
<td>PM10 emissions.</td>
</tr>
<tr>
<td>6, 6C, or 19</td>
<td>Sulfur dioxide emissions from stationary sources.</td>
</tr>
<tr>
<td>7, or 7E</td>
<td>Nitrogen oxide emissions from stationary sources.</td>
</tr>
<tr>
<td>8 (modified)</td>
<td>Sulfuric acid mist.**</td>
</tr>
<tr>
<td>9</td>
<td>Visible emission determination of opacity.</td>
</tr>
<tr>
<td>10</td>
<td>At least three one hour runs to be conducted simultaneously with particulate testing.</td>
</tr>
<tr>
<td>12</td>
<td>At least one truck unloading into the mercury reactant storage silo (from start to finish).</td>
</tr>
<tr>
<td>13A or 13B</td>
<td>Carbon monoxide emissions from stationary sources.</td>
</tr>
<tr>
<td>18 or 25</td>
<td>Determination of inorganic lead emissions from stationary sources.</td>
</tr>
<tr>
<td>101A</td>
<td>Fluoride emissions from stationary sources.</td>
</tr>
<tr>
<td>104</td>
<td>Volatile organic compounds concentration.</td>
</tr>
<tr>
<td>108</td>
<td>Determination of particulate and gaseous mercury emissions.</td>
</tr>
<tr>
<td>EMTIC Test Method</td>
<td>Determination of beryllium emissions from stationary sources.</td>
</tr>
<tr>
<td>CTM-012 WPF</td>
<td>Determination of particulate and gaseous arsenic emissions.</td>
</tr>
<tr>
<td></td>
<td>Chromium and copper emissions.</td>
</tr>
</tbody>
</table>

* 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.

Karin Jellen 10-24-97
(Clerk) (Date)
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 underlined 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:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Biomass (lb/MMBtu)</th>
<th>No. 2 Oil (lb/hr)</th>
<th>Bit. Coal (lb/MMBtu)</th>
<th>Total Three Boilers (TPY)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate (TSP)</td>
<td>0.03</td>
<td>21.5</td>
<td>0.03</td>
<td>14.7</td>
</tr>
<tr>
<td>Particulate (PM10)</td>
<td>0.03</td>
<td>21.5</td>
<td>0.03</td>
<td>14.7</td>
</tr>
<tr>
<td>Sulfur Dioxide</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3-hour average</td>
<td>0.10</td>
<td>71.5</td>
<td>0.05</td>
<td>24.5</td>
</tr>
<tr>
<td>24-hour average</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual Average</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Bagasse)</td>
<td>0.02 a</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Wood Waste)</td>
<td>0.05 a c</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nitrogen Oxides</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual average</td>
<td>0.15 a</td>
<td>107.3 a</td>
<td>0.15 a</td>
<td>73.5 a</td>
</tr>
</tbody>
</table>

"Protect, Conserve and Manage Florida's Environment and Natural Resources"
Carbon Monoxide

<table>
<thead>
<tr>
<th>24-hour 30-day rolling avg.</th>
<th>0.35 a</th>
<th>250.3 a</th>
<th>0.35 a</th>
<th>171.5 a</th>
<th>0.35 a</th>
<th>171.5 a</th>
<th>2,012.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volatile Organic Compounds</td>
<td>0.06</td>
<td>42.9</td>
<td>0.03</td>
<td>14.7</td>
<td>0.03</td>
<td>14.7</td>
<td>345</td>
</tr>
<tr>
<td>Lead (Bagasse)</td>
<td>2.5 x 10^3 b</td>
<td>0.018 b</td>
<td>8.9 x 10^-7</td>
<td>0.0004</td>
<td>6.4 x 10^-7</td>
<td>0.031</td>
<td>0.454 f</td>
</tr>
<tr>
<td>&quot; (Wood Waste)</td>
<td>1.6 x 10^4 c</td>
<td>0.114 c</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mercury (Bagasse)</td>
<td>5.43 x 10^8 b</td>
<td>0.0039 b</td>
<td>2.4 x 10^6</td>
<td>0.00118</td>
<td>8.4 x 10^6</td>
<td>0.0041</td>
<td>0.0300 f</td>
</tr>
<tr>
<td>&quot; (Wood Waste)</td>
<td>4.0 x 10^6 c</td>
<td>0.0029 c</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beryllium</td>
<td>---</td>
<td>---</td>
<td>3.5 x 10^-7</td>
<td>0.00017</td>
<td>5.9 x 10^-6</td>
<td>0.0029</td>
<td>0.0052</td>
</tr>
<tr>
<td>Fluorides</td>
<td>---</td>
<td>---</td>
<td>6.3 x 10^-6</td>
<td>0.0003</td>
<td>0.024</td>
<td>11.8</td>
<td>21.2</td>
</tr>
<tr>
<td>Sulfuric Acid Mist</td>
<td>0.003</td>
<td>2.15</td>
<td>0.0015</td>
<td>0.74</td>
<td>0.036</td>
<td>17.6</td>
<td>34.6</td>
</tr>
</tbody>
</table>

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.*


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.

<table>
<thead>
<tr>
<th>EPA Method*</th>
<th>For Determination of</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Selection of sample site and velocity traverses.</td>
</tr>
<tr>
<td>2</td>
<td>Stack gas flow rate when converting concentrations to or from mass emission limits.</td>
</tr>
<tr>
<td>3 or 3A</td>
<td>Gas analysis when needed for calculation of molecular weight or percent O$_2$.</td>
</tr>
<tr>
<td>4</td>
<td>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.</td>
</tr>
<tr>
<td>5</td>
<td>Particulate matter concentration and mass emissions.</td>
</tr>
<tr>
<td>201 or 201A</td>
<td>PM$_{10}$ emissions.</td>
</tr>
<tr>
<td>6, 6C, or 19</td>
<td>Sulfur dioxide emissions from stationary sources.</td>
</tr>
<tr>
<td>7, or 7E</td>
<td>Nitrogen oxide emissions from stationary sources.</td>
</tr>
<tr>
<td>8 (modified)</td>
<td>Sulfuric acid mist. **</td>
</tr>
</tbody>
</table>
| 9           | Visible emission determination of opacity.
<p>|             | - 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. |</p>
<table>
<thead>
<tr>
<th>EPA Method*</th>
<th>For Determination of</th>
</tr>
</thead>
<tbody>
<tr>
<td>104</td>
<td>Determination of beryllium emissions from stationary sources.</td>
</tr>
<tr>
<td>108</td>
<td>Determination of particulate and gaseous arsenic emissions.</td>
</tr>
<tr>
<td>EMTIC Test Method</td>
<td>Chromium and copper emissions.</td>
</tr>
<tr>
<td>CTM-012.WPF</td>
<td></td>
</tr>
</tbody>
</table>

* 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 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 monitoring 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]
Mr. James Meriwether  
June 22, 1999  
Page 5

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,

[Signature]

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.

[Signature]  
(Clerk)  6-24-99  
(Date)
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.”

"More Protection, Less Process"
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 Stormer, PBCHD
Mr. James Meriwether, Okeelanta Power L.P.  Mr. Ray Blackburn, SD
Mr. Ricardo Lima, Okeelanta Corporation  Mr. Gregg Worley, EPA
Mr. David Dec, Landers & Parsons  Mr. John Bunyak, NPS
Mr. David Buff, Golder Associates

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 Hayase 11/6/00
(Clerk)  (Date)
CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

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

Okeclanta Power L.P. operates a biomass cogeneration plant located near Highway 27, approximately 6 miles south of South Bay in Palm Beach County, Florida. Okeclanta 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, Okeclanta 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

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Printed on recycled paper.
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 SO2 emissions. It shall also include the average heat inputs from each fuel, the average power generation, and the hours of operation for each day.

c. 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/PM10, SO2, and VOC in accordance with methodology provided in the letter application for this project and generally described as follows. Emissions of CO, NOx, and SO2 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/PM10 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.

<table>
<thead>
<tr>
<th>Operating Hours</th>
<th>Heat Input mmBTU/year</th>
<th>Annual Emissions, Tons Per Year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>CO</td>
</tr>
<tr>
<td>Past Actual Emissions Prior to Project</td>
<td>20,170</td>
<td>10,725,416</td>
</tr>
<tr>
<td>PSD Significant Emission Rates (Table 212.400-2, F.A.C.)</td>
<td>----</td>
<td>----</td>
</tr>
<tr>
<td>Future Actual Emissions, Above Which May Trigger PSD Review</td>
<td>----</td>
<td>----</td>
</tr>
<tr>
<td>Representative Actual Emissions for Calendar Year</td>
<td>----</td>
<td>----</td>
</tr>
<tr>
<td>Do the representative actual annual emissions trigger PSD review?</td>
<td>----</td>
<td>----</td>
</tr>
</tbody>
</table>

* 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, SO₂ 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 SO₂ / mmBTU of heat input”. {Permitting Note: The SO₂ 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.

[Signature]
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 Banyak, 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 1/24/01
(Clerk) (Date)
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 E. 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.

In the matter of an
Application for Permit by:

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

DER File No. AC50-219413
PSP-PL-196
Palm Beach County

Enclosed is construction Permit Number AC50-219413 (PSP-PL-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

[Signature]
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 April 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) (Date)

Clerk Stamp

Copies furnished to:
David Knowles, SD
Israel Goldman, SEB
James Stormer, PBCHD
Jewell Harper, EPA
John Buryak, HPS
David Buff, KBH
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
The Technical Evaluation and Preliminary Determination for a permit to construct (AC 50-218413/PSD-FL-156) a 71.25 megawatt (MW) electric cogeneration facility for Okeelanta Power Limited Partnership, P.O. Box 86, South Bay, Florida 33463, 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 editorial 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, i-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 50-219-13 (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

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 5 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 450 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 DeNOx (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 2240.1 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:


Page 1 of 14
PERMITTEE: Okeelanta Power Limited Partnership

Permit Number: AC50-219413
Expiration Date: July 1, 1996

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 403.856 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 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.

6. 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.
PERMITES:  Permit Number:  AC50-219413
Okeelanta Power Limited  PSD-FL-196
Partnership  Expiration Date:  July 1, 1996

GENERAL CONDITIONS:

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-73C.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 NOx; 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 (NOx), sulfur dioxide (SO2), oxygen (O2), 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, NOx, 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.

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 $11.5 \times 10^{12}$ Btu per year. Steam production of each boiler shall not exceed an average of 455,418 lbs/hr at 1,500 psig, 875°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 251, 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 SO₂/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 SO₂ 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 SO₂ 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. AC50-169210, 190690, 175414, 190693, 175411, 182215, 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 910,636 lb/hr steam is generated in the cogeneration boilers, steam in excess of 910,636 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. Soil, 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 37 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:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Limit (per boiler)</th>
<th>Total: All 3 boilers</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Biomass (lb/MMBtu/hr)</td>
<td>No. 2 Oil (lb/MMBtu/hr)</td>
</tr>
<tr>
<td>Particulate (1SF)</td>
<td>0.03</td>
<td>0.13</td>
</tr>
<tr>
<td>Particulate (PM10)</td>
<td>0.03</td>
<td>0.13</td>
</tr>
<tr>
<td>Sulfur Dioxide</td>
<td>0.70</td>
<td>7.1</td>
</tr>
<tr>
<td>3-hour average</td>
<td></td>
<td></td>
</tr>
<tr>
<td>24-hour average</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual average</td>
<td>0.20</td>
<td></td>
</tr>
<tr>
<td>Nitrogen Oxides</td>
<td>0.10</td>
<td>1.1</td>
</tr>
<tr>
<td>Annual average</td>
<td>0.25</td>
<td></td>
</tr>
<tr>
<td>Carbon Monoxide</td>
<td></td>
<td>1.2</td>
</tr>
<tr>
<td>Annual average</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Volatile Organic Carbon</td>
<td>1.14</td>
<td>11.4</td>
</tr>
<tr>
<td>Aerosol</td>
<td>0.4 \times 10^{-3}</td>
<td>0.4 \times 10^{-3}</td>
</tr>
<tr>
<td>Residual Gas</td>
<td>0.4 \times 10^{-3}</td>
<td></td>
</tr>
</tbody>
</table>
PERMITTEE:  
Okeelanta Power Limited  
Partnership

 Permit Number:  AC50-219413  
PSD-FL-196

Expiration Date:  July 1, 1996

SPECIFIC CONDITIONS:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>g/h</th>
<th>30-day avg.</th>
<th>1-hour avg.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beryllium</td>
<td>3.5 x 10^{-7}</td>
<td>0.00017</td>
<td>5.9 x 10^{-6}</td>
</tr>
<tr>
<td>Fluorides</td>
<td>1.3 x 10^{-6}</td>
<td>0.003</td>
<td>0.024</td>
</tr>
<tr>
<td>Sulfuric Acid Mist</td>
<td>0.003</td>
<td>2.15</td>
<td>0.0015</td>
</tr>
</tbody>
</table>

- Compliance based on 30-day rolling average, per 40 CFR 60, Subpart D.
- Emission limit for bagasse. Subject to revision after testing pursuant to Specific Conditions Nos. 24 and 25.
- Emission limit for wood waste. Subject to revision after testing pursuant to Specific Conditions Nos. 24 and 25.
- The emission limit shall be prorated when more than one type of fuel is burned in a boiler.
- 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.
- 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

2. Stack Testing

- a. Within 50 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 60.44a.

- 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.

<table>
<thead>
<tr>
<th>EPA Method*</th>
<th>For Determination of</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Selection of sample site and velocity traverses.</td>
</tr>
<tr>
<td>2</td>
<td>Stack gas flow rate when converting concentrations to or from mass emission limits.</td>
</tr>
<tr>
<td>3 or 3A</td>
<td>Gas analysis when needed for calculation of molecular weight or percent O₂.</td>
</tr>
<tr>
<td>4</td>
<td>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.</td>
</tr>
<tr>
<td>5</td>
<td>Particulate matter concentration and mass emissions.</td>
</tr>
<tr>
<td>201 or 201A</td>
<td>PM₁₀ emissions.</td>
</tr>
<tr>
<td>6, 6C, or 15</td>
<td>Sulfur dioxide emissions from stationary sources.</td>
</tr>
<tr>
<td>7 or 7C</td>
<td>Nitrogen oxide emissions from stationary sources.</td>
</tr>
<tr>
<td>8</td>
<td>Sulfuric acid mist.</td>
</tr>
<tr>
<td>9</td>
<td>Visible emission determination of opacity.</td>
</tr>
<tr>
<td></td>
<td>- At least three one hour runs to be conducted simultaneously with particulate testing.</td>
</tr>
<tr>
<td></td>
<td>- At least one truck unloading into the mercury reactant storage silo (from start to finish).</td>
</tr>
<tr>
<td>10</td>
<td>Carbon monoxide emissions from stationary sources.</td>
</tr>
<tr>
<td>12</td>
<td>Determination of inorganic lead emissions from stationary sources.</td>
</tr>
<tr>
<td>15A or 15B</td>
<td>Fluoride emissions from stationary sources.</td>
</tr>
<tr>
<td>15 or 25</td>
<td>Volatile organic compounds concentration.</td>
</tr>
<tr>
<td>161A</td>
<td>Determination of particulate and gaseous mercury emissions.</td>
</tr>
<tr>
<td>164</td>
<td>Determination of beryllium emissions from stationary sources.</td>
</tr>
<tr>
<td>165</td>
<td>Determination of particulate and gaseous arsenic emissions.</td>
</tr>
</tbody>
</table>
PERMITTEE: Okeelanta Power Limited Partnership

Permit Number: AC50-219413
Expiration Date: July 1, 1996

SPECIFIC CONDITIONS:

EMTIC Test Method
Chromium and copper emissions.

CTM-012.WPP

"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.

23. 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, NOx, SO2, 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, NOx, CO, VOC, mercury, arsenic, chromium, copper and visible emissions.
- Once every five years (at permit renewal time) for SO2, 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 30 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.

17. 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 ___ day of September, 1993

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

[Signature]
Virginia B. Watherall, 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.

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 Stormer, PBCHD
Mr. James Meriwether, Okeelanta  Mr. Ron Blackburn, SD
Mr. Matthew Capone, Okeelanta  Mr. Gregg Worley, EPA Region 4
Mr. David Buff, Golder Associates  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  February 1, 2002
(Clerk)  (Date)
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

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

"More Protection, Less Process"
SECTION I. GENERAL INFORMATION

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:

<table>
<thead>
<tr>
<th>ID</th>
<th>Emission Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>001</td>
<td>Cogeneration Boiler A (715 MMBtu per hour)</td>
</tr>
<tr>
<td>002</td>
<td>Cogeneration Boiler B (715 MMBtu per hour)</td>
</tr>
<tr>
<td>003</td>
<td>Cogeneration Boiler C (715 MMBtu per hour)</td>
</tr>
<tr>
<td>004</td>
<td>Material handling and storage</td>
</tr>
</tbody>
</table>

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/PM10), sulfur dioxide (SO2), 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.
SECTION I. GENERAL INFORMATION

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.
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 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.]
SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

This section of the permit addresses the following emissions units.

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

**Description:** Each unit is a biomass-fired spreader stoker steam boiler manufactured by Zurn and designed to produce approximately 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.
SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

- 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 (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.

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 SO₂ emissions and the 12-month rolling total SO₂ 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:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Emissions Standards Per Boiler¹</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>lb/MMBtu</td>
<td>lb/hr</td>
</tr>
<tr>
<td>Carbon Monoxide (CO)</td>
<td>30-day rolling CEMS avg.</td>
<td>0.50</td>
</tr>
<tr>
<td></td>
<td>12-month rolling CEMS avg.</td>
<td>0.55</td>
</tr>
<tr>
<td>Nitrogen Oxides (NOx)</td>
<td>30-day rolling CEMS avg.</td>
<td>0.15</td>
</tr>
<tr>
<td>Sulphur Dioxide (SO₂)</td>
<td>24-hour rolling CEMS avg.</td>
<td>0.20</td>
</tr>
<tr>
<td></td>
<td>30-day rolling CEMS avg.</td>
<td>0.10</td>
</tr>
<tr>
<td></td>
<td>12-month rolling CEMS avg.</td>
<td>0.06</td>
</tr>
<tr>
<td>Stack Opacity (Alternative: EPA Method 9)</td>
<td>6-minute block COMS avg.</td>
<td>≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity</td>
</tr>
<tr>
<td>Particulate Matter (PM/PM10)</td>
<td>3-run test avg.</td>
<td>0.03</td>
</tr>
<tr>
<td>Volatile Organic Compounds (VOC)</td>
<td>3-run test avg.</td>
<td>0.06</td>
</tr>
<tr>
<td>Lead</td>
<td>3-run test avg.</td>
<td>1.5 x 10⁻⁶</td>
</tr>
<tr>
<td>Mercury</td>
<td>3-run test avg.</td>
<td>5.4 x 10⁻⁶</td>
</tr>
</tbody>
</table>
SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

a. Compliance shall be determined by data collected from the required CO CEMS in terms of “lb/MMBtu of heat input”. The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and be consistent with the 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 $1.9 \times 10^{-3}$ 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.
SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

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 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]

**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
SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

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).

<table>
<thead>
<tr>
<th>EPA Method*</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Selection of sample site and velocity traverses</td>
</tr>
<tr>
<td>2</td>
<td>Stack gas flow rate when converting concentrations to or from mass emission limits</td>
</tr>
<tr>
<td>3A</td>
<td>Gas analysis when needed for calculation of molecular weight or percent O2</td>
</tr>
<tr>
<td>4</td>
<td>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</td>
</tr>
<tr>
<td>5</td>
<td>Particulate matter emissions</td>
</tr>
<tr>
<td>6 or 6C</td>
<td>Sulfur dioxide emissions</td>
</tr>
<tr>
<td>7 or 7E</td>
<td>Nitrogen oxide emissions</td>
</tr>
</tbody>
</table>
| 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 1B 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]

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.

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.]
Appendix A. Citation Format
Appendix B. General Conditions
Appendix C. Standard Requirements
Appendix D. Final BACT Determinations
Appendix E. Continuous Monitor Requirements
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
“AQ” 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.
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.
SECTION IV. APPENDIX C
STANDARD REQUIREMENTS

[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 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
SECTION IV. APPENDIX C
STANDARD REQUIREMENTS

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.]
SECTION IV. APPENDIX D

FINAL BACT DETERMINATIONS

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 (SO2)

*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:* SO2 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 SO2 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 SO2 emissions. However, actual SO2 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 SO2 emissions with the firing of low sulfur fuels.
SECTION IV. APPENDIX D
FINAL BACT DETERMINATIONS

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

(Date)

Recommended By:

C. H. Fancy, Chief
Bureau of Air Regulation

(Date)

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

(Date)
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 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 (O2), sulfur dioxide (SO2), 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 SO2 CEMS shall comply with Performance Specification 2 in Appendix B of 40 CFR 60. The SO2 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) O2 CEMS shall comply with Performance Specification 3 in Appendix B of 40 CFR 60. The O2 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-
SECTION IV. APPENDIX E  
CONTINUOUS MONITOR REQUIREMENTS

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 SO2 CEMS shall express the 1-hour emission averages in terms of “lb/MMBtu of heat input”. O2 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

<table>
<thead>
<tr>
<th>Facility Name</th>
<th>ARMS ID No.</th>
<th>Title V Air Permit No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Okeelanta Cogeneration Plant</td>
<td>0990332</td>
<td></td>
</tr>
</tbody>
</table>

**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**
Spreaderg stoker boiler with maximum heat input of 715 MMBtu/hour
ARMSEU 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, 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 ___ SO2 ___ 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]

**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.
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 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

"More Protection, Less Process"

Printed on recycled paper.
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 5/14/01 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 Haynes, 5/14/01
(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-196M): OkPLP requested modification of the CO and SO2 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(0)
Okeelanta Cogeneration Plant
Increased Heat Input Rates
Palm Beach County, Florida

Enclosed is Final Air Permit No. PSD-FL-196(0), 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 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

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

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 x 10^-6 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.
SECTION I. GENERAL INFORMATION

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.

<table>
<thead>
<tr>
<th>ID</th>
<th>Emission Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>001</td>
<td>Cogeneration Boiler A (760 MMBtu per hour)</td>
</tr>
<tr>
<td>002</td>
<td>Cogeneration Boiler B (760 MMBtu per hour)</td>
</tr>
<tr>
<td>003</td>
<td>Cogeneration Boiler C (760 MMBtu per hour)</td>
</tr>
<tr>
<td>004</td>
<td>Material handling and storage</td>
</tr>
</tbody>
</table>

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

This section of the permit addresses the following emissions units.

<table>
<thead>
<tr>
<th>Emissions Units 001, 002, and 003: Cogeneration Boilers A, B, and C</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Description:</strong> 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.</td>
</tr>
<tr>
<td><strong>Fuels and Capacity:</strong> 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).</td>
</tr>
<tr>
<td><strong>Controls:</strong> 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.</td>
</tr>
<tr>
<td><strong>Stack Parameters:</strong> 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.</td>
</tr>
</tbody>
</table>

| 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.

New Hope Power Partnership
Okeelanta Cogeneration Plant, Increased Heat Input

Page 5 of 13

Project No. 0990332-016-AC
Air Permit No. PSD-FL-196(O)
SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

- 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 (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.

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 as 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\textsubscript{2} emissions and the 12-month rolling total SO\textsubscript{2} emissions shall be determined and kept in a log.

15. **Permanant 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:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Emissions Standards per Boiler(^1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon Monoxide (CO)</td>
<td>30-day rolling CEMS avg.</td>
<td>0.50 (\text{lb/MMBtu})</td>
</tr>
<tr>
<td></td>
<td>12-month rolling CEMS avg.</td>
<td>0.35 (\text{lb/MMBtu})</td>
</tr>
<tr>
<td>Nitrogen Oxides (NO\textsubscript{x})</td>
<td>30-day rolling CEMS avg.</td>
<td>0.15 (\text{lb/MMBtu})</td>
</tr>
<tr>
<td>Sulfur Dioxide (SO\textsubscript{2})</td>
<td>24-hour rolling CEMS avg.</td>
<td>0.20 (\text{lb/MMBtu})</td>
</tr>
<tr>
<td></td>
<td>30-day rolling CEMS avg.</td>
<td>0.10 (\text{lb/MMBtu})</td>
</tr>
<tr>
<td></td>
<td>12-month rolling CEMS avg.</td>
<td>0.06 (\text{lb/MMBtu})</td>
</tr>
<tr>
<td>Stack Opacity(^d)</td>
<td>6-minute block COMS avg.</td>
<td>(\leq 20%) opacity, except for one 6-minute block per hour that is (\leq 27%) opacity</td>
</tr>
<tr>
<td>Particulate Matter (PM/PM\textsubscript{10})(^e)</td>
<td>3-run test avg.</td>
<td>0.026 (\text{lb/MMBtu})</td>
</tr>
<tr>
<td>Volatile Organic Compounds (VOC)(^f)</td>
<td>3-run test avg.</td>
<td>0.05 (\text{lb/MMBtu})</td>
</tr>
<tr>
<td>Mercury(^g)</td>
<td>3-run test avg.</td>
<td>(5.4 \times 10^{-6}) (\text{lb/MMBtu})</td>
</tr>
<tr>
<td>Lead and Fluorides(^b)</td>
<td>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.</td>
<td></td>
</tr>
</tbody>
</table>

\(^1\) Emissions standards per boiler are the product of the heat input required by the boiler times the corresponding pollutant emission rate. These emissions standards are in addition to the annual and daily emission limits.

\(^d\) Stack opacity is to be determined using the photographic method. The limit of 20% opacity is for one 6-minute block per hour. The 27% opacity limit is for an annual average.

\(^e\) Particulate matter (PM/PM\textsubscript{10}) emissions are measured in accordance with the protocol described in 40 CFR 60.51 as modified by 40 CFR 60.51a and as amended by 40 CFR 60.51a.

\(^f\) Volatile Organic Compounds (VOC) emissions are measured in accordance with the protocol described in 40 CFR 60.51 as modified by 40 CFR 60.51a and as amended by 40 CFR 60.51a.

\(^g\) Mercury emissions are measured in accordance with the protocol described in 40 CFR 60.51 as modified by 40 CFR 60.51a and as amended by 40 CFR 60.51a.

\(^b\) Lead and Fluorides emissions are measured in accordance with the protocol described in 40 CFR 60.51 as modified by 40 CFR 60.51a and as amended by 40 CFR 60.51a.

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New Hope Power Partnership  
Okeelanta Cogeneration Plant, Increased Heat Input  
Page 8 of 13

Project No. 0990332-016-AC  
Air Permit No. PSD-FL-196(O)
SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

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 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 x 10^-5 lb/MMBtu and average fluoride emissions are expected to be 1.9 x 10^-4 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
SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

(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 cogen boiler.

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 cogen 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 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]

c. *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).

<table>
<thead>
<tr>
<th>EPA Method</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Selection of sample site and velocity traverses</td>
</tr>
<tr>
<td>2</td>
<td>Stack gas flow rate when converting concentrations to or from mass emission limits</td>
</tr>
<tr>
<td>3A</td>
<td>Gas analysis when needed for calculation of molecular weight or percent O2</td>
</tr>
<tr>
<td>4</td>
<td>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</td>
</tr>
<tr>
<td>5</td>
<td>Particulate matter emissions</td>
</tr>
<tr>
<td>6 or 6C</td>
<td>Sulfur dioxide emissions</td>
</tr>
<tr>
<td>7 or 7E</td>
<td>Nitrogen oxide emissions</td>
</tr>
</tbody>
</table>
| 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 SO2. [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 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.

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 “ppmv corrected to 3% oxygen based on a 24-hour average (day)” for each operational day. [Rule 62-210.370(2), F.A.C.]
SECTION IV. APPENDICES

CONTENTS

Appendix A. Citation Format
Appendix B. General Conditions
Appendix C. Standard Requirements
Appendix D. Final BACT Determinations
Appendix E. Continuous Monitor Requirements
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.
SECTION IV. APPENDIX B
GENERAL CONDITIONS

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.
SECTION IV. APPENDIX C
STANDARD REQUIREMENTS

(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.
SECTION IV. APPENDIX C
STANDARD REQUIREMENTS

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.]
SECTION IV. APPENDIX D
FINAL BACT DETERMINATIONS

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.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>BACT Standards for Each Cogeneration Boiler</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Averaging Period</td>
</tr>
<tr>
<td>Carbon Monoxide (CO)</td>
<td>30-day rolling CEMS avg.</td>
</tr>
<tr>
<td>Based on “good combustion practices”</td>
<td>12-month rolling CEMS avg.</td>
</tr>
<tr>
<td>Nitrogen Oxides (NOx)</td>
<td>30-day rolling CEMS avg.</td>
</tr>
<tr>
<td>Based on the application of SNCR</td>
<td>24-hour rolling CEMS avg.</td>
</tr>
<tr>
<td>Sulfur Dioxide (SO2)</td>
<td>30-day rolling CEMS avg.</td>
</tr>
<tr>
<td>Based on “low sulfur fuels”. The SO2 standards are also surrogate standards for sulfuric acid mist (SAM) emissions.</td>
<td>12-month rolling CEMS avg.</td>
</tr>
<tr>
<td>Opacity</td>
<td>6-minute block COMS avg. (Alternative: EPA Method 9)</td>
</tr>
<tr>
<td>Particulate Matter (PM)</td>
<td>3-run test avg.</td>
</tr>
<tr>
<td>Based on application of mechanical dust collectors and electrostatic precipitator.</td>
<td>3-run test avg.</td>
</tr>
<tr>
<td>Volatile Organic Compounds (VOC)</td>
<td>Based on “good combustion practices”.</td>
</tr>
<tr>
<td>Lead (Pb) and Fluorides (Fl)</td>
<td>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.</td>
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</tbody>
</table>

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.
SECTION IV. APPENDIX D
FINAL BACT DETERMINATIONS

Determination By:

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

Recommended By:

Trina Vielhauer, Chief
Bureau of Air Regulation

Approved By:

Michael G. Cooke, Director
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 (O2), sulfur dioxide (SO2), 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 SO2 CEMS shall comply with Performance Specification 2 in Appendix B of 40 CFR 60. The SO2 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) O2 CEMS shall comply with Performance Specification 3 in Appendix B of 40 CFR 60. The O2 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.
SECTION IV. APPENDIX E
CONTINUOUS MONITOR REQUIREMENTS

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 SO2 CEMS shall express the 1-hour emission averages in terms of "lb/MMBtu of heat input". O2 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.
## SECTION IV. APPENDIX E
### CONTINUOUS MONITOR REQUIREMENTS

<table>
<thead>
<tr>
<th>Facility Name</th>
<th>ARMS ID No.</th>
<th>Title V Air Permit No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Okeelanta Cogeneration Plant</td>
<td>0990332</td>
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<table>
<thead>
<tr>
<th>Facility Address/Location</th>
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<tbody>
<tr>
<td>Located off U.S. Highway 27 South, approximately six miles south of South Bay in Palm Beach County, Florida</td>
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<table>
<thead>
<tr>
<th>Emissions Unit Description</th>
<th>Unit Operation in Calendar Quarter</th>
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<tbody>
<tr>
<td>Spreader stoker boiler with maximum heat input of 760 MMBtu/hour</td>
<td>B __ C</td>
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<tr>
<td>ARMS EU ID No. A __ Cogeneration Boiler:</td>
<td>____________________ hours</td>
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<thead>
<tr>
<th>Control Equipment</th>
<th>Auxiliary Fuels</th>
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<tbody>
<tr>
<td>Mercury - activated carbon injection; Nitrogen Oxides – low NOx burners and selective non-catalytic reduction (NOx) system; Particulate Matter – mechanical dust collectors and electrostatic precipitators</td>
<td>Pipeline natural gas, Distillate oil (≤ 0.05% sulfur by weight)</td>
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<tr>
<th>Primary Fuel</th>
<th>Pollutant Monitored (Check one.)</th>
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<tr>
<td>Biomass, which includes bagasse from adjacent sugar mill and wood material from</td>
<td>CO, NOx, SO2, Opacity</td>
</tr>
<tr>
<td>area suppliers (clean construction and demolition wood debris, yard trash, land</td>
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<tr>
<td>clearing debris, and other clean cellulose and vegetative matter)</td>
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<tr>
<td>1 2 3 4 for year</td>
<td>lb/MMBtu of heat input, 24-hour rolling average</td>
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<tr>
<td></td>
<td>lb/MMBtu of heat input, 30-day rolling average</td>
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<tr>
<td></td>
<td>lb/MMBtu of heat input, 12-month rolling average</td>
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<tr>
<th>Date of last certification or audit:</th>
<th>≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity</th>
</tr>
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### 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. \( \frac{\text{[Total duration of excess emissions]} \times (100\%)}{\text{[Total source operating time]}} \)

**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. \( \frac{\text{[Total CMS Downtime]} \times (100\%)}{\text{[Total source operating time]}} \)

**Note:** 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
NOTICE OF ADMINISTRATIVELY CORRECTED PERMIT

October 10, 2012

Electronic Mail – Return Receipt Requested

In the Matter of a Request for Administrative Correction:

Jose Gonzalez
Vice President
Okeelanta Corporation
21250 U.S. Highway 27
South Bay, Florida 33493

Project No. 0990005-033-AV
Administrative Correction to Permit No. 0990005-032-AV

Okeelanta Sugar Refinery
Palm Beach County

Enclosed are Administratively Corrected Conditions (revisions) to the Title V Air Operation Permit No. 0990005-032-AV, for the operation of the Okeelanta Corporation (ARMS Facility ID No. 0990005) and New Hope Power Company (ARMS Facility ID No. 0990332), located in Palm Beach county at 21250 U.S. Highway 27, South Bay, Florida. This correction is issued pursuant to Rule 62-210.360, Florida Administrative Code (F.A.C.) and Chapter 403, Florida Statutes (F.S.). This change is made at the applicant’s request dated October 2, 2012 to correct page number 29 of 37 to show control efficiencies for EU 054 and EU 055 to be 99.9 percent for PM and 99.0 percent for PM10. This change also adds the requirement for the boilers to be subject to 40 CFR 63 Subpart DDDDD (Boiler MACT) - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. This corrective action does not alter the effective dates of the existing permit.

The Department of Environmental Protection (Department) will consider the above-noted action final unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S. Mediation under Section 120.573, F.S., will not be available for this proposed action.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) by the Agency Clerk in the Department’s Office of General Counsel, 3900 Commonwealth Boulevard, MS #35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within 14 days of receipt of this notice. Petitions filed by any other person must be filed within 14 days of receipt of this proposed action. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time limit shall constitute a waiver of that person’s right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party)
number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner’s representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner’s substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact.

If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency’s proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency’s proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency’s proposed action.

A petition that does not dispute the material facts upon which the Permitting Authority’s action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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

Any party to this order (permit) has the right to seek judicial review of it under Section 120.68, F.S., by the filing of a Notice of Appeal, under Rule 9.110 of the Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station #35, 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 thirty days from the date this notice is filed with the Clerk of the permitting authority.

Executed in Fort Myers, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Jon M. Iglehart
Director of
District Management

Okeelanta Corporation
Okeelanta Sugar Refinery

Administrative Correction to Title V Air Operation Permit
Project No. 0990005-033-AV
Page 3 of 4
CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Administratively Corrected Permit (including the corrected pages or a link to these documents available electronically on a publicly accessible server, was sent by electronic mail with received receipt requested to the persons listed below:

Mr. Jose Gonzalez Jose_Gonzalez@floridacrystals.com
Mr. David A. Buff, P.E. dbuff@golder.com
Mr. Matthew Capone, Florida Crystals matthew_capone@floridacrystals.com
Mr. James Stormer, Palm Beach County Health Department james_stormer@doh.state.fl.us
Ms. Katy Forney, U.S. EPA Region 4 forney.kathleen@epamail.epa.gov
Ms. Ana Oquendo, EPA Region 4 oquendo.ana@epamail.epa.gov
Ms. Barbara Friday, DEP BAR barbara.friday@dep.state.fl.us (for posting with U.S. EPA, Region 4)

Clerk Stamp

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

October 11, 2012

(Clark) (Date)
The purpose of this permit is to revise the Title V air operation permit (No. 0990005-024-AV and provides Administrative Correction to permit No. 0990005-032-AV) for the facility operated by the Okeelanta Corporation (ARMS ID No. 0990005) and the New Hope Power Company (ARMS ID No. 0990332). Okeelanta Corporation operates an existing sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) and New Hope Power Company operates a cogeneration plant (SIC No. 4911). The existing facility is located in Palm Beach County at 21250 U.S. Highway 27 South, South Bay, Florida. The map coordinates are UTM Zone 17, 524.70 km East and 2939.5 km North (Latitude 26° 34.1’ 00” North / Longitude 80° 45’ 00” West).

This Title V Air Operation Permit is issued under the provisions of Chapter 403, F.S., and Chapters 62-4, 62-210 and 62-213, F.A.C. The above named permittee is hereby authorized to operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the permitting authority in accordance with the terms and conditions of this permit.

Effective Date: October 10, 2012
Renewal Application Due Date: December 3, 2014
Expiration Date: July 16, 2015

Jon M. Iglehart
Director of
District Management
NOTICE OF ADMINISTRATIVELY CORRECTED PERMIT

JMI/CBE/mf

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Administratively Corrected Permit (including the corrected pages or a link to these documents available electronically on a publicly accessible server, was sent by electronic mail with received receipt requested to the persons listed below:

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Mr. Matthew Capone, Florida Crystals matthew_capone@floridacrystals.com
Mr. James Stormer, Palm Beach County Health Department james_stormer@doh.state.fl.us
Ms. Katy Forney, U.S. EPA Region 4 forney.kathleen@epamail.epa.gov
Ms. Ana Oquendo, EPA Region 4 oquendo.ana@epamail.epa.gov
Ms. Barbara Friday, DEP BAR barbara.friday@dep.state.fl.us (for posting with U.S. EPA, Region 4)

Clerk Stamp

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

October 11, 2012

(Clerk) (Date)
Pursuant to the applicant’s request, conditions /requirements contained in permit No. 0990005-032-AV have been corrected as indicated below:

Page 2 of 37 - Added reference to Subpart DDDDD (Boiler MACT) as being applicable

Page 11 of 37 - Added Subpart DDDDD (Boiler MACT) as being applicable

Page 29 of 37 - Corrected the PM control efficiency for EU 054 in the table to 99.9 percent for PM, and 99.0 percent for PM10. Also, the PM control efficiency for EU 055 in the table changed to 99.9 percent for PM, and 99.0 percent for PM10.

Statement of Basis - page 1 of 16 - The Statement of Basis changed to include Subpart DA and Subpart DDDDD.

(Note: The NSPS 40 CFR 60, Subpart DDDDD requirement was included in the Draft/Proposed and Public Notice).
Okeelanta Corporation, Sugar Mill and Refinery  
Facility ID No. 0990005

New Hope Power Company, Okeelanta Cogeneration Plant  
Facility ID No. 0990332

Palm Beach County

Title V Air Operation Permit Revision

Permit No. 0990005-033-AV  
(Revision of Title V Air Operation Permit No. 0990005-024-AV  
and Administrative Correction to Permit No. 0990005-032-AV)

Permitting Authority:  
State of Florida  
Department of Environmental Protection  
Air Resource Management, South District  
2295 Victoria Avenue, Suite 364  
Fort Myers, Florida 33901-2549  
Telephone: (239) 344-5600  
Fax: (850) 412-0590

Compliance Authority:  
Palm Beach County  
Health Department  
800 Clematis Street  
P.O. Box 29  
West Palm Beach, FL 33402-0029  
Telephone: (561) 837-5900  
Fax: (561) 837-5295
TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Placard Page</td>
<td>1</td>
</tr>
<tr>
<td>1. Facility Information</td>
<td></td>
</tr>
<tr>
<td>Facility Description</td>
<td>2</td>
</tr>
<tr>
<td>Regulatory Categories</td>
<td>2</td>
</tr>
<tr>
<td>Regulated Pollutants</td>
<td>2</td>
</tr>
<tr>
<td>Summary of Regulated Emissions Units</td>
<td>3</td>
</tr>
<tr>
<td>2. Facility-wide Conditions</td>
<td></td>
</tr>
<tr>
<td>Permitting and Compliance Authorities</td>
<td>8</td>
</tr>
<tr>
<td>Permit Appendices</td>
<td>8</td>
</tr>
<tr>
<td>Annual Reports and Fees</td>
<td>8</td>
</tr>
<tr>
<td>Emissions and Controls</td>
<td>8</td>
</tr>
<tr>
<td>Administrative Requirements</td>
<td>10</td>
</tr>
<tr>
<td>3. Emissions Units and Conditions</td>
<td></td>
</tr>
<tr>
<td>A. Cogeneration Boilers</td>
<td>11</td>
</tr>
<tr>
<td>B. Cogeneration Plant - Material Handling and Storage</td>
<td>22</td>
</tr>
<tr>
<td>C. Boiler 16 (DELETED)</td>
<td></td>
</tr>
<tr>
<td>D. Sugar Refinery</td>
<td>24</td>
</tr>
<tr>
<td>E. Transshipment Facility</td>
<td>32</td>
</tr>
<tr>
<td>F. Distillate Oil Storage Tanks</td>
<td>34</td>
</tr>
<tr>
<td>G. Paint Spray Booth – Okeelanta Shop</td>
<td>35</td>
</tr>
<tr>
<td>4. Appendices</td>
<td></td>
</tr>
<tr>
<td>Appendix AM. Ash Management Plan</td>
<td>37</td>
</tr>
<tr>
<td>Appendix CF. Citation Format and Glossary</td>
<td></td>
</tr>
<tr>
<td>Appendix CM. Compliance Assurance Monitoring Plan</td>
<td></td>
</tr>
<tr>
<td>Appendix CP. Compliance Plan</td>
<td></td>
</tr>
<tr>
<td>Appendix CT. Common Testing Requirements</td>
<td></td>
</tr>
<tr>
<td>Appendix FM. Fuel Management Plan</td>
<td></td>
</tr>
<tr>
<td>Appendix GC. Good Combustion Plan, Cogeneration Boilers</td>
<td></td>
</tr>
<tr>
<td>Appendix HI. Permit History</td>
<td></td>
</tr>
<tr>
<td>Appendix OM. Operation and Maintenance Plans, Cogeneration Boilers</td>
<td></td>
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<tr>
<td>Appendix QR. Quarterly Report, Cogeneration Boilers</td>
<td></td>
</tr>
<tr>
<td>Appendix SS. Summary of Standards</td>
<td></td>
</tr>
<tr>
<td>Appendix TV. Title V Conditions</td>
<td></td>
</tr>
<tr>
<td>Appendix UI. List of Unregulated Emissions Units and/or Activities</td>
<td></td>
</tr>
<tr>
<td>Appendix 60A. NSPS Subpart A, General Provisions</td>
<td></td>
</tr>
<tr>
<td>Appendix 60Da. NSPS Subpart Da, Electric Utility Steam Generating Units</td>
<td></td>
</tr>
<tr>
<td>Appendix 60Db. NSPS Subpart Db, Industrial Boilers and Process Heaters</td>
<td></td>
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<tr>
<td>Appendix 60Ea. NSPS Subpart Ea, Applicability for Municipal Waste Combustors</td>
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<tr>
<td>Appendix 60DDDD. NSPS Subpart DDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters</td>
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The purpose of this permit is to revise the Title V air operation permit (No. 0990005-024-AV and provides Administrative Correction to permit No. 0990005-032-AV) for the facility operated by the Okeelanta Corporation (ARMS ID No. 0990005) and the New Hope Power Company (ARMS ID No. 0990332). Okeelanta Corporation operates an existing sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) and New Hope Power Company operates a cogeneration plant (SIC No. 4911). The existing facility is located in Palm Beach County at 21250 U.S. Highway 27 South, South Bay, Florida. The map coordinates are UTM Zone 17, 524.70 km East and 2939.5 km North (Latitude 26° 34.1’ 00” North / Longitude 80° 45’ 00” West).

This Title V Air Operation Permit is issued under the provisions of Chapter 403, F.S., and Chapters 62-4, 62-210 and 62-213, F.A.C. The above named permittee is hereby authorized to operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the permitting authority in accordance with the terms and conditions of this permit.

Effective Date: October 10, 2012
Renewal Application Due Date: December 3, 2014
Expiration Date: July 16, 2015

___________________________
Jon M. Iglehart
Director of
District Management
FACILITY DESCRIPTION

The facility consists of two adjacent plants. Okeelanta Corporation (ARMS ID No. 0990005) operates an existing sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) including sugar packaging and transshipment activities. New Hope Power Company (ARMS ID No. 0990332) operates an existing cogeneration plant that provides process steam for the sugar mill and refinery operations as well as generating electricity for sale to the power grid (SIC 4911). The cogeneration plant, sugar mill, and sugar refinery are all considered a single facility for purposes of the PSD and Title V regulatory programs.

The primary sources of air pollution include: three 760 MMBtu per hour cogeneration boilers; transfer and storage of wood chip and bagasse fuels; distillate oil storage tanks; transfer and storage of sugar; and a paint spray booth. The facility includes other miscellaneous unregulated emissions units and activities.

REGULATORY CATEGORIES

- The facility is a major source of hazardous air pollutants.
- The facility does not operate any units subject to the Title IV acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The facility is a major stationary source of air pollution in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.
- The facility is subject to Chapter 62-17, F.A.C. for power plant site certification because it produces more than 75 MW of steam-generated electrical power. [Site Certification No. PA 04-46]
- Existing units are subject to the following New Source Performance Standards (NSPS) in Part 60 of Title 40, the Code of Federal Regulations (CFR): Subpart A (General Provisions), NSPS Part 60, Subpart Da (Electric Utility Steam Generating Units) and Subpart Db (Industrial-Commercial-Institutional Steam Generating Units).
- Units are subject to National Emissions Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 63 Subpart A General Provisions.
- Units are subject to National Emissions Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 63 Subpart A – General Provisions.

REGULATED POLLUTANTS

Criteria Pollutants

Emissions units at this facility may emit one or more of the following criteria air pollutants: carbon monoxide (CO), nitrogen oxides (NOX), sulfur dioxide (SO2), particulate matter (PM); particulate matter with a mean particle diameter of 10 microns or less (PM10), volatile organic compounds (VOC) and lead (Pb).

Other Regulated PSD Pollutants

In addition to the above criteria air pollutants, emissions units at this facility may emit one or more of the following PSD pollutants: fluorides (F); sulfuric acid mist (SAM); hydrogen sulfide (H2S); total reduced sulfur (TRS), including H2S; reduced sulfur compounds, including H2S; and mercury (Hg).

Hazardous Air Pollutants

Emissions units at this facility may emit one or more hazardous air pollutants (HAP) as defined in Rule 62-210.200, F.A.C.
**SUMMARY OF REGULATED EMISSIONS UNITS**

Please refer to the appropriate Permit No., Facility ID No. and Emissions Unit No. on all correspondence, test report submittals, applications, etc.

**ARMS ID No. 0990005 – Okeelanta Corporation**

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
<th>Process Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>014</td>
<td>Boiler No. 16 (DELETED)</td>
<td>Sugar Mill and Refinery</td>
</tr>
<tr>
<td>018</td>
<td>Central Vacuum System (listed as insignificant unit)</td>
<td>Transshipment Facility</td>
</tr>
<tr>
<td>019</td>
<td>Sugar Packaging Lines 0-9, including 8A and 8B</td>
<td>Transshipment Facility</td>
</tr>
<tr>
<td>020</td>
<td>Sugar Grinder/Hopper</td>
<td>Transshipment Facility</td>
</tr>
<tr>
<td>021</td>
<td>Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1</td>
<td>Sugar Refinery</td>
</tr>
<tr>
<td>022</td>
<td>Central Dust Collection System No. 2 with Roto-clone (No.2) “B” System</td>
<td>Sugar Refinery</td>
</tr>
<tr>
<td>023</td>
<td>Cooler No. 1 with Roto-clone No. 3</td>
<td>Sugar Refinery</td>
</tr>
<tr>
<td>024</td>
<td>Cooler No. 2 with Roto-clone No. 4</td>
<td>Sugar Refinery</td>
</tr>
<tr>
<td>025</td>
<td>Fluidized Bed Dryer/Cooler with Baghouse</td>
<td>Sugar Refinery</td>
</tr>
<tr>
<td>030</td>
<td>Sugar Silos Nos. 1, 2, and 3</td>
<td>Transshipment Facility</td>
</tr>
<tr>
<td>031</td>
<td>Railcar Sugar Unloading Receiver 1</td>
<td>Transshipment Facility</td>
</tr>
<tr>
<td>032</td>
<td>Railcar Sugar Unloading Receiver 2</td>
<td>Transshipment Facility</td>
</tr>
<tr>
<td>034</td>
<td>Bulk Load-Out Operation</td>
<td>Sugar Refinery</td>
</tr>
<tr>
<td>035</td>
<td>Transfer Bulk Load-Out Operation</td>
<td>Sugar Refinery</td>
</tr>
<tr>
<td>043</td>
<td>Sugar Refinery Alcohol Usage</td>
<td>Sugar Refinery</td>
</tr>
<tr>
<td>045</td>
<td>Powdered Sugar Dryer/Cooler, Packaging Line 8A And 8B</td>
<td>Transshipment Facility</td>
</tr>
<tr>
<td>046</td>
<td>Powdered Sugar Hopper</td>
<td>Transshipment Facility</td>
</tr>
<tr>
<td>047</td>
<td>Sugar Packaging Lines 12 and 13</td>
<td>Transshipment Facility</td>
</tr>
<tr>
<td>048</td>
<td>Paint Booth</td>
<td>Okeelanta Shop</td>
</tr>
<tr>
<td>049</td>
<td>Sugar Packaging Line 14</td>
<td>Transshipment Facility</td>
</tr>
<tr>
<td>054</td>
<td>“A” System - Wet Roto-clone (No. 6)</td>
<td>Sugar Refinery</td>
</tr>
<tr>
<td>055</td>
<td>“C” System - Wet Roto-clone (No. 7)</td>
<td>Sugar Refinery</td>
</tr>
</tbody>
</table>

(Permitting Note: The original sugar mill boilers (EU-001 - EU-013) and Boiler No. 16 (EU-014) have been permanently shutdown.)

**ARMS ID No. 0990332 – New Hope Power Company**

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
<th>Process Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>001</td>
<td>Cogeneration Boiler A</td>
<td>Cogeneration Plant</td>
</tr>
<tr>
<td>002</td>
<td>Cogeneration Boiler B</td>
<td>Cogeneration Plant</td>
</tr>
<tr>
<td>003</td>
<td>Cogeneration Boiler C</td>
<td>Cogeneration Plant</td>
</tr>
<tr>
<td>004</td>
<td>Cogeneration Plant - Material Handling and Storage</td>
<td>Cogeneration Plant</td>
</tr>
</tbody>
</table>

**Unregulated Emissions Units and/or Activities**

**ARMS ID No. 0990005 – Okeelanta Corporation**
### SECTION 1. FACILITY INFORMATION

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
<th>Process Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>015</td>
<td>Fuel Storage Tank (Deleted)</td>
<td>Sugar Mill and Refinery</td>
</tr>
<tr>
<td>016</td>
<td>Fuel Storage Tank (Deleted)</td>
<td>Sugar Mill and Refinery</td>
</tr>
<tr>
<td>017</td>
<td>Fuel Storage Tank (Deleted)</td>
<td>Sugar Mill and Refinery</td>
</tr>
<tr>
<td>033</td>
<td>Sugar Refinery Miscellaneous Support Equipment</td>
<td>Sugar Refinery</td>
</tr>
<tr>
<td>036</td>
<td>Shop Operations</td>
<td>Sugar Mill</td>
</tr>
<tr>
<td>037</td>
<td>Sugar Mill Boiler House</td>
<td>Sugar Mill</td>
</tr>
<tr>
<td>038</td>
<td>Sugarcane Dumping Area</td>
<td>Sugar Mill</td>
</tr>
<tr>
<td>039</td>
<td>Sugarcane Processing Facility</td>
<td>Sugar Mill</td>
</tr>
<tr>
<td>040</td>
<td>Fuel Tank Farm</td>
<td>Facility</td>
</tr>
<tr>
<td>041</td>
<td>Potable Water System</td>
<td>Facility</td>
</tr>
<tr>
<td>042</td>
<td>Sewer Plant</td>
<td>Facility</td>
</tr>
<tr>
<td>044</td>
<td>Okeelanta Facility - Miscellaneous Unregulated Activities</td>
<td>Okeelanta Facility</td>
</tr>
<tr>
<td>050</td>
<td>Transshipment Facility, Miscellaneous Support Equipment</td>
<td>Transshipment Facility</td>
</tr>
</tbody>
</table>

**ARMS ID No. 0990332 – New Hope Power Company**

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
<th>Process Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>005</td>
<td>Cogeneration Plant – Miscellaneous Support Equipment</td>
<td>Cogeneration Plant</td>
</tr>
</tbody>
</table>

Unregulated and insignificant emissions units and activities: (Also summarized in Appendix UI in Section 4 of this permit).

**Okeelanta Corporation Sugar Mill and Refinery (ARMS ID No. 0990005)**

<table>
<thead>
<tr>
<th>ID No.</th>
<th>EU Description</th>
<th>Activities/Equipment</th>
</tr>
</thead>
<tbody>
<tr>
<td>033</td>
<td>Sugar Refinery Miscellaneous Support Equipment</td>
<td>• Bagging Machines</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Bulk Curing, Wet Sugar and Portable Overflow Bins</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Centrifugals</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• De-Sweeteners</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Evaporators and Condensers</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Large and Small Heaters</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Primary and Secondary Filters</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Refined Sugar Handling, Storage Silo, and Sugar/Syrup Mixer</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Rotex Screens</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Silo Scale</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Sugar Refinery Process Tanks (Blackwater, Clarifier, Liquor, Melted Sugar Storage, Melter, Mixer, Reactor, Scums, Secondary Treatment, Sweetwater, Syrup Storage Tanks, and Phosphoric Acid Storage and Distribution System</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Vacuum Pans with Condenser and non-Condensible Gas Vent</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Isopropyl Alcohol Stored in Drums</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Powdered Carbon Mixing Room</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Refined Sugar Dust Collectors (Vented Inside Building)</td>
</tr>
<tr>
<td>036</td>
<td>Shop Activities</td>
<td>• Surface Coating Operations (Non-R ACT Vehicle Painting)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Diesel Engine – Portable Air Compressor</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Vehicle Repair (Body Shop)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Crawlers Repair Shop</td>
</tr>
</tbody>
</table>
### SECTION 1. FACILITY INFORMATION

<table>
<thead>
<tr>
<th>ID No.</th>
<th>EU Description</th>
<th>Activities/Equipment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>- Hydraulic Oil, Mineral Spirits, and Waste/Used Oil Storage Tanks</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Mechanics’ Trucks With Portable Air Compressors (Gasoline Engines)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Portable Pressure Cleaners (Gasoline Engines)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Steam Clean Station</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Truck, Trailer, Service Vehicles, Wheel Tractor Repair Shops</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Cold Cleaning Devices (parts washer)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Containers for Oil/Grease/Used Oil</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Oil/Water Separator/Skimmer Equipment</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Portable Welders</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Pressurized LPG Tanks</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Stationary IC Engines</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Vacuum Cleaning Systems</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Vehicle Generated Dust</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Woodworking and Metal Working Operations</td>
</tr>
<tr>
<td>037</td>
<td>Sugar Mill Boiler House</td>
<td>- Boiler Blowdown Pipes &amp; Vents</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Boiler Water Chemical Prep Tanks</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Boiler WaterDearator and Tank</td>
</tr>
<tr>
<td>038</td>
<td>Sugar Mill Cane Dumping Area</td>
<td>- Cane Dumping, Handling, and Storage Cane Knives, Shredding, and Conveying</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Steam Clean Station</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Oil/Water Separator/Skimmer</td>
</tr>
<tr>
<td>039</td>
<td>Sugarcane Processing Facility</td>
<td>- Bagacillo Cyclone and Handling Systems</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Batch Mixers (&lt;30 Cu. Ft.)</td>
</tr>
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<td></td>
<td>- Carbonaceous Fuel Conveying, Handling, and Storage Piles</td>
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<td></td>
<td>- Cold Cleaning Devices (Non-Halogenated Solvent)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Containers For Oils/Wax/Grease</td>
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<tr>
<td></td>
<td></td>
<td>- Cooling Water Towers, Spray Ponds and Canals</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Covered Conveyors/Drop Points</td>
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<tr>
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<td></td>
<td>- Diesel, Gasoline, Fuel Oil, Kerosene, Lube Oil, Waste and Used Oil Tanks</td>
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<tr>
<td></td>
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<td>- Electric Ovens For Drying</td>
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<tr>
<td></td>
<td></td>
<td>- Emergency Generators</td>
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<tr>
<td></td>
<td></td>
<td>- Gear Boxes, Reducers Vents</td>
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<td>- Ground Water Remediation Stripping Tower</td>
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<tr>
<td></td>
<td></td>
<td>- Handling Of Raw Sugar</td>
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<tr>
<td></td>
<td></td>
<td>- Industrial Waste Water Tanks (Non-MACT)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Molasses Storage Tanks</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Mud Ponds</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Oil/Water Seperator/Skimmer Equipment</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Painting Operations</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Portable Diesel Air Compressors</td>
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<tr>
<td></td>
<td></td>
<td>- Portable Electric Generators</td>
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<td></td>
<td></td>
<td>- Portable Welders</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Pressurized LPG Tanks</td>
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<tr>
<td></td>
<td></td>
<td>- Process Water Filtration Intake Screens</td>
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<tr>
<td></td>
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<td>- Process Wide Flanges and Valves</td>
</tr>
<tr>
<td></td>
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<td>- Pump Operations</td>
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<td></td>
<td></td>
<td>- Scrubber Water Ponds and Troughs</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Stationary Internal Combustion Engines (General)</td>
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<tr>
<td></td>
<td></td>
<td>- Vacuum Cleaning Systems</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Vehicle Generated Dust</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Vents From Hydraulic/Lube Oil Reservoirs</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Woodworking and Metal Working Operations</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Centrifugals With Mixers</td>
</tr>
</tbody>
</table>
### SECTION 1. FACILITY INFORMATION

<table>
<thead>
<tr>
<th>ID No.</th>
<th>EU Description</th>
<th>Activities/Equipment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>- Crystallizers/Receivers</td>
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<tr>
<td></td>
<td></td>
<td>- Evaporator Cleaning Operations</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Evaporators (W/ Non-Condensable Gas Vent)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Juice Heaters</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Mud Filter Condensers Vacuum Pumps</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- <strong>Process Tanks</strong> <em>(Batch, Clarified Juice, Coagulant Mix, Flash, Liming, Mingler, Mixer, Mud Mixing, Pan Feed, Magma, Mud Waste, Muriatic, Sugar Receiver, and Syrup Storage)</em></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- <strong>Isopropyl alcohol stored in drums</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Isopropyl alcohol usage in vacuum pans</td>
</tr>
<tr>
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<td></td>
<td>- Rotary Vacuum Filters</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Vacuum Pans with NCG vents, Condensers, And Pumps</td>
</tr>
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<td></td>
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<td>- Lime Storage Silo and Distribution Systems</td>
</tr>
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<td>- Lime Silo Baghouse (5% Opacity)</td>
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<td></td>
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<td>- Diesel Engines for Operation of IWW Pumps</td>
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<td>- Phosphoric Acid Storage and Distribution Systems</td>
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<td>- Sodium Hydroxide Storage and Distribution Systems</td>
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<td>- Mill Crown Wheel Removal Operations</td>
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<td>- Vertical Molasses Crystalizer</td>
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<td>- Cane Mills</td>
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<td>- Cush-cush Screens/Conveyors and DSM Screens</td>
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<td>- Hydrochloric Acid Tanks</td>
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<td>- Mill Turbines with Vents</td>
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<td>- Carbon Slurry Tank</td>
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<td>- Condensate Tank</td>
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<td>Facility Fuel Tank Farm</td>
<td>- Diesel, Gasoline and Oil Tanks</td>
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<td>- Diesel and Gasoline Pumps and Loading Arms</td>
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<td>- Oil/Water Separator/Skimmer Equipment</td>
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<td>Facility Potable Water System</td>
<td>- Hydrogen Sulfide Degasifiers</td>
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<td>- Membrane Cleaning Chemicals and Process Water Discharge Canal</td>
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<td>- Sulfuric Acid Storage and Distribution Systems</td>
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<td>- Disinfection System</td>
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<td>Facility Sewer Plant</td>
<td>- Sewage Treatment Plant</td>
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<td></td>
<td></td>
<td>- Collection and Distribution Lift Station</td>
</tr>
<tr>
<td></td>
<td>Okeelanta Facility - Miscellaneous</td>
<td>- Forklift and crane operations</td>
</tr>
<tr>
<td></td>
<td>Unregulated Activities</td>
<td>- Bagasse conveying to cogeneration boilers or biomass storage</td>
</tr>
<tr>
<td></td>
<td>Transshipment Facility, Miscellaneous</td>
<td>Containers for Oil/Grease/Ink</td>
</tr>
<tr>
<td></td>
<td>Support Equipment</td>
<td>- Diesel Fire Pump Engine</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Diesel Tank</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Vehicle Generated Dust</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Refined Sugar Dust Collectors (Vented Inside Building)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Portable Vacuum Cleaners</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Propane-Fired Water Heaters for Disinfection Process Vessels</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Steam Clean Station</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Cold Cleaning Devices (Parts Washer)</td>
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</tbody>
</table>
SECTION 1. FACILITY INFORMATION

The following activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

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<thead>
<tr>
<th>Code</th>
<th>Activity Description</th>
<th>Location</th>
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<tbody>
<tr>
<td>056</td>
<td>Hi-Vac Industrial Vacuum System</td>
<td>Sugar Mill &amp; Refinery</td>
</tr>
<tr>
<td>053</td>
<td>Printing Operation</td>
<td>Trans-shipment</td>
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The following emission units have been determined by the Department to be EXEMPT from permitting.

<table>
<thead>
<tr>
<th>Code</th>
<th>Activity Description</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>056</td>
<td>Hi-Vac Industrial Vacuum System</td>
<td>Sugar Mill &amp; Refinery</td>
</tr>
<tr>
<td>057</td>
<td>Speciality Sugar Product</td>
<td>300 hp gas-fired package boiler</td>
</tr>
<tr>
<td>058</td>
<td>Sugar Bin with Dust Collector</td>
<td>(Refined Sugar Warehouse No. 3)</td>
</tr>
<tr>
<td>052</td>
<td>Bulk Transfer Station</td>
<td>Wet Roto-clone No. 5</td>
</tr>
<tr>
<td>051</td>
<td>Refined Sugar Silo</td>
<td>Baghouse</td>
</tr>
<tr>
<td>029</td>
<td>Packaging Line 10</td>
<td>Baghouse (Located in Sugar Refinery)</td>
</tr>
</tbody>
</table>

Exemptions for temporary jaw crushers:

Exemption permit No. 0990005-028-AC (dated June 17, 2011) and permit No. 0990005-031 (dated December 15, 2011) were issued for temporary jaw crushers, operated by third party, for short term operation pertaining to demolishing of the old carpenter shop and three adjacent concrete slabs. This temporary operation has been completed and these exemptions are no longer applicable.
SECTION 2. FACILITY-WIDE CONDITIONS

Unless otherwise specified by the permit, the following conditions apply facility-wide to all emission units and activities:

PERMITTING AND COMPLIANCE AUTHORITIES

1. Permitting Authority: The Department’s Bureau of Air Regulation is the permitting authority for this renewal permit. The permitting authority for subsequent revisions and renewals is the Air Resource Section of the Department’s South District Office at: 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33901-2549. The telephone number is (239) 344-5600 and the fax number is (850) 412-0590. Copies shall be sent to each agency identified under Compliance Authority.

2. Compliance Authority: The permittee shall submit all compliance related notifications and reports required of this permit to the Air & Waste Section, Division of Environmental Public Health (4th Floor) of the Palm Beach County Health Department at P.O. Box 29, West Palm Beach, Florida 33402-0029. The telephone number is (561) 837-5900 and the fax number is (561) 837-5295. Copies of all such documents shall be submitted to the Air Resources Section of the Department’s South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33901-2549. The telephone number is (239) 344-5600 and the fax number is (850) 412-0590.

PERMIT APPENDICES

3. Appendices: The appendices identified as Section 4 in the Table of Contents are attached as an enforceable part of this permit unless otherwise indicated.

ANNUAL REPORTS AND FEES

4. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility in accordance with the requirements in Rule 62-210.370, F.A.C. Annual operating reports shall be submitted to the Compliance Authority by April 1st of each year. (Ref. electronic submission to DEP/Tallahassee as specified in Rule 62-210.370(3), F.A.C.

5. Annual Emissions Fee Form and Fee: The annual Title V emissions fees are due (postmarked) by March 1st of each year. The completed form and calculated fee shall be submitted to: Major Air Pollution Source Annual Emissions Fee, P.O. Box 3070, Tallahassee, Florida 32315-3070. The forms are available for download by accessing the Title V Annual Emissions Fee On-line Information Center at the following Internet web site: http://www.dep.state.fl.us/air/emission/tvfee.htm [Rule 62-213.205, F.A.C.]

EMISSIONS AND CONTROLS

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

7. General VOC and OS Emission Limiting Standards: The permittee shall not 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. Nothing was deemed necessary and ordered on a facility-wide basis. [Rule 62-296.320(1)(a), F.A.C.]

8. General Visible Emissions: Unless otherwise specified by this permit, 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. If the presence of uncombined water is the only reason for failure to meet visible emission standards given in this rule, such failure shall not be a violation of this rule. All visible emissions tests performed pursuant to this rule shall be conducted in accordance with EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C. Test procedures shall meet all
SECTION 2. FACILITY-WIDE CONDITIONS

applicable requirements of Chapter 62-297, F.A.C. This permit condition does not impose any periodic testing requirement. [Rule 62-296.320(4) (b)1, F.A.C.]

9. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An “objectionable odor” means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(Definitions), F.A.C.; and Permit PSD-FL-333]

10. Unconfined Particulate Emissions: This permit requires the use of fans, filters, pneumatic unloading/loading, ductwork, storage silos and other similar equipment to contain, capture, and/or control particulate matter related to the storage and handling of fuels, raw materials and products. The permittee shall also take the following reasonable precautions to prevent fugitive particulate matter emissions from any activity, including: vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling of fuels, raw materials or products.
   a. Where practicable, enclose or cover conveyor systems.
   b. Minimize drop distances of dry materials when handling.
   c. As necessary, provide wind breaks around material handling equipment.
   d. Where possible, confine abrasive blasting.
   e. As necessary, paving and maintenance of roads, parking areas and yards.
   f. As necessary, use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.
   g. As necessary, provide landscape and/or vegetation.
   h. As necessary, remove dust from roads, work areas, parking areas, and other paved areas under the control of the permittee to prevent fugitive dust emissions.
   i. As necessary, apply water or other dust suppressants to control emissions from unpaved roads, yards, and other activities such as road grading, land clearing, and the demolition of buildings.
   [Rules 62-4.070(3) and 62-296.320(4)(c), F.A.C.]

11. Definitions: Unless otherwise specified by permit, startup, shutdown and malfunction are defined as follows.
   a. Startup: Startup is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.
   b. Shutdown: Shutdown is defined as the cessation of the operation of an emissions unit for any purpose.
   c. Malfunction: A malfunction is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.
   [Rule 62-210.200(Definitions), F.A.C.]

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

13. **Excess Emissions Allowed:** Unless otherwise specified in an emissions unit subsection or Appendices of this permit, excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing:
   
a. Best operational practices to minimize emissions are adhered to, and

b. The duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period.


14. **Excess Emissions Notification:** In case of excess emissions resulting from malfunctions, the permittee shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. (Plant Operation - Problems). If requested, a full written report on the malfunctions shall be submitted in a quarterly report. [Rule 62-210.700(6), F.A.C.]

15. **Plant Operation - Problems:** If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately (within one working day) notify the Compliance Authority. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. [Rule 62-4.130, F.A.C.]

**ADMINISTRATIVE REQUIREMENTS**

16. **Annual Statement of Compliance:** The permittee shall submit an annual statement of compliance to the compliance authority at the address shown on the cover of this permit within 60 days after the end of each calendar year during which the Title V permit was effective. [Rules 62-213.440(3)(a)2 & 3 and (b), F.A.C.]

17. **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 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]

18. **Reporting to EPA:** Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency should be sent to: EPA Region 4 Office; Air, Pesticides & Toxics Management Division; Air and EPCRA Enforcement Branch - Air Enforcement Section; 61 Forsyth Street; Atlanta, Georgia 30303-8960. The telephone number is (404)562-9155 and the fax number is (404)562-9163.

19. **Prevention of Accidental Releases (Section 112(r) of CAA):** If and when the facility becomes subject to 112(r), the permittee shall:
   
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to: RMP Reporting Center, Post Office Box 10162, Fairfax, VA 22038. The telephone number is (703)227-7650.

b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C. [40 CFR 68]
This subsection addresses the following emissions units.

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description (ARMS ID No. 0990332)</th>
</tr>
</thead>
<tbody>
<tr>
<td>001</td>
<td>Cogeneration Boilers A (EU-001), B (EU-002) and C (EU-003): Each cogeneration boiler is a 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. 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 (400 MMBtu per hour) and distillate oil (490 MMBtu per hour). 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 CO, SAM, SO₂, and VOC. Exhaust gases exit a stack that is 10 feet in diameter and at least 199 feet tall with a volumetric flow rate of approximately 319,000 acfm at 352°F.</td>
</tr>
<tr>
<td>002</td>
<td></td>
</tr>
<tr>
<td>003</td>
<td></td>
</tr>
</tbody>
</table>

The following describes the primary applicable requirements for the cogeneration boilers.

**Prevention of Significant Deterioration (PSD) of Air Quality, Rule 212.400, F.A.C.**: Permit No. PSD-FL-196 (as modified) for which the cogeneration boilers were subject to BACT determinations CO, Fl, NOₓ, Pb, PM/PM₁₀, SAM, SO₂, and VOC.

**Acid Rain**: The cogeneration plant is currently classified as a “Qualifying Cogeneration Facility” under 40 CFR Part 72 and is exempt from Acid Rain permitting. However, to maintain the exemption as a qualifying cogeneration facility, total electrical generation may not exceed 219,000 megawatt-electrical-hours (MWe-h) per unit per year based on a 3-year average. It is possible that the cogeneration boilers will later become subject to the Title IV Acid Rain provisions.


- NSPS Provisions in 40 CFR 60, incorporated by reference in Rule 62-204.800, F.A.C., including: Subpart A (General Provisions); Subpart Da (Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978); and Subpart Db (Industrial-Commercial-Institutional Steam Generating Units), and NSPS Subpart Ea (Applicability for Standards of Performance for Municipal Waste Combustors for which Construction is Commenced after December 20, 1989 and on or Before September 20, 1994).


**Compliance Assurance Monitoring (CAM)**: Rule 62-213.440(1)(b), F.A.C. applies to the particulate matter standards for the cogeneration boilers.

**EQUIPMENT SPECIFICATIONS**

1. **Production Capacity**: The cogeneration plant includes a nominal 75 MW steam turbine electrical generator and a nominal 65 MW steam turbine electrical generator. [Permitting Note: The cogeneration plant has a nominal generating capacity of 140 MW. Therefore, the facility is subject to the power plant site certification requirements of the Department. Subsequent modifications must be made in accordance with appropriate site certification requirements.] [Permit No. PSD-FL-196P; Rule 62-4.070(3), F.A.C.]

2. **Boiler Design**: The cogeneration boilers are 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 an air construction permit before firing any other fuel (including coal) not specifically authorized by this permit.

[Permit No. PSD-FL-196P; Rule 62-4.070(3), F.A.C.]

3. **Stack:** Each cogeneration boiler shall have an individual stack that is at least 199 feet tall. The permanent stack sampling facilities for each stack shall comply with Rule 62-297.310, F.A.C. [Permit No. PSD-FL-196P; Rules 62-4.070(3) and 62-297.310, F.A.C.]

4. **Process Monitors:** Each cogeneration boiler shall be equipped with instruments to measure the fuel feed rate, heat input, steam production, steam pressure, and steam temperature. [Permit No. PSD-FL-196P; Rule 62-4.070(3), F.A.C.]

5. **Control Equipment:** Each cogeneration boiler shall be equipped with:
   a. Low-NOX natural gas burners rated for no more than 0.15 lb 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 400 MMBtu per hour.
   b. 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 percent of the particulate matter greater than 10 microns in size (assuming a specific gravity of 2.00).
   c. An electrostatic precipitator designed for at least 98 percent removal of particulate matter.
   d. A selective non-catalytic reduction system designed for at least 40 percent removal of NOx.
   e. An activated carbon injection system (or equivalent) for control of potential mercury emissions.
   {Permitting Note: At the issuance of this permit, the activated carbon system was inactive and the cogeneration units demonstrated compliance with the mercury standard without injecting activated carbon.}

The permittee shall abide by the O&M plans for the cogeneration plant control equipment specified in Appendix OM of this permit. [Permit No. PSD-FL-196M; Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

6. **Good Combustion Practices:** The boiler operators shall follow the procedures for “good combustion practices” identified in Appendix GC of this permit. [Permit No. PSD-FL-196P]

7. **Continuous Monitors:** For each cogeneration boiler, the permittee shall install, calibrate, maintain, and operate a COMS to continuously measure and record opacity and CEMS to continuously measure and record emissions of CO, NOX, CO2, and 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. [Permit No. PSD-FL-196P; NSPS Subpart Da; Rules62-4.070(3) and 62-212.400 (BACT), F.A.C.]

8. **Control Equipment O&M Plan:** The permittee shall abide by the operation and maintenance (O&M) plans for the cogeneration plant control equipment specified in Appendix OM of this permit. [Permit No. PSD-FL-196P; Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

**CAPACITY, FUELS AND PERFORMANCE RESTRICTIONS**

9. **Permitted Capacity:** The maximum heat input rate to each cogeneration boiler shall not exceed 760 MMBtu/hr when burning 100 percent biomass, 400 MMBtu/hr when burning 100 percent natural gas, and 490 MMBtu/hr when burning 100 percent distillate oil. The steam production rate 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). [Permit No. PSD-FL-196P; Rules 62-4.070(3), Rule 62-210.200 (PTE), and 62-212.400 (BACT), F.A.C.]

10. 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 percent by weight yard waste (yard trash) on a calendar quarter basis that is defined as a municipal solid waste 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 abide by the Ash and Fuel Management Plans specified in Appendices AM and FM of this permit. [Permit No. PSD-FL-196P; Rules 62-4.070(3), Rule 62-210.200 (PTE), and 62-212.400 (BACT), F.A.C.]

11. Auxiliary Fuel: The cogeneration boilers shall fire only distillate oil and natural gas as auxiliary fuels. The maximum sulfur content of distillate oil is limited to 0.05 percent by weight. In addition to the primary authorized fuels, each boiler may startup on natural gas or distillate oil. The firing of all 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. The permittee shall abide by the Ash and Fuel Management Plans specified in Appendices AM and FM of this permit. [Permit No. PSD-FL-196P; Rules 62-4.070(3), Rule 62-210.200 (PTE), and 62-212.400 (BACT), F.A.C.]


EMISSION LIMITING STANDARDS

13. Emissions Standards: Unless otherwise specified, the averaging period for an emissions standard is based on the averaging period specified in the applicable test method. Based on the maximum permitted heat input to each cogeneration boiler, stack emissions shall not exceed the standards specified in the following table:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Emissions Standards per Boiler</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>lb/MMBtu</td>
</tr>
<tr>
<td>Carbon Monoxide</td>
<td>30-day rolling CEMS avg.</td>
<td>0.50</td>
</tr>
<tr>
<td></td>
<td>12-month rolling CEMS avg.</td>
<td>0.35</td>
</tr>
<tr>
<td>Nitrogen Oxides</td>
<td>30-day rolling CEMS avg.</td>
<td>0.15</td>
</tr>
<tr>
<td>Sulfur Dioxide</td>
<td>24-hour rolling CEMS avg.</td>
<td>0.20</td>
</tr>
<tr>
<td></td>
<td>30-day rolling CEMS avg.</td>
<td>0.10</td>
</tr>
<tr>
<td></td>
<td>12-month rolling CEMS avg.</td>
<td>0.06</td>
</tr>
<tr>
<td>Stack Opacity</td>
<td>6-minute block average by COMS and EPA Method 9</td>
<td>≤ 20% opacity, except for one 6-minute block per hour ≤ 27% opacity</td>
</tr>
<tr>
<td>Particulate Matter</td>
<td>3-run test avg.</td>
<td>0.026</td>
</tr>
</tbody>
</table>
### SECTION 3. EMISSIONS UNIT SPECIFIC CONDITIONS

#### A. Cogeneration Boilers

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Emissions Standards per Boiler¹</th>
<th>lb/MMBtu</th>
<th>lb/hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volatile Organic Compounds</td>
<td>3-run test avg.</td>
<td>0.05</td>
<td>38.0</td>
<td></td>
</tr>
<tr>
<td>Mercury</td>
<td>3-run test avg.</td>
<td>5.4 x 10⁻⁶</td>
<td>NA</td>
<td></td>
</tr>
<tr>
<td>Lead and Fluorides</td>
<td></td>
<td>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.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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. Each cogeneration boiler is also subject to Rule 62-296.405(2)(d), F.A.C. and 40 CFR 60.44a, which limits NOₓ emissions to 0.20 lb/MMBtu for gaseous fuels, 0.30 lb/MMBtu for liquid fuels, and 0.60 lb/MMBtu for solid fuels. Compliance with the BACT standard ensures compliance with these standards.

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. Each cogeneration boiler is also subject to Rule 62-296.405(2)(c), F.A.C. and 40 CFR 60.43a(d)(2), which limits SO₂ emissions to 1.20 lb/MMBtu for solid fuels and 0.20 lb/MMBtu for liquid or gaseous fuels. Compliance with the BACT standard ensures compliance with these standards. [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 percent 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. Each cogeneration boiler is also subject to Rule 62-296.405(2)(a), F.A.C. and 40 CFR 60.42a, which limits visible emissions to no more than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Compliance with the BACT standard ensures compliance with these standards.

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. Each cogeneration boiler is also subject to Rule 62-296.405(2)(b), F.A.C. and 40 CFR 60.42a, which limits particulate matter emissions to 0.03 lb/MMBtu.
Compliance with the BACT standard ensures compliance with these standards.

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, 29 or 30B. 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 Authority a mercury testing protocol designed to establish an effective carbon injection rate to control mercury emissions. Within 60 days of receiving approval for the mercury testing protocol by the permitting authority, the permittee shall begin the approved testing program. At a minimum, the permittee shall submit a full engineering report summarizing the uncontrolled emissions, controlled emissions, fuels, operating capacities, and recommending a minimum activated carbon injection rate to control mercury emissions.

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

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 and Appendix CT.

[Permit No. PSD-FL-196P; Rules 62-4.070(3), Rule 62-210.200 (PTE), and 62-212.400 (BACT), F.A.C.]

14. Rule 62-296.405(2), F.A.C.: The cogeneration boilers are considered “Fossil Fuel Steam Generators with More Than 250 Million Btu per Hour Heat Input” and are subject to the following requirements for new units.

   a. Visible Emissions – (See subsection 62-204.800(7), F.A.C., and 40 C.F.R. 60.42 and 60.42a).
   b. Particulate Matter – (See subsection 62-204.800(7), F.A.C., and 40 C.F.R. 60.42 and 60.42a).
   c. Sulfur Dioxide – (See subsection 62-204.800(7), F.A.C., and 40 C.F.R. 60.43 and 60.43a).
   d. Nitrogen Oxides – (See subsection 62-204.800(7), F.A.C., and 40 C.F.R. 60.44 and 60.44a).

   The units were constructed in accordance with NSPS Subpart Da for Electric Utility Steam Generating Units. These provisions are included in Appendix 60Da of Section 4 of this permit.

15. Rule 62-296.410, F.A.C.: The cogeneration boilers are considered “Carbonaceous Fuel Burning Equipment” and are subject to the following requirements for new units with a maximum heat input rate equal to or greater than 30 MMBtu per hour.

   a. Visible Emissions – 30 percent opacity except that a density of 40 percent opacity is permissible for not more than two minutes in any one hour.
   b. Particulate Matter – 0.2 lb/MMBtu of heat input of carbonaceous fuel plus 0.1 lb/MMBtu of heat input of fossil fuel.

16. Rule 62-296.570, F.A.C.: The cogeneration boilers operate in Palm Beach County and are subject to the Reasonably Available Control Technology (RACT) Requirements for Major VOC- and NOx-Emitting
Facilities. Emissions of VOC and NO\(_X\) from carbonaceous fuel burning facilities, other than waste-to-energy facilities, shall not exceed 5.0 lb/MMBtu and 0.9 lb/MMBtu, respectively.

**STARTUP, SHUTDOWN, AND MALFUNCTION**

17. **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.

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.

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). The ESP shall be placed on line at the earliest possible time during the startup period, consistent with the manufacturer’s recommendations, operating experience and safety practices. Once the ESP is placed on line, the boiler shall comply with the specified opacity standard. 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 NO\(_X\) 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 NO\(_X\)) shall be excluded in a 24-hour period due to a cold startup. No more than three hourly emission rate values (CO or NO\(_X\)) shall be excluded in a 24-hour period due to a warm startup. No more than two hourly emission rate values (CO or NO\(_X\)) shall be excluded in a 24-hour period due to a malfunction. No more than two hourly emission rate...
values (CO or NO\textsubscript{X}) 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\textsubscript{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 NO\textsubscript{X} 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 (Excess Emissions), F.A.C. cannot vary any NSPS requirement or NESHAP provision.


18. Startup/Shutdown Plan: The following procedures will be used to minimize the magnitude and duration of emissions during startup and shutdown.

a. Startup Procedures.
   1) The ESP air flushing system and heater are placed in service at least eight hours prior to boiler light off.
   2) The boiler is started up on natural gas or distillate oil prior to energizing the ESP.
   3) The ESP shall be placed on line at the earliest possible time during the startup period, consistent with the manufacturer’s recommendations, operating experience and safety practices. Once the ESP is placed on line, the boiler shall comply with the specified opacity standard. The ESP shall be on line and functioning properly before firing any biomass.
   4) Manual controls are used to ensure optimum air-to-fuel ratios during the startup period.
   5) The startup fuel is reduced gradually while the biomass firing rate is increased.

b. Shutdown Procedures.
   1) Manual controls are employed to ensure optimum air-to-fuel ratios during the shutdown period.
   2) For shutdown, the ESP is not deactivated until the fuel feed to the furnace is stopped.

[Application No. 0990005-017-AV]

TESTING

19. Stack Testing 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.

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 CT 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 percent 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 percent 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:** As necessary, compliance with the emission limits specified in this permit shall be demonstrated using the following EPA Methods (or most recent versions), as contained in 40 CFR Parts 60 and 61.

<table>
<thead>
<tr>
<th>EPA Method</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Selection of sample site and velocity traverses</td>
</tr>
<tr>
<td>2</td>
<td>Stack gas flow rate when converting concentrations to or from mass emission limits</td>
</tr>
<tr>
<td>3A</td>
<td>Gas analysis when needed for calculation of molecular weight or percent O&lt;sub&gt;2&lt;/sub&gt;</td>
</tr>
<tr>
<td>4</td>
<td>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</td>
</tr>
<tr>
<td>5</td>
<td>Particulate matter emissions</td>
</tr>
<tr>
<td>6 or 6C</td>
<td>Sulfur dioxide emissions</td>
</tr>
<tr>
<td>7 or 7E</td>
<td>Nitrogen oxide emissions</td>
</tr>
</tbody>
</table>
| 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 |
| 30B        | Determination of Total Vapor Phase Mercury |
SECTION 3. EMISSIONS UNIT SPECIFIC CONDITIONS

A. Cogeneration Boilers

<table>
<thead>
<tr>
<th>EPA Method</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>101A</td>
<td>Particulate and gaseous mercury emissions</td>
</tr>
</tbody>
</table>

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 CT of this permit. The permittee shall use CEMS and COMS data to demonstrate compliance with the emissions standards for CO, NOx, SO2, and opacity. [Permit No. PSD-FL-196P; Rules 62-204.800 and 62-297.100, F.A.C.; and 40 CFR 60, Appendix A]

MONITORING

20. CEMS and COMS: For each cogeneration boiler, the permittee shall install, calibrate, maintain, and operate a COMS to continuously measure and record opacity and CEMS to continuously measure and record emissions of CO, NOx, CO2 (for O2), and SO2 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) The NOx and SO2 CEMS shall comply with Performance Specification 2 in Appendix B of 40 CFR 60. The SO2 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.
4) The 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 Condition 17 of this subsection. 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 SO2 CEMS shall express the 1-hour emission averages in terms of “lb/MBtu of heat input”. The CO2 CEMS shall express the 1-hour emission average (CO2 and O2) 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 percent in any calendar quarter. In the event 95 percent availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95 percent availability and a plan of corrective actions that will be taken to achieve 95 percent 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 (Federal Rule Adopted by Reference) 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).

[Permit No. PSD-FL-196P; Rules 62-4.070 and 62-212.400 (BACT), F.A.C.]

21. **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 NO\textsubscript{X} emissions data recorded by the CEMS. The permittee shall identify minimum urea injection rates for various load conditions that ensure compliance with the NO\textsubscript{X} standards. Should the NO\textsubscript{X} 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. [Permit No. PSD-FL-196P; Rules 62-4.070 and 62-212.400 (BACT), F.A.C.]

22. **Power Generation:** In conjunction with the Annual Operating Report, the permittee shall report the annual power generation (MW\textsubscript{e}-hours per year) for the previous calendar year and the 3-year average for the previous three calendar years. The report shall identify whether the cogeneration plant remains a “Qualifying Cogeneration Facility” as specified in 40 CFR Part 72 and is exempt from Acid Rain permitting. [40 CFR 72; Rule 62-4.070(3), F.A.C.]
RECORD KEEPING AND REPORTING

23. **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 \( \text{SO}_2 \) emissions and the 12-month rolling total \( \text{SO}_2 \) emissions shall be determined and kept in a log. In addition, the permittee shall abide by the Ash and Fuel Management Plans specified in Appendices AM and FM. [Permit No. PSD-FL-196P; Rules 62-4.070 and 62-212.400 (BACT), F.A.C.]

24. **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 the “Quarterly Report” included in Appendix QR of this permit. In addition to the information identified in this report, 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 authorized representative shall certify that the information provided in each quarterly report is true, accurate, and complete to the best of his/her knowledge. The quarterly reports and summaries shall be submitted to the Compliance Authority no later than 30 days following each calendar quarter. [Permit No. PSD-FL-196P; Rules 62-4.070 and 62-212.400 (BACT), F.A.C.]

OTHER APPLICABLE REQUIREMENTS

25. **NSPS Provisions**: In accordance with Rule 62-204.800(8), F.A.C., the cogeneration boilers are subject to the applicable requirements of 40 CFR 60, including: Subpart A (General Provisions), Subpart Da (Standards of Performance for Electric Utility Steam Generating Units), Subpart DDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, and NSPS Subpart Ea (Applicability for Standards of Performance for Municipal Waste Combustors for which Construction is Commenced after December 20, 1989 and on or Before September 20, 1994), and Subpart Ea (Applicability for Municipal Waste Combustors). The applicable provisions are specified in Appendices 60A, 60Da, 60DDDD, and 60Ea in Section 4 of this permit.

26. **CAM Plan**: Pursuant to Rule 62-213.440(1)(b)1.a., F.A.C. and 40 CFR 64, the cogeneration boilers shall comply with the CAM plan specified in Appendix CM in Section 4 of this permit.
SECTION 3. EMISSIONS UNIT SPECIFIC CONDITIONS

B. Material Handling and Storage Operations - Cogeneration Plant

This subsection addresses the following emissions units.

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>004</td>
<td>Cogeneration Plant - Material Handling and Storage includes unloading operations, stockpiles, transfer operations, conveyors, screens, crushers, hoppers and silos.</td>
</tr>
</tbody>
</table>

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 bagasse, authorized wood, fly ash, bottom ash, and a mercury removal agent (e.g., activated carbon). Unconfined particulate matter emissions from the operations shall be controlled by the use of the BACT controls and reasonable precautions specified in the following conditions.

EQUIPMENT SPECIFICATIONS

1. Equipment: The authorized methods of operation include the following:

   a. **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 and #2); unloading conveyor; disk screen; hogger; storage conveyor; radial stacker; biomass storage pile (active and inactive); 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 and #2); boiler meter bins; recycle conveyor; and the fixed recycle stacker.

   b. **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 load-out; mechanical dust collector hoppers; mixed (bottom and fly) ash conveyor belt; and mixed ash bunker. *(Permitting Note: The fly ash silo, fly ash pug mill conditioners and fly ash truck load-out have not operated for several years and the plant currently sends fly ash to the mixed ash conveyor belt and then to the mixed ash bunker.)*

   c. **Activated Carbon Handling and Storage Operations**: The permittee is authorized to handle and store activated carbon. The following activities are associated with these operations: pneumatic truck unloading system; three storage silos; and injection system.

   d. **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 and enclosed drag chain conveyors; transfer conveyor; collection conveyor; three-walled storage bunker; and bottom ash truck load-out.


2. **Baghouses**: The fly ash storage silo shall be controlled by a baghouse and the three activated carbon silos shall be controlled by a single, common baghouse. Each baghouse shall be designed, operated and maintained to achieve an outlet dust loading of no greater than 0.01 grains per actual cubic feet of exhaust. New and replacement bags shall meet this equipment specification based on vendor design information. No particulate matter emissions tests are required. When the mercury control system is operating, the activated carbon storage silos shall be maintained at a negative pressure with the exhaust vented through the baghouse. *(Permitting Note: The fly ash silo and fly ash silo baghouse have not been operated for several years and the plant currently sends fly ash to the mixed ash conveyor belt and then to the mixed ash bunker. In addition, the activate carbon silos have not been used for several years since the mercury limit can be met without the injection of activated carbon.)* [Permit No. PSD-FL-196P; Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]
3. **Ash and Fuel Management Plans:** The permittee shall abide by the Ash and Fuel Management Plans specified in Appendix AM and FM, respectively. [ Permit No. PSD-FL-196P]

4. **Control Equipment O&M Plan:** The permittee shall abide by the operation and maintenance (O&M) plans for the cogeneration plant control equipment specified in Appendix OM of this permit. [ Permit No. PSD-FL-196P; Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

**PERFORMANCE RESTRICTIONS**

5. **Hours of Operation:** The permittee is authorized to operate the materials handling and storage operations continuously (8760 hours per year). [ Rule 62-210.200 (PTE), F.A.C.]

**EMISSION LIMITING STANDARDS**

6. **Baghouse Vents:** As determined by EPA Method 9, visible emissions from each baghouse vent shall not exceed 5 percent opacity. [ Permit No. PSD-FL-196P; Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

7. **Fugitive Dust from Material Handling:** The following conditions apply to the biomass and ash handling facilities.
   a. Except for those associated with the stacker/reclaimer, all conveyors and conveyor transfer points shall be enclosed to prevent fugitive particulate matter emissions.
   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 shall not exceed 20 percent opacity.
   c. The fly ash handling system including all transfer points and the storage bin shall be enclosed. Bottom ash and fly ash shall be wetted and transferred in enclosed conveyors to the enclosed ash storage building. Alternatively, the ash shall be wetted and discharged to the ash storage silo.
   d. The distance that biomass fuel is dropped during handling shall be minimized.
   e. Windbreaks around the material handling equipment shall be used as necessary.
   f. Maintenance of paved areas as needed.

   [ Permit No. PSD-FL-196P; Rules 62-4.070(3), 62-296.320(4)(c), and 62-212.400 (BACT), F.A.C.]

**TEST REQUIREMENTS**

8. **Baghouse Vents:** At least once during each federal fiscal year (October 1 through September 30), the permittee shall test each silo baghouse vent in accordance with EPA Method 9. Due to infrequent use, the baghouse vent for the fly ash storage silo shall be tested during any federal fiscal year in which the fly ash storage silo operates more than 400 hours, and the baghouse vent for the activated carbon silos shall be tested during any federal fiscal year in which the activated carbon injection system operates more than 400 hours. The baghouse vent for the activated carbon silos shall be tested during a delivery of activated carbon. Tests shall be conducted in accordance with the applicable requirements in Appendix CT of this permit. The minimum observation period for an opacity test shall be 30 minutes. [ Permit No. PSD-FL-196P; Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

9. **Test Reports:** For each visible emissions test conducted, the permittee shall file a test report with the Department as soon as practical, but no later than 45 days after the last sampling run of each test is completed. Each test report shall include the information specified in Rule 62-297.310(8), F.A.C. as summarized in Appendix CT of this permit. [ Rules 62-297.310(8), F.A.C.]
This subsection addresses the following emissions units.

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>021</td>
<td>Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1</td>
</tr>
<tr>
<td>022</td>
<td>Central Dust Collection System No. 2 with Rotoclone No. 2 – “B” System</td>
</tr>
<tr>
<td>023</td>
<td>Cooler No. 1 with Rotoclone No. 3</td>
</tr>
<tr>
<td>024</td>
<td>Cooler No. 2 with Rotoclone No. 4</td>
</tr>
<tr>
<td>025</td>
<td>Fluidized Bed Dryer/Cooler with Baghouse</td>
</tr>
<tr>
<td>034</td>
<td>Bulk Load-Out Operation</td>
</tr>
<tr>
<td>035</td>
<td>Transfer Bulk Load-out Station</td>
</tr>
<tr>
<td>043</td>
<td>Sugar Refinery Alcohol Usage</td>
</tr>
<tr>
<td>054</td>
<td>Wet Rotoclone No. 6 – “A” System (Permit No. 0990005-027-AC)</td>
</tr>
<tr>
<td>055</td>
<td>Wet Rotoclone No. 7 - “C” System (Permit No. 0990005-027-AC)</td>
</tr>
</tbody>
</table>

{Permitting Note: The sugar refinery was last modified by Permit No. 0990005-030-AC.} (0990005-031-AC was a short term exemption for a temporary jaw crusher used in demolition of the carpenter shop and three adjacent concrete slabs).

**Miscellaneous Process Descriptions**

The sugar refinery consists of several miscellaneous emissions units that handle, process, store, and transfer a variety of sugar products. These units and activities can generate emissions of particulate matter, mostly sugar. In 2008, Permit No. 0990005-021-AC authorized the expansion of the mill boiling house by installing new process equipment to produce specialty sugars products. The permit authorized: 1) an increase in the capacity of total refined sugar production; 2) an increase in the capacity of refined sugar production from the Fluidized Bed Dryer/Cooler baghouse system, the Bulk Load-out Station, and the Transfer Bulk Load-out Station; 3) a modification of Central Dust Collection System Nos. 1 and 2; an overall reduction in particulate matter emissions; and 5) alternative methods of operation for the Fluidized Bed Dryer/Cooler and the Rotary Dryer/Cooler systems.

The primary sugar drying system is a Fluidized Bed Dryer/Cooler (EU-025) with a design equipment capacity of approximately 1350 tons per day. Steam is used for the necessary heat and no fuels are fired in the dryer. The exhaust is controlled by a high efficiency baghouse manufactured by BETH GmbH, 23556 LÜbeck (Type BETHPULS 6.60 x 7.5.10). The baghouse exhausts through a stack 93 feet above grade.

A Rotary Dryer (EU-021) is used for specialty sugars and when the fluidized bed dryer is off line for repairs. Steam is used for the necessary heat and no fuels are fired in the dryer. Dust emissions from the rotary dryer are controlled with the use of a skimmer followed by wet Rotoclone No. 1, (uses 2 gpm water injection), which exhausts 89 feet above grade. Sugar from the rotary dryer is directed to two coolers (EU-023 and EU-024), each with a design capacity of 1350 tons per day. The exhaust from Cooler No. 1 is controlled by Rotoclone No. 3 vented 80 feet above grade. The exhaust from Cooler No. 2 is controlled by Rotoclone No. 4 vented 80 feet above grade. The 3-stage high-production mode (rotary dryer followed by two coolers operating in series) is needed when producing approximately 1000 tons per day of refined white sugar and 600 tons per day of specialty sugars. When operating the rotary system in the low-production mode (< 1000 tons white sugar per day or < 600 tons specialty sugar per day), Cooler No. 1 (EU-023) functions as the dryer followed in series by Cooler No. 2 (EU-024) and the rotary dryer remains shutdown. The Rotary System may operate simultaneously with the Fluidized Bed Dryer/Cooler.
SECTION 3. EMISSIONS UNIT SPECIFIC CONDITIONS

D. Sugar Refinery

Dust collection System “A”, _Roto-clone No. 6_ (EU-054) controls fourteen (14) drop points at the fluidized Bed System and fourteen (14) drop points at the Rotary Dryer System. The drop points include the following:
- Belt Conveyors 11(B) and GG(x2)
- Screw Conveyors Q1, 25, 25A, 28, 19, 46, Q2 and S1
- Bulk Curing Bins 1, 2, 3, or 7
- Bucket Elevators 10, 16, B, GG#5
- Sweco Shaker Screen
- Rotex Screen 9346 (to GG#8)

Dust Collection, System “B”, _Roto-clone No. 2_ (EU-022) which exhausts 86 feet above grade, is used to control dust emissions from several miscellaneous sources. Total drop points controlled are twenty (20) at the Fluidized Bed System, and four (4) at the Rotary Dryer System. The drop points include the following:
- Belt Conveyor 19, 11(T), GG8(x2)
- Screw Conveyors 12(x3), 14, 20, 40, 45 and S2
- Packing Room Bins (5 pound and 100 pound)
- Bulk Curing Bins 4, 5, or 6
- Bucket Elevators 43 and 15
- Production Scale, Silo Scale, HN-1, Rotex

Dust Collection, System “C”, _Roto-clone No. 7_ (EU-055), controls twelve (12) drop points in the Fluidized Bed System, and one (1) drop point in the Rotary Dryer System. The drop points include the following:
- Belt Conveyors A(x2) and B(x2)
- Screw conveyors 20A, 26, 27, 29, 30, 42, and N
- Reject Chute

The Bulk Load-Out Operation (EU-034) with a design equipment capacity of 600 tons per day is 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.

The Transfer Bulk Load-Out Station (EU-035) with a design equipment capacity of 1200 tons per day is used to supply sugar to the Transshipment Facility. The operation includes four enclosed conveyors in series feeding refined sugar from the storage silo or bulk curing bins to an enclosed load-out building. Emissions of fugitive particulate matter are controlled by use of the enclosure and high-pressure air curtains.

The expansion project extended by 40 feet the south end of the sugar refinery building (now 40 feet by 120 feet), which houses the following associated process equipment: The following equipment will be housed in the expansion: two melters, two syrup tanks, two grain receiver tanks, two vacuum pans, two magma/cut tanks, two batch centrifuges, two molasses tanks, two screw conveyors, one magma mingler, one run-off tank, a motor control center room, and various pumps and piping systems. The other portion of the existing sugar refinery building houses the following associated process equipment: a 1700-cubic feet vacuum pan, a vacuum pan condenser, two centrifugals, syrup and molasses feed tanks, final liquor syrup storage tanks, one 5000 gallon condensate collection tank, one 1000 gallon centrifugal wash water tank, two 1200 cubic feet seeder cutover tanks, a motor control center room, the motor control center and centrifugal controller room, a refined sugar conveying system, one 2000 cubic feet receiver and various pumps.

Two types of alcohol, isopropyl alcohol and organic ethanol, are used in the sugar refinery to aid in the crystallization process in the vacuum pans (EU-043). Isopropyl alcohol is used in the production of standard refined sugar and is the primary source of VOC emissions. Organic ethanol is used in the production of organic sugar.

For the sugar refinery, dust-generating activities that are completely enclosed and vented within the building are not classified as air pollution sources.
EQUIPMENT SPECIFICATIONS

1. **Baghouse Specifications**: To control emissions from the fluidized bed dryer (EU-025), the permittee shall operate and maintain a baghouse control system with the following specifications:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Specification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Design exhaust flow rate</td>
<td>70,620 acfm</td>
</tr>
<tr>
<td>Filtering area</td>
<td>9041 ft²</td>
</tr>
<tr>
<td>Air-to-cloth ratio</td>
<td>7.81 cfm/ft²</td>
</tr>
<tr>
<td>Control efficiency</td>
<td>99.8% (PM and PM₁₀)</td>
</tr>
</tbody>
</table>

[Rule 62-4.070(3), F.A.C. and Permit No. 0990005-021-AC]

2. **Cyclonic Control Devices**: The permittee shall operate and maintain the following emission units and corresponding control equipment in accordance with the specifications identified in the table below:

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Description</th>
<th>Control Type</th>
<th>Design Flow Rates acfm</th>
<th>Water Injection Rate (gpm, min.)</th>
<th>Control Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>021</td>
<td>Rotary Dryer, Central Dust Collection System No. 1</td>
<td>Roto-clone No. 1</td>
<td>15,000</td>
<td>2</td>
<td>99.9% 99%</td>
</tr>
<tr>
<td>022</td>
<td>“B” System</td>
<td>Roto-clone No. 2</td>
<td>14,770</td>
<td>2</td>
<td>99.9% 99%</td>
</tr>
<tr>
<td>023</td>
<td>Cooler No. 1</td>
<td>Roto-clone No. 3</td>
<td>15,000</td>
<td>2</td>
<td>99.9% 99%</td>
</tr>
<tr>
<td>024</td>
<td>Cooler No. 2</td>
<td>Roto-clone No. 4</td>
<td>15,000</td>
<td>2</td>
<td>99.9% 99%</td>
</tr>
<tr>
<td>054</td>
<td>“A” System</td>
<td>Roto-clone No. 6</td>
<td>15,078</td>
<td>2</td>
<td>99.9% 99%</td>
</tr>
<tr>
<td>055</td>
<td>“C” System</td>
<td>Roto-Clone No. 7</td>
<td>12,895</td>
<td>2</td>
<td>99.9% 99%</td>
</tr>
</tbody>
</table>


CAPACITY AND PERFORMANCE RESTRICTIONS

3. **Permitted Capacities**: Total refined sugar production (Fluidized Bed Dryer (EU-025), Rotary Dryer (EU-021), Cooler No. 1 (EU-023) and Cooler No. 2 (EU-024) shall not exceed 490,000 tons during any consecutive 52-week period, and:
   a. The Rotary System (EU-021, EU-023 and EU-024) shall not process more than 130,000 tons during any consecutive 52-week period.
   b. The Bulk Load-Out Operation (EU-034) shall not process more than 139,000 tons of refined sugar during any consecutive 52-week period.
   c. The Transfer Bulk Load-Out Station (EU-035) shall not process more than 351,000 tons of refined sugar during any consecutive 52-week period.
   d. Isopropyl alcohol usage (EU-043) from the sugar refinery shall not exceed 78,040 pounds during any consecutive 52-week period.


4. **Hours of Operation**: Operation of the sugar refinery is limited by the limitations on processing capacities. The hours of operation are not limited (8,760 hours per year). [Permit No. 0990005-021-AC and 027-AC]
METHODS OF OPERATION

5. **Method of Operation**: The owner or operator is authorized to operate the dryers in any of the following methods.

a. The Fluidized Bed Dryer (EU-025) only;

b. Rotary System only:
   
   1) 3-Stage High-Production Mode: The Rotary Dryer (EU-021) is operated with Cooler No. 1 (EU-023) and Cooler No. 2 (EU-024) in series. In this mode, high production rates are approximately 1000 tons per day for white refined sugar and above 600 tons per day for specialty sugars.

   2) 2-Stage Low-Production Mode: The Rotary Dryer (with Rotoclone No. 1, EU-021) is off and Cooler No. 1 (with Rotoclone No. 3, EU-023) is operated as a dryer followed by Cooler No. 2 (with Rotoclone No. 4, EU-024) in series. In this mode, low production rates are below 500 tons per day for specialty sugars.

c. The Fluidized Bed Dryer (EU-025) and Rotary System (EU-021, EU-023 and EU-024) may be operated simultaneously. The dryers and sugar refinery are subject to the production and processing limitations specified in Specific Condition No. 3 of this subsection. [Permit No. 0990005-021-AC and -027-AC.]
EMISSION LIMITING STANDARDS

6. Opacity Standards:
   a. Visible emissions shall not exceed 5 percent opacity from the following exhaust points: Rotary Dryer, Central Dust Collection System No. 1 with Roto-clone No. 1 (EU-021); Central Dust Collection System No. 2 with “B” System Roto-clone No. 2 (EU-022); Cooler No. 1 with Roto-clone No. 3 (EU-023); Cooler No. 2 with Roto-clone No. 4 (EU-024); Also “A” System “Roto-clone No. 6 (EU-054), “C” System Roto-clone No. 7, (EU-055) and Fluidized Bed, Dryer/Cooler Baghouse (EU-025).
   
b. Visible emissions shall not exceed 20 percent opacity from the following areas: the Bulk Load-Out Operation (EU-034), the Transfer Bulk Load-out Station (EU-035) and fugitive emissions at the sugar refinery.

   [Rules 62-296.320(4) and 62-297.620(4), F.A.C.; and Permit No. 0990005-021-AC]

7. PM/PM_{10} Emissions: The sum of emissions shall not exceed 22.15 tons of PM per year and 3.00 tons of PM_{10} per year from the following emission units: the Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1 (EU-021); the Central Dust Collection System No. 2 (“B” System) with Rotocloud No. 2 (EU-022); the Cooler 1 with Rotocloud No. 3 (EU-023); the Cooler 2 with Rotocloud No. 4 (EU-024); the Fluidized Bed Dryer/Cooler with Baghouse (EU-025); “A” System Roto-clone No. 6 (EU-054); “C” System Roto-clone No. 7 (EU-055); the Bulk Load-Out Operation (EU-034); and the Transfer Bulk Load-out Station (EU-035). [Rule 62-210.200(PTE), F.A.C. and Permit No. 0990005-021-AC and 0990005-027-AC]

8. Potential PM/PM_{10} Emissions: For informational purposes only, the following table summarizes the potential emissions from the sugar refinery emissions units:

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Description</th>
<th>Tons/Year</th>
<th>PM</th>
<th>PM_{10}</th>
</tr>
</thead>
<tbody>
<tr>
<td>021</td>
<td>Rotary Dryer, Central Dust Collection System No. 1 with Roto-clone No. 1</td>
<td>4.09</td>
<td>1.645</td>
<td></td>
</tr>
<tr>
<td>022</td>
<td>Central Dust Collection System No. 2 with Roto-clone No. 2 (“B” System)</td>
<td>0.44</td>
<td>0.174</td>
<td></td>
</tr>
<tr>
<td>023</td>
<td>Cooler No. 1 with Roto-clone No. 3</td>
<td>4.09</td>
<td>1.64</td>
<td></td>
</tr>
<tr>
<td>024</td>
<td>Cooler No. 2 with Roto-clone No. 4</td>
<td>0.45</td>
<td>0.18</td>
<td></td>
</tr>
<tr>
<td>025</td>
<td>Fluidized Bed Dryer/Cooler with Baghouse</td>
<td>14.70</td>
<td>0.588</td>
<td></td>
</tr>
<tr>
<td>034</td>
<td>Bulk Load-Out Operation</td>
<td>3.63</td>
<td>0.15</td>
<td></td>
</tr>
<tr>
<td>035</td>
<td>Transfer Bulk Load-out Station</td>
<td>1.83</td>
<td>0.07</td>
<td></td>
</tr>
<tr>
<td>054</td>
<td>Roto-clone No. 6 (“A”System)</td>
<td>0.51</td>
<td>0.205</td>
<td></td>
</tr>
<tr>
<td>055</td>
<td>Roto-clone No. 7 (“C” System)</td>
<td>0.38</td>
<td>0.154</td>
<td></td>
</tr>
</tbody>
</table>

   [Permit No. 0990005-021-AC]

9. PM/PM_{10} Emission Factors: The permittee shall use the following emission factors to calculate PM/PM_{10} emissions (including calculations for the Annual Operating Report).
### SECTION 3. EMISSIONS UNIT SPECIFIC CONDITIONS

#### D. Sugar Refinery

<table>
<thead>
<tr>
<th>Permit No.</th>
<th>Description</th>
<th>PM Uncontrolled</th>
<th>Control Efficiency</th>
<th>PM10 Uncontrolled</th>
<th>Control Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>021</td>
<td>Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1</td>
<td>3.150% (from dryer)</td>
<td>99.9%</td>
<td>0.125% (from dryer)</td>
<td>99.0%</td>
</tr>
<tr>
<td>022</td>
<td>Central Dust Collection System No. 2 with Rotoclone No. 2 (“B” System)</td>
<td>1.777 lb/ton</td>
<td>99.9%</td>
<td>0.071 lb/ton</td>
<td>99.0%</td>
</tr>
<tr>
<td>023</td>
<td>Cooler No. 1 with Rotoclone No. 3</td>
<td>0.175%</td>
<td>99.9%</td>
<td>0.007%</td>
<td>99.0%</td>
</tr>
<tr>
<td>024</td>
<td>Cooler No. 2 with Rotoclone No.4</td>
<td>0.175%</td>
<td>99.9%</td>
<td>0.007%</td>
<td>99.0%</td>
</tr>
<tr>
<td>025</td>
<td>Fluidized Bed Dryer/Cooler with Baghouse</td>
<td>1.5%</td>
<td>99.8%</td>
<td>0.060%</td>
<td>99.8%</td>
</tr>
<tr>
<td>034</td>
<td>Bulk Load-Out Operation</td>
<td>0.105 lb/ton</td>
<td>50%</td>
<td>0.00418 lb/ton</td>
<td>50%</td>
</tr>
<tr>
<td>035</td>
<td>Transfer Bulk Load-out Station</td>
<td>0.105 lb/ton</td>
<td>90%</td>
<td>0.00418 lb/ton</td>
<td>90%</td>
</tr>
<tr>
<td>054</td>
<td>Roto-clone No. 6 (“A” System)</td>
<td>1.045 lb/ton</td>
<td>99.9%</td>
<td>0.042 lb/ton</td>
<td>99.0%</td>
</tr>
<tr>
<td>055</td>
<td>Roto-clone No. 7 (“C” System)</td>
<td>0.105 lb/ton (Rotary Dryer) 1.463 lb/ton (Fluidizer Drying)</td>
<td>99.9%</td>
<td>0.0042 lb/ton (Rotary Dryer) 0.059 lb/ton (Fluidizer Drying)</td>
<td>99.0%</td>
</tr>
</tbody>
</table>

[Permit No. 0990005-021-AC & 0990005-027-AC]

10. Alcohol Usage: VOC emissions from alcohol usage shall not exceed 39.00 tons during any consecutive 52-week period. (*Permitting Note: VOC emissions are contributed mainly from isopropyl alcohol.*) [Permit No. 0990005-021-AC]

### TESTING REQUIREMENTS

11. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the following baghouse and Roto-clone exhaust points shall be tested to demonstrate compliance with the opacity standard specified in this subsection: Rotary Dryer, Central Dust Collection System No. 1 with Roto-clone No. 1 (EU-021); Central Dust Collection System No. 2 (“B” System) with Roto-clone No. 2 (EU-022); Cooler No. 1 with Roto-clone No. 3 (EU-023); Cooler No. 2 with Roto-clone No.4 (EU-024); Fluidized Bed Dryer/Cooler with Baghouse (EU-025); “A” System with Roto-clone No. 6 (EU-054); and “C” System with Roto-clone No. 7 (EU-055). [Rule 62-297.310(7)(a)4, F.A.C. and Permit No.0990005-021-AC and -027-AC].

12. Tests Prior to Renewal: Within the 12-month period prior to renewing the operation permit, the following baghouse and Roto-clone exhaust points shall be tested to demonstrate compliance with the opacity standard specified in this subsection: Rotary Dryer, Central Dust Collection System No. 1 with Roto-clone No. 1 (EU-021); Central Dust Collection System No. 2 with “B” System Roto-clone No. 2 (EU-022); Cooler No. 1 with Roto-clone No. 3 (EU-023); Cooler No. 2 with Rotoclone No.4 (EU-024); and Fluidized Bed Dryer/Cooler with Baghouse (EU-025). “A” System Roto-clone No. 6 (EU-054) and “C” System Roto-clone No. 7 (EU-055). [Rule 62-297.310(7) (a)3, F.A.C.]

14. **PM Testing:** The PM compliance test requirements are waived in lieu of the alternative opacity standard of 5 percent for: Rotary Dryer, Central Dust Collection System No. 1 with Roto-clone No. 1 (EU-021); Central Dust Collection System No. 2 with Roto-clone No. 2 (EU-022) “B” System; Cooler No. 1 with Rotoclon No. 3 (EU-023); Cooler No. 2 with Roto-clone No.4 (EU-024); Fluidized Bed Dryer/Cooler with Baghouse (EU-025); “A” System with Roto-clone No. 6 (EU-054); and “C” System with Roto-clone No. 7 (EU-055). If the Department has reason to believe that the particulate weight emission standard applicable to the emission unit is not being met, it shall require that compliance be demonstrated by the test method specified in the applicable rule. [Rule 62-297.620(4), F.A.C. and 62-4.070(3), F.A.C.]

15. **Test Procedures:**
   a. Tests shall be conducted in accordance with the applicable requirements specified in Appendix CT (Compliance Testing Requirements).
   b. The minimum observation period for a visible emissions compliance test shall be 30 minutes.
   c. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
   d. The permittee shall record the actual sugar processing rate for the emissions units being controlled and tested.

   [Rule 62-297.310, F.A.C. and Permit No.: 0990005-021-AC]

16. **Test Notification:** At least 15 days prior to the date on which each formal compliance test is to begin, the permittee shall notify the Compliance Authority of: the test to be conducted; the date, time and the place of the test; and the contact person who will be responsible for coordinating and having the test conducted.

   [Permit No. 0990005-021-AC; Rule 62-297.310(7), F.A.C.]

**RECORDKEEPING AND REPORTING REQUIREMENTS**

17. **Test Reports:** For each visible emissions test conducted, the permittee shall submit a test report to each Compliance Authority as soon as practical, but no later than 45 days after the last sampling run of each test is completed. Each test report shall include the information specified in Rule 62-297.310(8), F.A.C. [Rule 62-297.310(8), F.A.C. and Permit No. 0990005-021-AC]

18. **Operational Data:** The permittee shall maintain daily and weekly records to demonstrate compliance with the permit limitations specified in Specific Condition No. 3 of this permit. The daily and weekly records shall include, at a minimum, the following: the date; the hours of operation; the total refined sugar produced; the refined sugar produced from the fluidized bed sugar drying system; the refined sugar production from the rotary sugar dryer system (including coolers); quantity of refined sugar handled through the bulk load out area; quantity of refined sugar handle through the transshipment load out area; weekly use of isopropyl alcohol and organic ethanol; and weekly rolling consecutive 52-week period total for all permitted refined sugar production limits. [Rule 62-4.070(3), F.A.C. and Permit No. 0990005-021-AC and -027-AC].
This section of the permit addresses the following emissions units.

<table>
<thead>
<tr>
<th>ID</th>
<th>Emission Unit Description</th>
<th>ID</th>
<th>Emission Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>018</td>
<td>Central vacuum system No. 1</td>
<td>045</td>
<td>Powdered sugar dryer/cooler, packaging Line 8A and 8B</td>
</tr>
<tr>
<td>019</td>
<td>Sugar packaging Lines 0-9, including 8A and 8B</td>
<td>046</td>
<td>Powdered sugar hopper</td>
</tr>
<tr>
<td>020</td>
<td>Sugar grinder</td>
<td>047</td>
<td>Sugar packaging lines (12-14)</td>
</tr>
<tr>
<td>030</td>
<td>Sugar silos Nos. 1, 2, and 3 (Points #1101-1103)</td>
<td>049</td>
<td>Baghouse (Currently inactive)</td>
</tr>
<tr>
<td>031</td>
<td>Railcar sugar unloading receiver No. 1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>032</td>
<td>Railcar sugar unloading receiver No. 2</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

[Permitting Note: Permit Nos. 0990005-019-AC and 0990005-023-AC re-defined the equipment and capacity of the transshipment facility.]

**Process Description**

Sugar received at the transshipment facility is either directly packaged or temporarily stored before packaging. Extra-fine granulated sugar from the refinery is delivered to the transshipment facility at one of three locations. At the east truck receiving dock, trucks are pneumatically unloaded into a main sugar receiver, which pneumatically transfers sugar into surge bins above the packaging lines. At the north side of the facility, trucks are unloaded at a bulk receiving station by locking a boot mechanism against the truck’s hopper and sugar is transferred from trucks by screw conveyors to a bucket elevator feeding one of three storage silos (EU-030). At the north railcar receiving station just west of the sugar silos, railcars will be pneumatically unloaded into two sugar receivers (EU-031 and EU-032) for transfer by screw conveyor to a bucket elevator feeding one of three storage silos. Each sugar receiver is controlled by a baghouse. The west receiver will also transfer sugar directly to a surge bin for packaging line “0”, which will be used to fill totes north of packaging line “1” in the existing packaging room.

Each of the three storage silos (EU-030) is 12 feet in diameter of 12 feet, 68 feet tall, and has a volume of approximately 4,600 cubic feet. Each silo is controlled by a baghouse. Sugar is transferred from each silo by screw conveyor into surge bins located above packaging lines.

Sugar is packaged in one of 14 packaging lines, which are controlled by baghouse systems (Lines 0-8A and 8B-9 (EU-019), Lines 12, 13 and 14 (EU-047). Packaging Lines 8A and 8B vent to the baghouses associated with EU-019 and EU-045. Packaging Line 11 vents to the main sugar receiver. Baghouse (EU-049) is currently inactive. Sugar is metered from surge bins above the packaging lines for processing into a variety of packages and containers for wholesale and retail distribution.

The Trans-Shipment Facility, Packaging line 10 Baghouse is EXEMPT (Permit No. 0990005-029-AC and -030-AC) as it is vented to outside of the refinery building with minimal emissions. (The total emissions from this baghouse is calculated at 0.15 pound/hr. and 0.64 tons/year).

A small portion of extra-fine granulated sugar is conveyed to the sugar grinder (EU-020) and mixed with starch to produce powdered sugar. The sugar grinder is used to reduce the sugar solids to a desired particle size. The grinder has a design capacity of approximately 4 tons per hour. The powdered sugar dryer/cooler (EU-045) and the powdered sugar hopper (EU-046) are also used in this process. In addition, brown sugar may be produced by mixing light or dark molasses with the extra fine granulated sugar. All units are controlled by baghouse systems.
A central vacuum system (EU-018) is used periodically for housekeeping purposes. The system includes various pick-up points throughout the transshipment facility and is equipped with a cyclonic separator followed by a baghouse. The system has no restrictions on the number or types of pick-up points.

### EQUIPMENT SPECIFICATIONS

1. **Baghouse Design Specifications**: Each of the following emissions units shall be controlled by a baghouse that is designed, operated, and maintained to achieve the particulate matter baghouse design specification (grains/scf) identified in the following table.

<table>
<thead>
<tr>
<th>ID</th>
<th>Emission Unit Description</th>
<th>Baghouse Specification a grains/scf</th>
<th>Exhaust Rate scfm</th>
<th>Stack/Vent Height Feet</th>
<th>Maximum Emissions b lb/hour</th>
<th>Maximum Emissions b tons/year</th>
</tr>
</thead>
<tbody>
<tr>
<td>018</td>
<td>Central vacuum system No. 1</td>
<td>0.01</td>
<td>280</td>
<td>8</td>
<td>0.024</td>
<td>0.11</td>
</tr>
<tr>
<td>019</td>
<td>Sugar packaging Lines 0-9, including 8A and 8B</td>
<td>0.01</td>
<td>9869</td>
<td>27</td>
<td>0.85</td>
<td>3.71</td>
</tr>
<tr>
<td>020</td>
<td>Sugar grinder</td>
<td>0.0005</td>
<td>2961</td>
<td>39</td>
<td>0.013</td>
<td>0.06</td>
</tr>
<tr>
<td>030</td>
<td>Sugar silo No. 1 (Point #S1101)</td>
<td>0.02</td>
<td>500</td>
<td>65</td>
<td>0.086</td>
<td>0.38</td>
</tr>
<tr>
<td>031</td>
<td>Sugar silo No. 2 (Point #S1102)</td>
<td>0.02</td>
<td>500</td>
<td>65</td>
<td>0.086</td>
<td>0.38</td>
</tr>
<tr>
<td>032</td>
<td>Sugar silo No. 3 (Point #S1103)</td>
<td>0.02</td>
<td>500</td>
<td>65</td>
<td>0.086</td>
<td>0.38</td>
</tr>
<tr>
<td>031</td>
<td>Railcar unloading receiver No. 1</td>
<td>0.02</td>
<td>615</td>
<td>5</td>
<td>0.11</td>
<td>0.46</td>
</tr>
<tr>
<td>032</td>
<td>Railcar unloading receiver No. 2</td>
<td>0.02</td>
<td>615</td>
<td>5</td>
<td>0.11</td>
<td>0.46</td>
</tr>
<tr>
<td>045</td>
<td>Powdered sugar dryer/cooler, packaging Lines 8A and 8B</td>
<td>0.01</td>
<td>8640</td>
<td>48</td>
<td>0.74</td>
<td>3.24</td>
</tr>
<tr>
<td>046</td>
<td>Powdered sugar hopper</td>
<td>0.01</td>
<td>1728</td>
<td>42</td>
<td>0.15</td>
<td>0.68</td>
</tr>
<tr>
<td>047</td>
<td>Sugar packaging Lines 12, 13 and 14</td>
<td>0.01</td>
<td>3629</td>
<td>48</td>
<td>0.49</td>
<td>2.16</td>
</tr>
<tr>
<td>049</td>
<td>Baghouse (currently inactive)</td>
<td>0.02</td>
<td>2212</td>
<td>9</td>
<td>0.38</td>
<td>1.66</td>
</tr>
</tbody>
</table>

a. New and replacement bags shall meet these specifications based on vendor information. No particulate matter emissions tests are required.

b. These rates represent the maximum expected emissions based on the baghouse design specification, the maximum exhaust flow rates, and 8,760 hours of operation per year. These rates are not enforceable emissions standards.

[Permit Nos. 0990005-019-AC and 0990005-023-AC]

### CAPACITY AND PERFORMANCE RESTRICTIONS

2. **Permitted Capacity**: The maximum sugar packaging rate is 1,300 tons per day. [ Permit Nos. 0990005-019-AC and 0990005-023-AC and Title V application received May 15, 2012; Rule 62-210.200 (PTE), F.A.C.]

3. **Restricted Operation**: The hours of operation are not limited (8,760 hours per year). [Permit Nos. 0990005-019-AC and 0990005-023-AC; and Rule 62-210.200 (PTE), F.A.C.]
EMISSION LIMITING STANDARDS

4. Opacity Standard: As determined by EPA Method 9 observations, visible emissions from each baghouse exhaust point shall not exceed 5 percent opacity. [Permit Nos. 0990005-019-AC and 0990005-023-AC; and Rule 62-4.070(3), F.A.C.]

TESTING

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

6. Tests Prior to Renewal: Within the 12-month period prior to renewing the operation permit, each baghouse exhaust point shall be tested to demonstrate compliance with the specified opacity standard. [Rule 62-297.310(7)(a)3, F.A.C.]

7. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required test. [Rule 62-297.310(7)(a)9, F.A.C.]

8. Test Method: All tests shall be conducted in accordance with EPA Method 9, which is described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Tests shall also comply with the applicable requirements of Rule 62-297.310, F.A.C. See Appendix CT. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

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

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

RECORD KEEPING AND REPORTING

11. Test Reports: For each visible emissions test conducted, the permittee shall file a test report including the information specified in Rule 62-297.310(8), F.A.C. with the Compliance Authority as soon as practical, but no later than 45 days after the last sampling run of each test is completed. See Appendix CT in Section 4 of this permit. [Rules 62-297.310(8), F.A.C.]

12. Operational Data: The permittee shall maintain daily and monthly records to demonstrate compliance with the specified maximum sugar packaging rate. [Permit Nos. 0990005-019-AC and 0990005-023-AC; and Rule 62-4.070(3), F.A.C.]

OTHER APPLICABLE REQUIREMENTS

13. Compliance Plan: The permittee shall comply with the provisions of the Compliance Plan as specified in Appendix CP in Section 4 of this permit. [Rule 62-213.440(2), F.A.C.]
This subsection addresses the following emissions units.

ARMS ID No. 0990332 - New Hope Power Company’s Okeelanta Cogeneration Plant

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
<th>Process Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>005</td>
<td>Distillate Oil Storage Tank (50,000 gallons)</td>
<td>Cogeneration Plant</td>
</tr>
</tbody>
</table>

ARMS ID No. 0990005 – Okeelanta Corporation’s Sugar Mill and Refinery

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
<th>Process Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>015</td>
<td>Distillate Oil Storage Tank - (DELETED)</td>
<td>Sugar Mill and Refinery</td>
</tr>
<tr>
<td>016</td>
<td>Distillate Oil Storage Tank, - (DELETED)</td>
<td>Sugar Mill and Refinery</td>
</tr>
<tr>
<td>017</td>
<td>Distillate Oil Storage Tank - (DELETED)</td>
<td>Sugar Mill and Refinery</td>
</tr>
<tr>
<td>040</td>
<td>Facility Fuel Tank Farm</td>
<td>Facility</td>
</tr>
</tbody>
</table>

EQUIPMENT CAPACITIES AND PERFORMANCE RESTRICTIONS

1. Oil Storage Tanks:
   a. ARMS ID No. 0990332: The distillate oil storage tank (EU-005) has a capacity of 50,000 gallons. [Permit No. 0990005-016-AC]
   b. Miscellaneous tanks installed on or before July 23, 1984 are not subject to the NSPS Subpart Kb provisions in 40 CFR 60. Fuel and oil tanks with a storage capacity of 19,813 gallons or less are not subject to NSPS Subpart Kb provisions. Fuel and oil tanks with a storage capacity between 19,813 gallons and 39,890 gallons shall store only volatile organic liquids with a maximum true vapor pressure of less than 15.0 kilopascals (kPa) or 2.17 pounds per square inch, absolute (psia). Fuel and oil tanks with a storage capacity of 39,890 gallons or more shall store only volatile organic liquids with a maximum true vapor pressure of less than 3.5 kPa (0.51 psia). This condition ensures that the storage tanks are not subject to the NSPS Subpart Kb provisions in 40 CFR 60. [NSPS Subpart Kb, §60.110b] [Rule 62-210.200 (PTE), F.A.C.]

RECORDS

2. Records: The permittee shall maintain records of the types and amounts of fuel stored in each tank. Distillate oil shall meet the requirements of the Ash and Fuel Management Plans in Appendix AM and FM of this permit. [Rule 62-4.070(3), F.A.C.]
This permit addresses the following emissions unit:

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
<th>Process Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>048</td>
<td>Paint Booth</td>
<td>Okeelanta Shop</td>
</tr>
</tbody>
</table>

**Permitting Note:** Permit No. 0990005-015-AC redefined this emissions unit. The paint spray booth is the drive-through model of the Crossflo truck spray booth manufactured by AFC, Inc. (Model Number TSD6036). The paint booth has the potential to emit 9.40 tons per year of volatile organic compound (VOC), 0.47 tons per year of hazardous air pollutants (HAPs), and 0.35 tons per year of particulate matter (PM/PM<sub>10</sub>).

**EQUIPMENT SPECIFICATIONS**

1. **Method of Operation.** Paint shall only be applied to agricultural equipment, trailers, and other vehicles or facility equipment. Paint shall be applied by compressed air spray gun, airless paint sprayer or other equipment with equivalent transfer efficiency. Compressed air systems typically use house air within a pressure range of approximately 60 to 80 pounds per square inch (psi). Airless systems typically 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 flow rate of 45,500 actual cubic feet per minute (acfm).

2. **Hours of Operation:** The hours of operation for this emissions unit are not restricted (8,760 hours per year).

3. **Permitted Capacity:** The maximum throughput rate of paint and thinner shall not exceed 4,950 gallons in any consecutive 12 months.

4. **VOC Emissions:** Emissions of volatile organic compounds (VOC) shall not exceed 9.40 tons in any consecutive 12 months. The permittee may adjust the amounts and types of coatings used as necessary to comply with this standard. Coatings and thinners used in the spray booth are not restricted to specific products or manufacturers. The permittee may substitute coatings and thinners and adjust the amounts of coatings and thinners used, as needed.

5. **Visible Emissions:** Visible emissions from the paint spray booth shall not exceed 20 percent opacity.

6. **Fugitive VOC:** All equipment, pipes, hoses, containers, lids, fittings, etc., shall be operated and maintained in such a manner as to minimize leaks, fugitive emissions, and spills of materials containing volatile organic compounds (VOC).

**TESTING**

7. **Special Compliance Tests:** In accordance with Rule 62-297.310(7)(b), F.A.C., the Compliance Authority may require a compliance test for visible emissions.

**RECORD KEEPING AND REPORTING**

8. **Operational Records:** For each month, the permittee shall record and maintain records of the following: the number of actual hours of operation for the paint booth; the dates of operation; the amounts and types of coatings, thinners and cleanup solvents used; and a monthly calculation of the volatile organic compounds and hazardous air pollutants emitted from the paint booth. VOC/HAP emissions shall be calculated by
assuming that all VOC/HAP in the coatings, thinners and cleanup solvents evaporate. The mass fraction of VOC/HAP from each solvent-containing material shall be determined from the Material Safety Data Sheets (MSDS) supplied by the vendors. The permittee shall maintain a file of MSDS for each solvent-containing material that indicates the composition of the VOC/HAP. Solvent-containing materials include, but are not limited to, powder coatings, solvent coatings, thinners, and cleanup solvents. The file must be maintained on site and made available for inspection upon request. The permittee shall have until the last day of the following month to complete these records. The amounts and types of coatings used and the calculated VOC and HAP emissions shall be included in the required Annual Operating Report. [Permit 0990005-015-AC; Rules 62-210.370 and 62-4.070(3), F.A.C.]
Appendix AM. Ash Management Plan
Appendix CF. Citation Format and Glossary
Appendix CM. Compliance Assurance Monitoring Plan
Appendix CP. Compliance Plan
Appendix CT. Common Testing Requirements
Appendix FM. Fuel Management Plan
Appendix GC. Good Combustion Plan, Cogeneration Boilers
Appendix HI. Permit History
Appendix OM. Operation and Maintenance Plans, Cogeneration Boilers
Appendix QR. Quarterly Report, Cogeneration Boilers
Appendix SS. Summary of Standards
Appendix TV. Title V Conditions
Appendix UI. List of Unregulated and Insignificant Emissions Units and/or Activities
Appendix 60A. NSPS Subpart A, General Provisions
Appendix 60Da. NSPS Subpart Da, Electric Utility Steam Generating Units
Appendix 60Db. NSPS Subpart Db, Industrial Boilers and Process Heaters
Appendix 60Ea. NSPS Subpart Ea, Applicability for Municipal Waste Combustors
ASH MANAGEMENT PLAN

This Appendix identifies and describes the practices for managing, sampling, and analyzing ash generated from the boilers operating at this plant. Enforceable “permit conditions” are specified at the end of this Appendix.

Ash from Bagasse and Wood Combustion

Bottom Ash

Bottom ash is discharged continuously from each boiler into three, water-submerged drag chain conveyors. Each conveyor consists of a wet upper compartment and a dry lower compartment. The upper compartment has a water-tight steel trough designed to contain the water required for quenching and cooling the bottom ash to 140º F and is sized to accommodate and store up to two hours of bottom ash generated from the wood or bagasse.

The submerged chain conveyor has a removal rate of 8 TONS/HOUR (TPH). An integrated water supply and recirculation system is used. Over flow water from the submerged dry chain conveyor trough, hopper seal trough, and dewatered ash storage pile is piped back to a recirculation sump equipped with an overflow weir and a return sump pump. Make-up water is added to the recirculation sump to replace water lost in the dewatered ash and through evaporation. The bottom ash is then transferred to an enclosed mixed ash belt conveyor for transfer to the mixed ash bunker.

Fly Ash

Fly ash consists of ash collected in air heater hoppers, dust collector hoppers, and from ESP hoppers. Fly ash is transferred by screw conveyors from each system and is wetted prior to transfer to the enclosed mixed ash belt conveyor that transfers it to the mixed ash bunker. All of the fly ash and dust collector ash conveyors are enclosed.

Mixed Ash Bunker

The mixed ash bunker is a 3-sided bunker sized to accommodate about a seven-day ash capacity. At this point the ash is extremely wet. Under normal operating procedures, the ash is 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. A front-end loader is used to reclaim and load the stored ash into trucks.

Ash Disposal

All ash generated by the facility is taken to a Class I landfill for disposal.

Quality Control Measures

Samples of mixed bottom and fly ash are obtained from the storage bunker weekly for four weeks. Each weekly sample is a composite of mixed ash grab samples from three to five locations of the ash piles in the storage bunker. After collection of the composite sample in the fourth week, the monthly sample is prepared for analysis by mixing equal portions of the four weekly mixed ash samples. A portion of the monthly composite mixed ash sample is retained as a control sample for verification of the lab test results, if necessary.

If the fly ash is being collected in the silo, weekly fly ash grab samples are obtained from the transfer point between the collecting fly ash chain conveyor and the bucket elevator conveyor, as ash is loaded into the silo. Additionally, grab samples of the bottom ash are obtained weekly from the bottom ash piles in the storage bunker. The individual sample size for the bottom ash and fly ash grab samples is approximately one pound each.

Prior to releasing the ash samples for outside lab analysis, a “combined ash sample” for the facility is also 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 is retained on site as control samples for
verification of lab test results, if necessary.

The monthly ash samples are 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 are typically be available to the plant Environmental Coordinator or Fuels Manager within one week after receipt of the sample at the lab. Any results on the representative monthly composite ash sample which indicate the burning of wood material with concentrations of copper, chromium and/or arsenic above the air permit limits are investigated by the plant Environmental Coordinator or Fuels Manager. Retesting 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 material provide for an accurate representation of the composition of the wood material burned at the facility.

**Correlation of Wood/Ash Analytical Results**

In conjunction with the analytical results of the mixed ash samples, results from the wood samples shall be used to evaluate the effectiveness of the fuel management program in removing chemically treated wood (e.g., copper, chromium and arsenic) from the biomass fuel.

**Air Permit Conditions**

1. **Ash - Sampling and Analysis:** At least once each month, the permittee shall have an analysis conducted on a composite sample of fly ash and bottom ash (mixed 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. [Permit No. PSD-FL-196(P); Rule 62-4.070(3), F.A.C.]

2. **Ash - Quarterly Reports:** Within 30 days following each calendar quarter, the permittee shall submit to the Compliance Authority a summary of the monthly mixed ash analyses and a summary of the ultimate disposal of any off-specification material. [Rule 62-4.070(3), F.A.C.]

**Palm Beach County Zoning Requirements for Ash Management**

3. The Zoning Plan approved by Palm Beach County requires that New Hope Power Company revise the ash management plan to incorporate the revised testing procedures for the ash as submitted to the Palm Beach County Health Department. The New Hope Power Company must also request that the revised ash management plan be included in the Title V operating permit (Petition DOA 1992-014B and Condition 11 of Resolution R-2004-1372). This Appendix AM of the Title V permit satisfies the County requirement.
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
“A" 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

GLOSSARY OF TERMS:
° F: degrees Fahrenheit
acfm: actual cubic feet per minute
AOR: Annual Operating Report

ARMS: Air Resource Management System (Department’s database)
BACT: Best Available Control Technology
Btu: British thermal units
CAM: compliance assurance monitoring
CEMS: continuous emissions monitoring system
cfm: cubic feet per minute
CFR: Code of Federal Regulations
CO: carbon monoxide
COMS: continuous opacity monitoring system
DARM: Division of Air Resource Management
DCA: Department of Community Affairs
DEP: Department of Environmental Protection
Department: Department of Environmental Protection
dscfm: dry standard cubic feet per minute
EPA: Environmental Protection Agency
ESP: electrostatic precipitator
EU: emissions unit
F.A.C.: Florida Administrative Code
F.D.: forced draft
F.S.: Florida Statutes
FGR: flue gas recirculation
Fl: fluoride
ft²: square feet
ft³: cubic feet
gpm: gallons per minute
gr: grains
HAP: hazardous air pollutant
Hg: mercury
I.D.: induced draft
ID: identification
ISO: International Standards Organization (refers to those conditions at 288 Kelvin, 60% relative humidity and 101.3 kilopascals pressure.)
kPa: kilopascals
LAT: latitude
lb: pound
lb/hr: pounds per hour
LONG: longitude
MACT: maximum achievable technology
mm: millimeter
MMBtu: million British thermal units
MSDS: material safety data sheets
MW: megawatt
NESHAP: National Emissions Standards for Hazardous Air Pollutants
NOx: nitrogen oxides
NSPS: New Source Performance Standards
O&M: operation and maintenance
O₂: oxygen
ORIS: Office of Regulatory Information Systems
OS: organic solvent
Pb: lead
PM: particulate matter
PM₁₀: particulate matter with a mean aerodynamic diameter of 10 microns or less
PSD: prevention of significant deterioration
psi: pounds per square inch
PTE: potential to emit
RACT: reasonably available control technology
RATA: relative accuracy test audit
RMP: Risk Management Plan
RO: responsible official
SAM: sulfuric acid mist
scf: standard cubic feet
scfm: standard cubic feet per minute
SIC: standard industrial classification code
SNCR: selective non-catalytic reduction
SOA: Specific Operating Agreement
SO₂: sulfur dioxide
TPH: tons per hour
TPY: tons per year
UTM: Universal Transverse Mercator coordinate system
VE: visible emissions
VOC: volatile organic compounds
x: by or times
Pursuant to Rule 62-213.440(1)(b)1.a., F.A.C., the CAM plans that are included in this appendix contain the monitoring requirements necessary to satisfy 40 CFR 64. Conditions 1-17 are generic conditions applicable to all emissions units that are subject to the CAM requirements. Specific requirements related to each emissions unit are contained in the attached tables.

**40 CFR 64.6 Approval of Monitoring**

1. **Plans:** The attached CAM plans are approved for the purposes of satisfying the requirements of 40 CFR 64.3. [40 CFR 64.6(a)]

2. **Contents:** The attached CAM plans include the following information:
   a. The indicators to be monitored (such as temperature, pressure drop, emissions, or similar parameter);
   b. The means or device to be used to measure the indicators (such as temperature measurement device, visual observation, or CEMS); and
   c. The performance requirements established to satisfy 40 CFR 64.3(b) or (d), as applicable. [40 CFR 64.6(c)(1)]

3. **Excursions:** The attached CAM plans describe the means by which the owner or operator will define an exceedance of the permitted limits or an excursion from the stated indicator ranges and averaging periods for purposes of responding to (see CAM Conditions 5-9) and reporting exceedances or excursions (see CAM Conditions 10-14). [40 CFR 64.6(c)(2)]

4. **Required Monitoring:** The permittee is required to conduct the monitoring specified in the attached CAM plans and shall fulfill the obligations specified in the conditions below (see CAM Conditions 5-17.). [40 CFR 64.6(c)(3)]

**40 CFR 64.7 Operation of Approved Monitoring**

5. **Commencement of Operation:** The owner or operator shall conduct the monitoring required under this appendix upon the effective date of this Title V permit. [40 CFR 64.7(a)]

6. **Proper Maintenance:** At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment. [40 CFR 64.7(b)]

7. **Continued Operation:** Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. [40 CFR 64.7(c)]

8. **Response to Excursions or Exceedances:**
   a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to
restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions, if allowed by this permit). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

b. Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[40 CFR 64.7(d)(1) and (2)]

9. Documentation of Need for Improved Monitoring: If the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the Title V permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. [40 CFR 64.7(e)]

40 CFR 64.8 Quality Improvement Plan (QIP) Requirements

10. Triggering a QIP: Based on the results of a determination made under CAM Condition 8.b., above, the permitting authority may require the owner or operator to develop and implement a QIP. Consistent with CAM Condition 4., an accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period, may require the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices. [40 CFR 64.8(a)]

11. Elements of a QIP:

a. The owner or operator shall maintain a written QIP, if required, and have it available for inspection.

b. The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

(i) Improved preventive maintenance practices.

(ii) Process operation changes.

(iii) Appropriate improvements to control methods.

(iv) Other steps appropriate to correct control performance.

(v) More frequent or improved monitoring (only in conjunction with one or more steps under CAM Condition 11.b(i) through (iv), above).

[40 CFR 64.8(b)]

12. QIP Notification: If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the permitting authority if the period for completing the
improvements contained in the QIP exceeds 180 days from the date on which the need to implement the
QIP was determined. [40 CFR 64.8(c)]

13. **Revised QIP:** Following implementation of a QIP, upon any subsequent determination pursuant to CAM
Condition 8.b., the permitting authority may require that an owner or operator make reasonable changes to
the QIP if the QIP is found to have:
   a. Failed to address the cause of the control device performance problems; or
   b. Failed to provide adequate procedures for correcting control device performance problems as
      expeditiously as practicable in accordance with good air pollution control practices for minimizing
      emissions.
      [40 CFR 64.8(d)]

14. Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any
existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping
requirement that may apply under federal, state, or local law, or any other applicable requirements under
the Act. [40 CFR 64.8(e)]

**40 CFR 64.9 Reporting And Recordkeeping Requirements**

15. **General Reporting Requirements:**
   a. Commencing from the effective date of this permit, the owner or operator shall submit monitoring
      reports semi-annually to the permitting authority in accordance with Rule 62-213.440(1)(b)3.a.,
      F.A.C.
   b. A report for monitoring under this part shall include, at a minimum, the information required under
      Rule 62-213.440(1)(b)3.a., F.A.C., and the following information, as applicable:
      (i) Summary information on the number, duration and cause (including unknown cause, if
          applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
      (ii) Summary information on the number, duration and cause (including unknown cause, if
          applicable) for monitor downtime incidents (other than downtime associated with zero and
          span or other daily calibration checks, if applicable); and
      (iii) A description of the actions taken to implement a QIP during the reporting period as specified
          in CAM Conditions 10-14. Upon completion of a QIP, the owner or operator shall include in
          the next summary report documentation that the implementation of the plan has been
          completed and reduced the likelihood of similar levels of excursions or exceedances occurring.
      [40 CFR 64.9(a)]

16. **General Recordkeeping Requirements:**
   a. The owner or operator shall comply with the recordkeeping requirements specified in Rule 62-
      213.440(1)(b)2., F.A.C. The owner or operator shall maintain records of monitoring data, monitor
      performance data, corrective actions taken, any written quality improvement plan required pursuant
      to CAM Conditions 10-14 and any activities undertaken to implement a quality improvement plan,
      and other supporting information required to be maintained under this part (such as data used to
      document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).
   a. The owner or operator shall comply with the recordkeeping requirements specified in Rule 62-
      213.440(1)(b)2., F.A.C. The owner or operator shall maintain records of monitoring data, monitor
      performance data, corrective actions taken, any written quality improvement plan required pursuant
      to CAM Conditions 10-14 and any activities undertaken to implement a quality improvement plan,
and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

b. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements. [40 CFR 64.9(b)]

### 40 CFR 64.10  Savings Provisions

17. **Savings Provisions:** It should be noted that nothing in this appendix shall:

a. Excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. The requirements of this appendix shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purpose of determining the monitoring to be imposed under separate authority under the Act, including monitoring in permits issued pursuant to title I of the Act. The purpose of this part is to require, as part of the issuance of a permit under Title V of the Act, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of this part.

b. Restrict or abrogate the authority of the Administrator or the permitting authority to impose additional or more stringent monitoring, recordkeeping, testing, or reporting requirements on any owner or operator of a source under any provision of the Act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable.

c. Restrict or abrogate the authority of the Administrator or permitting authority to take any enforcement action under the Act for any violation of an applicable requirement or of any person to take action under section 304 of the Act.

[40 CFR 64.10]

**Units:** Cogeneration Boilers (EU-001, 002, and 003)

**Pollutant:** Particulate Matter (PM)

**Standard:** PM ≤ 0.026 lb/MMBtu (Opacity limited to ≤ 20%, except for one 6-minute block per hour ≤ 27%)

**Control:** Mechanical Dust Collectors and Electrostatic Precipitator (ESP)

<table>
<thead>
<tr>
<th>Parametric Criteria</th>
<th>Indicator</th>
</tr>
</thead>
<tbody>
<tr>
<td>Indicator</td>
<td>Opacity</td>
</tr>
<tr>
<td>Measurement Approach</td>
<td>Data from the continuous opacity monitoring system (COMS) shall be used to determine potential emissions excursions.</td>
</tr>
<tr>
<td>Indicator Range</td>
<td><strong>An excursion is any 1-hour average of 15% opacity or more.</strong> An excursion requires documentation, investigation, and corrective action.</td>
</tr>
<tr>
<td>Data Representativeness</td>
<td>Opacity levels are determined in the stack. A sustained step increase of opacity may be related to higher particulate matter emissions resulting from problems with the boiler or control equipment.</td>
</tr>
<tr>
<td>QA/QC Practices</td>
<td>The COMS shall be maintained and calibrated in accordance with the applicable requirements of the permit and 40 CFR 60.</td>
</tr>
<tr>
<td>Monitoring Frequency</td>
<td>The COMS shall continuously report opacity and determine a 1-hour block average from the average of all valid 1-minute averages collected during the period.</td>
</tr>
<tr>
<td>----------------------</td>
<td>--------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Data Collection Procedures</td>
<td>The COMS shall continuously report opacity and determine a 1-hour block average.</td>
</tr>
<tr>
<td>Averaging Period</td>
<td>1-hour block average</td>
</tr>
</tbody>
</table>

**OKEELANTA CORPORATION SUGAR MILL AND REFINERY (FACILITY ID NO. 0990005)**

In accordance with the supplemental application received on March 12, 2010, the applicant identified the following items for which compliance was not yet determined.

(Note: Boiler No. 16 (EU-014) has been removed and is therefore DELETED per permit No. 0990005-032-AV)

**Railcar Receiver No. 1 (EU-031) – (Currently inactive)**

**Railcar Receiver No. 2 (EU-032)**

**Permit No. 0990005-023-AC**

*Deviation:* Condition 13 in Subsection 3A requires annual compliance tests for opacity on the associated baghouse vent. The last test was conducted on September 8, 2006 because of lack of operation.

*Underlying Cause:* It has not been necessary to operate this emissions unit.

*Plan:* In accordance with the requirements of Rule 62-210.300(5), F.A.C., the permittee shall provide a 60-day advance notification of its intent to restart this unit. The permittee shall conduct the required compliance test within 30 days of restarting the unit.

**Rotary Dryer with Rotoclone No. 1 (EU-021)**

**Permit No. 0990005-021-AC**

*Deviation:* Condition III. 10 of this permit requires initial and subsequent annual compliance tests for opacity. Initial opacity tests were not conducted on the rotary dryer with Rotoclone No. 1 because it was not in operation for the initial tests on equipment at the Transshipment Facility. In addition, this unit has not operated during the current federal fiscal year or the previous two federal fiscal years.

*Underlying Cause:* The unit has had limited operation.

*Plan:* In accordance with the requirements of Rule 62-210.300(5), F.A.C., the permittee shall provide a 60-day advance notification of its intent to restart this unit. The permittee shall conduct the required compliance test within 30 days of restarting the unit.

**Sugar Packaging Lines 0-9 (EU-019)**

*Note:* In 2011, Okeelanta certified three (3) personnel to perform VE testing to resolve problems. From Feb. 13, 2010 to date, there have been no issues dealing with exceeding the allowable operating rate for this EU-019 based upon the latest testing. The unit was tested at maximum capacity of 1244 tons per year (TPY). Therefore it is determined that the subject of EU-019, is **NOT** required for this compliance plan.
Unless otherwise specified by permit, all emissions units that require testing are subject to the following conditions as applicable.

1. **Required Number of Test Runs:** For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

2. **Operating Rate During Testing:** 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 impracticable 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.
   a. **Combustion Turbines.** (Reserved)
   b. **All Other Sources.** Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit.
   [Rule 62-297.310(2), F.A.C.]

3. **Calculation of Emission Rate:** For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

4. **Applicable Test Procedures:**
   a. **Required Sampling Time.**
      1) Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
      2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
         a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

c. *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.

d. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.

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

<table>
<thead>
<tr>
<th>ITEM</th>
<th>MINIMUM CALIBRATION FREQUENCY</th>
<th>REFERENCE INSTRUMENT</th>
<th>TOLERANCE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquid in glass thermometer</td>
<td>Annually</td>
<td>ASTM Hg in glass ref. thermometer or equivalent or thermometric points</td>
<td>+/-2%</td>
</tr>
<tr>
<td>Bimetallic thermometer</td>
<td>Quarterly</td>
<td>Calib. liq. in glass</td>
<td>5° F</td>
</tr>
<tr>
<td>Thermocouple</td>
<td>Annually</td>
<td>ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer</td>
<td>5° F</td>
</tr>
<tr>
<td>Barometer</td>
<td>Monthly</td>
<td>Hg barometer or NOAA station</td>
<td>+/-1% scale</td>
</tr>
<tr>
<td>Pitot Tube</td>
<td>When required or when damaged</td>
<td>By construction or measurements in wind tunnel D greater than 16″ and standard pitot tube</td>
<td>See EPA Method 2, Fig. 2-2 &amp; 2-3</td>
</tr>
<tr>
<td>Probe Nozzles</td>
<td>Before each test or when nicked, dented, or corroded</td>
<td>Micrometer</td>
<td>+/- 0.001” mean of at least three readings; Max. deviation between readings, 0.004”</td>
</tr>
<tr>
<td>Dry Gas Meter and Orifice Meter</td>
<td>1. Full Scale: When received, when 5% change observed, annually</td>
<td>Spirometer or calibrated wet test or dry gas test meter</td>
<td>2%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2. One Point: Semiannually</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>3. Check after each test series</td>
<td>5%</td>
</tr>
</tbody>
</table>
SECTION 4. APPENDIX CT
Common Testing Requirements

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

5. 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.]

6. Required Stack Sampling Facilities: Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.
   a. Permanent Test Facilities. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.
   b. Temporary Test Facilities. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.
   c. Sampling Ports.
      1) All sampling ports shall have a minimum inside diameter of 3 inches.
      2) The ports shall be capable of being sealed when not in use.
      3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.
      4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.
      5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.
d. **Work Platforms.**
   1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.
   2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.
   3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.
   4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. **Access to Work Platform.**
   1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.
   2) Walkways over free-fall areas shall be equipped with safety rails and toeboards.

f. **Electrical Power.**
   1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.
   2) If extension cords are used to provide the electrical power, they shall be kept on the plant’s property and be available immediately upon request by sampling personnel.

g. **Sampling Equipment Support.**
   1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.
      a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.
      b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.
      c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.
   2) A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.
   3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

7. **Frequency of Compliance Tests:** The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
a. General Compliance Testing.

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

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

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

a) Did not operate; or

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

4) During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a) Visible emissions, if there is an applicable standard;

b) Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c) Each NESHAP pollutant, if there is an applicable emission standard.

5) An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

6) For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

7) For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

8) Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9) The owner or operator shall notify the Department, at least 15 days prior to the date on which each
formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

10) An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

8. **Test Reports:**

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

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

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

      1) The type, location, and designation of the emissions unit tested.

      2) The facility at which the emissions unit is located.

      3) The owner or operator of the emissions unit.

      4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.

      5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

      6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.

      7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.

      8) The date, starting time and duration of each sampling run.

      9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.

     10) The number of points sampled and configuration and location of the sampling plane.
11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.

12) The type, manufacturer and configuration of the sampling equipment used.

13) Data related to the required calibration of the test equipment.

14) Data on the identification, processing and weights of all filters used.

15) Data on the types and amounts of any chemical solutions used.

16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.

17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.

18) All measured and calculated data required to be determined by each applicable test procedure for each run.

19) The detailed calculations for one run that relate the collected data to the calculated emission rate.

20) The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.

21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

9. The terms stack and duct are used interchangeably in this rule.

[Rule 62-297.310(9), F.A.C.]
**FUEL MANAGEMENT PLAN**

This Appendix identifies and describes the practices for managing, sampling, and analyzing authorized fuels at this plant. Enforceable “permit conditions” are specified at the end of this Appendix.

**BAGASSE**

**Description**

Bagasse is the fibrous vegetative residue remaining after the sugarcane milling process. It is 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 or “crop” season, which is normally from mid-October to April of the following year.

During grinding season, the sugar mill will provide the cogeneration facility with bagasse at an average daily rate of approximately 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. Approximately 50% of the bagasse generated during the grinding season will be fired directly in the cogeneration boilers, while the remaining portion will be stockpiled for use in the off-season.

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.

In the bagasse storage area, front-end loaders are used to reclaim the bagasse fuel and perform pile maintenance. Bagasse fuel is reclaimed from the bagasse storage area by a front-end loader at a design rate of up to 175 tons per hour through the use of one under-pile chain reclaimer. The reclaim conveyor transfers the bagasse to the bagasse Boiler Feed Conveyor that deposits the fuel onto one of two chain distribution conveyors for delivery to the cogeneration boilers.

The entire fuel conveying system is provided with the necessary controls and fire protection systems.

The bagasse pile will be in the location noted on the site plan as fuel storage area. The bagasse will contain moisture 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 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.

**Permit Conditions**

1. **Bagasse - Sampling and Analysis:** At least twice each month, the permittee shall have an analysis conducted on a representative “as-fired” bagasse sample for the following: heating value (modified ASTM D3286, Btu/lb, dry), carbon and ash 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). Samples shall be taken at least two weeks apart. Records of the results of these analyses shall be maintained on site and made available upon request. [Permit No. PSD-FL-196(P); Rule 62-4.070(3), F.A.C.]
2. **Bagasse - Quarterly Report:** Within 30 days following each calendar quarter, the permittee shall submit to the Compliance Authority a summary of the analytical results for the “as-fired” bagasse samples taken during the calendar quarter. [Permit No. PSD-FL-196(P); Rule 62-4.070(3), F.A.C.]

3. **Bagasse - Firing Records:** For the Annual Operating Report, the permittee shall calculate the annual bagasse firing rate based on the following: the summation of bagasse delivered from the mill to the cogeneration plant plus bagasse delivered to the bagasse reclamer scales, minus bagasse measured on the bagasse recycle conveyor to the storage pile. Each value shall be based on the records derived from the in-line belt scale measurements. The total annual heat input rate from steam shall be based on steam production records, the net enthalpy from the steam characteristics, and the boiler thermal efficiencies. The annual heat input from distillate oil shall be based on the gallons of distillate oil fired and the fuel heating values from vendor fuel certifications and sampling/analyses conducted throughout the year. The annual heat input rate from wood shall be determined as described in the next section. [Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.]

**WOOD MATERIAL**

**Description**

During the non-grinding season, normally from April to mid October, the bagasse is no longer produced as a fuel and clean wood material is used as the primary biomass fuel. During the non-grinding season, bagasse is reclaimed from the bagasse storage pile and fed to the boilers to ensure consistent operations. 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 material.

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 is required to 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.

The trucks will be unloaded either by utilizing two hydraulically operated truck dumpers or by means of an unloading area provided to accommodate self-unloading trucks. When using the truck dumpers, the wood material 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 material to the screen and hog tower at a rate up to the design rate of 300 TPH.

The screen and hog tower is an open facility at which the wood material 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 material 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 a rate up to the design rates of 175 TPH of wood chips by two under-pile chain reclaimers. The reclaimed fuel is transferred to the cogeneration facility via the wood Boiler Feed Conveyor and to the boiler feeders by the Chain Distribution Conveyors.

The wood delivered 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. 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 manual fire fighting. Deluge water spray systems will be used for protection of the fuel handling equipment and the conveyors.

The facility fire hydrant loop is located on the north side of the fuel storage area. The facility also has an auxiliary fire water tank, diesel powered fire water pump and fire hydrant located on the northwest corner of the bagasse fuel storage areas. Water wagons from the sugar mill supplement fire protection on the south side of the bagasse fuel storage area. The facility also utilizes a mobile diesel powered irrigation pump which is used for fire protection in the bagasse fuel storage area.

**Quality Control Procedures**

The management program for wood material shall be revised as necessary 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 provides 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.

Wood waste will be supplied to the Project under long-term contracts which include quality requirements reflecting the conditions of the air permit. The wood material specification imposed on the supplier will be:

- Less than 1% by volume or weight shall be plastics, rubber, glass and painted wood.
- 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.
- Less than 5% shall be sand, soil or other organic material
- Moisture content shall be between 20% and 50% with a quarterly average of less than 40%.
- 95% shall be less than 4” in size, 15% (on an individual load) will be less than 1/4” in size.

Okeelanta may 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 material exceeds the specification limits for sand, soil, inorganic material or moisture content, Okeelanta may accept the material provided that the supplier reduces its handling and processing costs by a predetermined rate.

**Supply Sites**

As stipulated in the fuel supply contracts with the wood material suppliers, the delivered wood material 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 material delivered to the plant meets the provisions of the air permit, as well as other fuel quality specifications,
the wood material suppliers will perform inspection and material segregation operations on each load of feedstock received at their facilities. Although the plant will obtain wood material 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 plant.

The bulk material feedstock at the originating wood yards will first undergo a “gross” material separation by removing the bulk wood material 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 material. After this operation, the wood material will be further visually inspected and manually sorted (when applicable) to remove unauthorized materials. The “sorted” wood material is then mechanically sized and screened (to actual contract specifications) prior to delivery to the cogeneration plant.

As a quality assurance measure, each fuel supplier’s operations will be periodically reviewed by cogeneration plant personnel during unannounced site inspections. These visits will allow the cogeneration plant to ensure that the supplier’s inspection and segregation efforts remain at acceptable levels.

Wood Fuel Storage Area

The cogeneration plant will periodically sample and analyze the wood materials. Upon delivery of the wood material to the plant, 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 wood 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 material will occur at the wood fuel storage yard. Samples will be taken from specified sections of the wood pile that are representative of the fuel to be reclaimed and burned during the following week of plant operation. The following sampling plan is modeled after the procedures originally specified in NESHAP Subpart DDDDD of 40 CFR 63 (now vacated) for solid fuel-fired industrial boilers. The sampling plan identifies the following steps for sampling and analysis of the wood materials:

- Follow procedures to obtain five grab samples from the fuel pile for the representative composite sample;
- Prepare each composite sample according to the specified procedures; and
- Determine pollutant concentrations for each composite sample.

For each composite sample, identify a minimum of five sampling locations uniformly spaced over the surface of the pile. At each sampling location, take a sample at a depth of approximately 12 to 18 inches. Each grab sample will consist of approximately one gallon of wood chips or about 1.5 lb of wood chips. Each sample will be transferred to clean plastic bags. In general, the grab samples will be used to obtain the composite sample as described below:

- Throughout the sample collection, compositing and delivery to the laboratories, a chain of custody will be used to document sample collection through analysis.
- Thoroughly mix all of the individual grab samples and pour the entire composite sample over a clean plastic sheet.
- Break sample pieces larger than 3 inches into smaller sizes.
- Make a pie shape with the entire composite sample and subdivide into four equal parts.
- Separate one of the quarter samples as the first subset. If a duplicate sample is to be obtained for analysis,
SECTION 4. APPENDIX FM
Fuel Management Plan

separate a second quarter of the sample as the second subset.

- Do not grind the sample subset in a mill as this may contaminate the sample with metals.
- If the quarter sample is too large, subdivide it further as described above.
- Transfer each sample subset into a clean plastic sealable bag. Document and label each sample appropriately.
- At least one sample subset of the composite sample will be retained temporarily on site for use as a control sample to verify the lab results, if necessary.

The following methods (or equivalent) will be used to analyze as-fired composite wood samples:

- Heating Value reported in Btu/lb (modified ASTM D3286)
- Carbon Content reported in percent by weight, dry (modified ASTM D5373)
- Sulfur Content reported in percent by weight, dry (modified ASTM D4239 method C)
- Moisture Content reported in percent by weight (modified ASTM D3173)
- Copper, Chromium and Arsenic in ppm by weight, dry (Methods 3050/6010, EPA Method SW-846)

The composite samples will be processed by a third party vendor and/or laboratory for required analytical results. It is noted that the National Council for Air and Stream Improvement (NCASI) has identified grinding of biomass samples as a possible point of sample contamination due to the metals contained in the grinding equipment used in labs. As a result, the lab may not grind the sample, but instead may cut the samples to appropriate size prior to digestion and analysis.

**Correlation of Wood/Ash Analytical Results**

In conjunction with the analytical results of the mixed ash samples, results from the wood samples shall be used to evaluate the effectiveness of the fuel management program in removing chemically treated wood (e.g., copper, chromium and arsenic) from the biomass fuel. Results that indicate contamination of the wood fuel by copper, chromium, and/or arsenic in concentrations that exceed the specified limits in the air permit, will be investigated by the Environmental Coordinator, Shift Supervisor and/or Fuels Manager. Additional sampling, analysis and/or testing will be performed to determine the extent of the contaminated wood fuel.

**Records**

Records of the various wood material inspections and wood fuel and sampling and analysis procedures outlined in this Plan will be maintained at the plant for review on an as-requested basis by the Compliance Authority. The records will typically include: fuel delivery information (e.g., supplier, time/date of delivery, type of material, delivery size); written inspection reports of periodic unannounced site visits to wood fuel suppliers; and wood material and ash sampling and analysis information (e.g., time/date of sampling, locations selected for sampling, any atypical conditions, labs utilized, sample results). These records may also be used by plant personnel in investigating potential non-compliance events and verifying fuel test results.

**Palm Beach County Provisions**

The Zoning Plan approved by Palm Beach County requires that New Hope Power Company revise the fuel management plan to incorporate the “Inclement Weather Operating Procedures” and “Wood, Bagasse, and Ash Inspection and Testing Plan” as submitted to the Palm Beach County Health Department. New Hope Power Company must also request that the revised fuel management plan be included in the Title V operating permit (Petition DOA 1992-014B and Condition 11 of Resolution R-2004-1372). This Appendix FM of the Title V permit satisfies the County requirement.
Permit Conditions

1. **Wood Material - Sampling and Analysis**: At least twice each month, the permittee shall have an analysis conducted on a representative “as-fired” wood material sample for the following: heating value (modified ASTM D3286, Btu/lb, dry), carbon and ash content (modified ASTM D5373, percent by weight, dry), sulfur content (modified ASTM D4239 Method C, percent by weight, dry), moisture content (modified ASTM D3173, percent by weight); copper, chromium, and arsenic (ASTM Methods 3050/6010 or EPA Method SW-846, ppmw, dry). Samples shall be taken at least two weeks apart. Records of the results of these analyses shall be maintained on site and made available upon request. [Permit No. PSD-FL-196(P); Rule 62-4.070(3), F.A.C.]

2. **Wood Material - Prohibited Materials**: 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. [Permit No. PSD-FL-196(P)]

3. **Wood Material - Quarterly Report**: Within 30 days following each calendar quarter, the permittee shall submit to the Compliance Authority a summary of the following for the calendar quarter: analytical results for the “as-fired” wood material samples taken during the calendar quarter; analytical results that indicate exceedances of the allowable concentrations of copper, chromium, and arsenic; the ultimate disposal of any off-specification material; and a summary of any re-sampling/re-analysis of the wood material performed in the event an exceedance is indicated by the original analysis. [Permit No. PSD-FL-196(P); Rule 62-4.070(3), F.A.C.]

4. **Wood Material - Firing Records**: The permittee shall track the amount of wood chips delivered to the site and the amount of wood chips fired in the cogeneration boilers. The total annual heat input rate from firing wood chips shall be calculated based on the annual firing rate and the measured heating values as determined from the sampling and analyses conducted throughout the year. [Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.]

**DISTILLATE OIL AND NATURAL GAS**

**Description**

Distillate oil and natural gas are fired as startup/supplemental fuels in the cogeneration boilers and as the primary fuels for Boiler 16. Distillate oil shall be new No. 2 oil with a maximum sulfur content of 0.05% by weight. Each boiler may startup solely on natural gas or distillate oil. The firing of all fossil fuels (distillate oil and natural gas) shall be less than 25% of the total heat input to each cogeneration boiler during any calendar quarter.

The fuel oil system consists 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. The fuel oil will be stored in an enclosed tank surrounded by a berm, which is 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.

**Permit Conditions**

1. **Oil - Sampling and Analyses**:
   a. For each oil delivery, the permittee shall record and retain the date, the gallons delivered, heating value and a certified fuel oil analysis from the vendor identifying the sulfur content (percent by weight) and identification of the test method used.
   b. The following methods are approved analytical methods for determining these characteristics: ASTM Method D-129, ASTM D-1552, ASTM D-2622, and ASTM D-4294. Other more recent or equivalent
ASTM methods or Department-approved methods are also acceptable.

c. At least once during each federal fiscal year, the permittee shall have a representative sample taken from each oil storage tank and analyzed in accordance with the authorized methods. Results of the analyses shall be retained on site and made available for inspection upon a request from the Compliance Authority.

[Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.]

2. Oil - Firing Records: For the cogeneration units, the permittee shall observe the oil flow meter and record the amount oil fired for each calendar quarter within 10 days of the end of each quarter. The permittee shall also monitor and record the annual oil firing rate from the cogeneration units and Boiler 16 for use in filing the Annual Operating Report. The total annual heat input rate from oil firing shall be calculated based on the annual firing rate and the measured heating values as determined from the sampling and analyses conducted throughout the year. [Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.]

3. Natural Gas - Records: The permittee shall monitor and record the amount of natural gas combusted in each boiler on a quarterly basis within 10 days of the end of each month. [Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.]
General Procedures

Emissions of CO, PM/PM_{10}, and VOC shall be minimized by ensuring efficient combustion through the proper application of good combustion practices (GCPs). Operators will implement following measures to promote good combustion in each cogeneration boiler.

1. Maintain rotary pocket-style wood feeders with efficient air seal to minimize intrusion of ambient air.
2. Maintain effective water level controls in bottom ash system to prevent intrusion of ambient air.
3. Mix biomass fuel to provide a consistent fuel blend.
4. Maintain the flue gas oxygen content to provide efficient combustion for the existing conditions.
5. When necessary to enhance poor combustion, reduce the biomass fee rate below the maximum rate.
6. When necessary to enhance poor combustion, co-fire natural gas or distillate oil.

Specific Procedures

For each cogeneration boiler, operators will observe the following practices to provide reasonable assurance that GCPs are being employed. These actions may be performed by the operator or other personnel under the operations manager’s supervision. The information collected shall be reported to the operations manager.

1. Operators will maintain an optimal steam production rate by controlling the biomass fuel feed into the boiler.
2. Operators will provide sufficient combustion air to promote good combustion.
3. Operators will periodically view the boiler control instrumentation to confirm that good combustion is taking place. If abnormal combustion is observed, the operator will immediately take corrective action. The control room operator will log the occurrence and duration of all such events in the boiler operation log, along with the corrective action taken.
4. At least twice per shift, operators will examine the boiler grates for proper fuel distribution and make appropriate adjustments. Unusual observations will be logged.
5. At least once per shift, operators will perform a walk-around inspection of the boiler to check the following: fans, pumps, casing, ducting, control equipment, and monitoring equipment. Adjustments and repairs will be performed as necessary.
6. At least once per shift, operators will inspect the fuel feeders and clean as necessary.
7. Operators will use the installed oxygen meter for each unit to continuously monitor a representative sample of the flue gas. The oxygen monitor will be used with automatic feedback and/or manual controls to continuously optimize the air-to-fuel ratio parameters. Depending on the fuel quality and existing combustion conditions, the operator will provide sufficient excess air to ensure good combustion within the boiler. The instrument readouts are located in the boiler control room to provide real time data to the control room operator, and display the instantaneous and the historical average. The control room operators are instructed in the use of the O_{2} flue gas process monitor for combustion control. The control room operator will periodically observe the oxygen content and adjust boiler operations consistent with GCPs. The CO and NOx CEMS are set to alarm whenever:

   a. Measured NO_{X} emissions exceed the allowable emission rate (0.15 lb/MMBtu as a 30-day rolling average); and
   b. Measured CO emissions exceed the allowable CO emission rate (0.50 lb/MMBtu as a 30-day rolling average and 0.35 lb/MMBtu as a 12-month rolling average).

When an alarm is activated, the control room operator will take corrective action and adjust boiler operations consistent with GCPs. Corrective actions include, but are not limited to, adjusting the air-to-fuel
ratio, adjusting the ratio of under-fire air to over-fire air, or firing some fuel oil or natural gas in place of biomass. Corrective actions continue until the O₂, NOₓ, and/or CO flue gas concentrations are returned to acceptable levels.

**Use of Flue Gas Oxygen Monitor as BACT for Combustion Controls**

The permittee shall install, operate and maintain a flue gas oxygen monitor that meets the requirements of Performance Specification 3 in Appendix B of 40 CFR 60. Using the certified CO and NOₓ CEMS data, the permittee shall determine the influence of the flue gas oxygen content on CO and NOₓ emissions throughout the range of typical operating loads. As necessary, the permittee shall adjust the flue gas oxygen content in the boilers to control CO and NOₓ within the permitted emissions standards.
## ARMS ID. No. 0990005 – Okeelanta Corporation, Sugar Mill and Refinery

<table>
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<tr>
<th>EU ID No.</th>
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<td>0990005-005-AC</td>
<td>01/19/2001</td>
<td>01/19/2006</td>
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<tr>
<td>035</td>
<td>Transfer Bulk Load-Out Station</td>
<td>0990005-021-AC</td>
<td>01/15/2008</td>
<td>02/25/2008</td>
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<tr>
<td>043</td>
<td>Sugar Refinery Alcohol Usage</td>
<td>0990005-005-AC</td>
<td>01/19/2001</td>
<td>01/19/2006</td>
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<tr>
<td>046</td>
<td>Powdered Sugar Hopper</td>
<td>0990005-023-AC</td>
<td>01/16/2009</td>
<td>01/15/2010</td>
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<tr>
<td>047</td>
<td>Sugar Packaging Lines (11-14)</td>
<td>0990005-019-AC</td>
<td>04/11/2006</td>
<td>04/08/2008</td>
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## ARMS ID. No. 0990005 – Okeelanta Corporation, Sugar Mill and Refinery

<table>
<thead>
<tr>
<th>EU ID No.</th>
<th>Description</th>
<th>Permit Nos.</th>
<th>Issue Date</th>
<th>Exp. Date</th>
</tr>
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<tr>
<td>048</td>
<td>Paint Booth</td>
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<td>Initial Construction</td>
<td>0990005-010-AC</td>
<td>08/22/2001</td>
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<td>Modification</td>
<td>0990005-015-AC</td>
<td>11/02/2005</td>
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<td>049</td>
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<td>Initial Construction</td>
<td>0990005-023-AC</td>
<td>01/16/2009</td>
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<tr>
<td>054</td>
<td>Wet Roto-clone No. 6 – “A” System</td>
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<td>Initial Construction</td>
<td>0990005-027-AC</td>
<td>05/26/2011</td>
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<td>055</td>
<td>Wet Roto-clone No. 7 – “C” System</td>
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<td>Initial Construction</td>
<td>0990005-027-AC</td>
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<td>05/25/2012</td>
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<td>N/A</td>
<td>EXEMPT – Temporary Portable Jaw Crusher</td>
<td>0990005-028-AC</td>
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<td>N/A</td>
<td>EXEMPT – Packaging Line 10 Baghouse</td>
<td>0990005-029-AC</td>
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<td>N/A</td>
<td>EXEMPT – Pkg. Line 10 baghouse Administrative Correction</td>
<td>0990005-030-AC</td>
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<td>0990005-031-AC</td>
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### ARMS ID. No. 0990332 – New Hope Power’s Okeelanta Cogeneration Plant

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<tr>
<th>EU ID No.</th>
<th>Description</th>
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<tr>
<td>001</td>
<td>Cogeneration Boiler No. A</td>
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<tr>
<td>002</td>
<td>Cogeneration Boiler No. B</td>
</tr>
<tr>
<td>003</td>
<td>Cogeneration Boiler No. C</td>
</tr>
<tr>
<td>004</td>
<td>Cogeneration Plant - Material Handling and Storage</td>
</tr>
<tr>
<td>005</td>
<td>Cogeneration Plant – Miscellaneous Support Equipment</td>
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</tbody>
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<table>
<thead>
<tr>
<th>Description</th>
<th>Permit Nos.</th>
<th>Issue Date</th>
<th>Exp. Date.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial air construction permit (AC50-219413)</td>
<td>AC50-219413 (PSD-FL-196)</td>
<td>09/27/1993</td>
<td>07/01/1996</td>
</tr>
<tr>
<td>Extension of initial air construction permit</td>
<td>AC50-219413 (PSD-FL-196)</td>
<td>---</td>
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<tr>
<td>Modified to add limit of 30% yard trash (NSPS Subpart Ea)</td>
<td>0990332-001-AC (PSD-FL-196A)</td>
<td>02/20/1996</td>
<td>04/01/1997</td>
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<tr>
<td>1st Extension for simultaneous operation with mill boilers</td>
<td>0990332-002-AC (PSD-FL-196B)</td>
<td>06/14/1996</td>
<td>04/01/1997</td>
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<tr>
<td>Temporary permit to conduct trial burn of TDF (expired)</td>
<td>0990332-003-AC (PSD-FL-196C)</td>
<td>01/22/1997</td>
<td>12/31/1998</td>
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<tr>
<td>2nd Extension for simultaneous operation with mill boilers</td>
<td>0990332-005-AC (PSD-FL-196E)</td>
<td>04/05/1997</td>
<td>04/01/1998</td>
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<tr>
<td>Modified of CO, Pb, and Hg standards</td>
<td>0990332-006-AC (PSD-FL-196F)</td>
<td>10/24/1997</td>
<td>07/01/1998</td>
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<tr>
<td>Modified performance test schedule (Specific Condition #11)</td>
<td>0990332-007-AC (PSD-FL-196G)</td>
<td>05/08/1997</td>
<td>04/01/1998</td>
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<td>Withdrawn</td>
<td>0990332-008-AC (PSD-FL-196H)</td>
<td>09/15/1997</td>
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<td>3rd Extension for simultaneous operation with mill boilers</td>
<td>0990332-009-AC (PSD-FL-196I)</td>
<td>06/15/1998</td>
<td>04/01/2001</td>
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<tr>
<td>Modified CO standard</td>
<td>0990332-010-AC (PSD-FL-196J)</td>
<td>06/24/1999</td>
<td>04/01/2001</td>
</tr>
<tr>
<td>Modified to add mechanical dust collectors before ESP</td>
<td>0990332-012-AC (PSD-FL-196K)</td>
<td>12/22/1999</td>
<td>10/01/2002</td>
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<tr>
<td>Modified to add natural gas as startup/supplemental fuel</td>
<td>0990332-013-AC (PSD-FL-196L)</td>
<td>01/24/2001</td>
<td>10/01/2002</td>
</tr>
<tr>
<td>Modified CO, Fl, Pb, Hg, SO₂, and SAM standards</td>
<td>0990332-014-AC (PSD-FL-196M)</td>
<td>01/31/2002</td>
<td>10/01/2002</td>
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<tr>
<td>Modified electrical generation basis from “gross” to “net”</td>
<td>0990332-015-AC (PSD-FL-196N)</td>
<td>05/01/2001</td>
<td>10/01/2002</td>
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<tr>
<td>Modified maximum heat input rate to 760 MMBtu per hour</td>
<td>0990332-016-AC (PSD-FL-196O)</td>
<td>10/27/2003</td>
<td>09/01/2004</td>
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<tr>
<td>Modified to add 65 MW steam turbine electrical generator</td>
<td>0990332-017-AC (PSD-FL-196P)</td>
<td>06/06/2005</td>
<td>12/15/2006</td>
</tr>
</tbody>
</table>
NEW HOPE POWER COMPANY (Facility ID No. 0990332)

Permit No. PSD-FL-196 (as modified) requires the permittee to develop and maintain operation and maintenance plans (O&M) for the cogeneration boilers and pollution control equipment. To the extent practicable, plant personnel will follow the procedures identified in this O&M plan to ensure good operation and control of emissions. Operation outside of the specified 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.

Cogeneration Boilers A, B and C (EUs 001, 002 and 003)

General Description: The cogeneration boilers combust biomass (bagasse and wood) to generate steam and electricity. Distillate oil and natural gas are fired as startup and supplemental fuels. The cogeneration facility supplies the adjacent Okeelanta sugar mill with process steam during the sugarcane grinding season (approximately October through March) and also supplies the associated Okeelanta sugar refinery with process steam year around.

Key Design and Operating Parameters: The key design and operating parameters for the cogeneration boilers are the power generation rate, steam rate, heat input rate, and combustion efficiency. The design rates for these are provided below. The DCS (Distributed Control System) is a computer operated system that continuously monitors the operation of key parameters for the boilers, mechanical collectors, ESPs and SNCR system on each boiler. In addition, this system monitors the CEMs, which measure the boiler flue gas for oxygen and the stack flue gas for SO\textsubscript{2}, NO\textsubscript{X} and CO. The system will trigger an alarm if any operating conditions are outside of recommended or regulatory ranges.

Capacity: Each cogeneration boiler has a maximum heat input rate of 760 MMBtu/hr when combusting biomass, 605 MMBtu/hr when combusting natural gas, and 490 MMBtu/hr when combusting distillate oil. Each cogeneration boiler has a maximum steam production rate of 506,100 lb/hr at 1500 psig and 975°F. The thermal combustion efficiencies are 68% for biomass and 85% for natural gas and distillate oil. The three cogeneration boilers supply steam to one nominal 75 MW (net) steam-electrical generator and one nominal 65 MW (net) steam-electrical generator.

Good Operating Practices: See Appendix GC of this permit for good combustion practices.

Startup and Shutdown: See Section 3A of this permit for the startup and shutdown plan.

Air Pollution Controls: Particulate emissions are controlled from each boiler by mechanical collectors followed by an electrostatic precipitator. Nitrogen oxide emissions are controlled by the injection of urea in a selective non-catalytic reduction system. Mercury emissions are controlled, as needed, through a carbon injection system and the ESP. These controls are described below in more detail.

Pollutant Emission Rates: The potential annual controlled annual emission rates in tons per year (TPY) for all three cogeneration boilers combined are as follows: 3495 tons/year of CO; 108 pounds per year of Hg; 1498 tons/year of NO\textsubscript{X}; 260 tons/year of PM; 260 tons/year of PM\textsubscript{10}; 37 tons/year of SAM; 599 tons/year of SO\textsubscript{2}; and 499 tons/year of vOC.

Mechanical Dust Collectors

General Description: The cyclone dust collectors were supplied by Barron Industries, Model 460 Tube Base III 9K15-2023AU. These are mechanical dust collectors which remove larger PM prior to the ESP. There are 460 cyclone tubes in all.

Capacity: The mechanical dust collectors are designed for a flow rate of 359,506 acfm and an exhaust temperature of 450°F.

Design Efficiency: The mechanical dust collectors are designed for a control efficiency of 85% of the particulate matter greater than 10 microns in size (assuming a specific gravity of 2.00).
Key Design and Operating Parameters and Good Operating Practices: The following parameters are monitored by the DCS for the mechanical dust collectors:

- Operation of ash hopper screw conveyors to monitor if any plugging has occurred.
- Amperage on elevating screw conveyor: if amperage is high, plugging may have occurred and is therefore checked.

In addition, during each outage of the boilers, the dust collector tubes are inspected for damage and wear. Tubes are replaced as necessary.

Electrostatic Precipitators (ESPs)

General Description: Each boiler is equipped with a single ESP for particulate control. Each ESP consists of one chamber with three fields in the direction of flow. Each field has one bus section for a total of three bus sections per chamber. Each bus section is electrically energized by one transformer/rectifier set mounted at the roof level.

Key Design and Operating Parameters: Each ESP is manufactured by Flakt, Inc. with the following design specifications:

- Chambers = 1
- Collecting Plate = 12.30 ft L x 39.37 ft H
- Fields/Chamber = 3
- Specific Collection Area = 200 ft²/1,000 acfm (minimum)
- Gas Velocity = < 4 ft/s
- Pressure Drop = less than 2.8 inches H₂O
- Operating Temperature = 350° F
- Ash Handling = Trough hopper with screw conveyor
- Design Control Efficiency: 98% or greater for particulate matter.

O&M Practices: The ESP is designed as a static piece of equipment employing a minimum of moving parts. The preventative maintenance plan for the ESP includes the following:

Daily

- Each shift, an inspection of the ESP is conducted to check for any unusual conditions that may exist. An operations log sheet is used by plant personnel to record shift operational activities. The log sheet is reviewed daily by the plant operations manager. The following operational parameters are inspected each shift and any unusual conditions are logged:
  - All electrical readings of the ESP and related equipment. In addition, any unusual conditions such as circuit breaker trip are recorded and investigated immediately.
  - Process operating conditions, including firing rates, steam production (lb/hr), flue gas temperature, and flue gas composition. Any unusual operating conditions are investigated and corrected immediately.
  - Gear motors and transformer/rectifiers are checked for oil leaks. Oil leaks are repaired immediately and oil levels are adjusted as necessary.
  - Any unusual or excessive noises coming from motors, or control equipment. Any unusual conditions are corrected immediately.
  - Inspection of doors / stuffing boxes to detect gas and air leaks.
  - In addition, as described above, continuous emission monitor (CEM) data is recorded continuously and is
monitored by plant operators. All CEM data for all pollutants (NOx, SO2, CO, and opacity) are stored via electronic files. The ESP operating temperature and transformer/rectifier primary current and voltages are also monitored and recorded continuously. If unusual data is recorded, the source of the problem is investigated and corrected immediately.

- In addition to the daily shift log completed above, the following additional inspections are made, and repairs performed as necessary, on a monthly, quarterly, semi-annual and annual schedule:

**Monthly:** Clean and inspect the ESP cold roof.

**Quarterly**

- Stuffing boxes for rapper drives and dampers are adjusted for leaks and replaced if necessary.
- Rapping drive mechanisms are inspected for excessive noise and wear. If out-of-spec operating conditions exist the mechanisms are repaired or replaced.
- Visually check transformer/rectifier for oil level in tank. Oil is added if necessary.

**Semiannually:** Rapping drive gearmotor oil is sampled and changed, if contaminated.

**Annually/During Shut Down**

- All ESP internals are inspected.
- Insulators are cleaned and checked for dust, cracks, or evidence of current leakage.
- Transformers/Rectifiers are checked for proper liquid level, dielectric strengths and for formation of deposits.
- If any equipment is not operating within specifications the component will be replaced or repaired.
- During annual ESP shutdown, a thorough inspection of all ESP components is performed. The checklist includes the following ESP equipment:

<table>
<thead>
<tr>
<th>Transformers/Rectifier (T/R) Set</th>
<th>Gas Distribution Plates</th>
<th>Discharge Electrodes</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Ground Connections</td>
<td>b. Corrosion</td>
<td>c. Electrodes</td>
</tr>
<tr>
<td>c. High Tension Bus Duct</td>
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<td>d. Alignment</td>
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<tr>
<td>d. Conduits</td>
<td></td>
<td>e. Corrosion</td>
</tr>
<tr>
<td>e. Alarm Connections</td>
<td></td>
<td>f. Build-up</td>
</tr>
<tr>
<td>f. Ground Switch Operation</td>
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<td></td>
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<tr>
<td>g. High Voltage Connections</td>
<td></td>
<td></td>
</tr>
<tr>
<td>h. Surge Arrestors</td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. Wire Terminations</td>
<td>a. Build-up</td>
<td>a. Supports</td>
</tr>
<tr>
<td>b. Ground Connections</td>
<td>b. Corrosion</td>
<td>b. Alignment</td>
</tr>
<tr>
<td>c. Circuit Breakers Trip</td>
<td>c. Leaks</td>
<td>c. Corrosion</td>
</tr>
<tr>
<td>d. Mechanism</td>
<td>d. Access Doors</td>
<td>d. Buildup</td>
</tr>
<tr>
<td>e. Meter Terminations</td>
<td></td>
<td></td>
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<tr>
<td>f. Air Filters, For Cleanliness</td>
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<tr>
<td>g. Fans</td>
<td></td>
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<tr>
<td>b. Locked Cabinets</td>
<td>b. Bearings</td>
<td>b. Properly Located</td>
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<tr>
<td>c. Meters Recorded</td>
<td>c. Clearance to Supports</td>
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<td>12. Discharge Electrodes</td>
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<tr>
<td>12. Gas Distribution Plates</td>
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<tr>
<td>12. Transformer/Rectifier (T/R)</td>
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<td>7. Through Hopper</td>
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<tr>
<td>a. Build-up</td>
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<td>b. Corrosion</td>
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<td>c. Leaks</td>
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<td>d. Access Doors</td>
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<td>13. Collecting Electrodes</td>
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<tr>
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<tr>
<td>b. Alignment</td>
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<tr>
<td>c. Corrosion</td>
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<td>d. Buildup</td>
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<td>14. Gas Sneakage Baffles</td>
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<td>b. Properly Located</td>
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<td>15. Screw Conveyors</td>
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<tr>
<td>a. Lubrication</td>
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<td>b. Gear Box Lubrication</td>
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<td>c. Condition of Screw</td>
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<td>d. Pluggage (Inlet &amp; Outlet)</td>
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<tr>
<td>e. Belt Tension</td>
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</table>
Any equipment or component that is not operating properly or is excessively worn is replaced or repaired prior to ESP operation.

**Selective Non-Catalytic Reductions (SNCR) System**

**General Description:** A urea injection system manufactured by Nalco-FuelTech is installed for NO\textsubscript{X} control. The technology is a selective non-catalytic reduction (SNCR) process, which reduces NO\textsubscript{X} emissions through chemical reactions with urea. In this process, urea is injected into the flue gas stream and reacts with NO\textsubscript{X} to form nitrogen and water vapor. The NO\textsubscript{X} control system includes the following major components: carrier air compressors, urea tank, urea/air flow controls, control panel, injection manifolds, injectors, valves and instrumentation. A single urea storage tank system supplies urea to the boilers. Two injection zones are used to provide injection at full and part load conditions. The first zone has six injectors and the second zone has six injectors, for a total of twelve injectors per boiler. Zone switching valves direct the urea/carrier mixture to the appropriate injection zone.

**Key Design and Operating Parameters:** The urea injection system is designed to meet a maximum NO\textsubscript{X} emission rate of 0.15 lb/MMBtu when firing biomass or No. 2 fuel oil. At maximum capacity, the Urea injection rate is approximately 65 GPH and the ammonia slip may be as high as 25 ppmvd. The NO\textsubscript{X} design removal efficiency is 40%.

**O&M Practices:**

Each shift, the plant operator completes an inspection of the urea injection system. The inspection includes the urea pressure, urea flow and air pressure for each injector. Once per shift, the air and chemical valves are closed simultaneously to check each injector for fouling. Pressures and flows are adjusted as necessary. At a minimum of once per week the injector nozzles are inspected and cleaned. Any unusual conditions are repaired and noted.

The urea metering module and urea circulation modules are also inspected once per shift. The operating conditions recorded on the metering module for each boiler include dilution water pressure, NO\textsubscript{X} pump in service, NO\textsubscript{X} gallons per minute, water pump flow, and water pump discharge pressure. The urea circulation module parameters recorded on a shift basis include the urea tank level, circulation pump condition, and the strainer differential pressure. If any of the parameters listed above are not operating within the normal range, repairs are initiated and recorded in the logbook. The logbook is reviewed daily by the plant operations and maintenance manager.

**Injectors**

- The distribution module flows and pressures are inspected at least once per shift.
- The injectors are pulled from the boiler and cleaned of built up scale on a weekly schedule.
- During injector cleaning the chamber cap and atomization chamber are removed and the orifices inspected and cleaned to assure that partial plugging has not occurred.
**Mechanical Components:** Bi-annually a general inspection of mechanical components is performed to check for evidence of corrosion, loosening or shifting parts due to vibration or wear, or any evidence of overheating. Any component showing evidence of damage, breakage, or wear is replaced.

**Circulation and Water Boost Pumps:** Visual inspections are performed on a daily basis looking for early signs of wear and/or failure of pump and seal components. If a defective part is discovered, the mechanical component is replaced.

**Metering Pumps:**
- Visual inspections are performed on a daily basis looking for early signs of wear and/or failure of the metering pump and seal components. If a defective part is discovered, the mechanical component is replaced.
- The drive housing oil is changed when contaminated.
- The metering pump DC motor and DC drive are checked monthly.

**Valves:** On at least a weekly basis each valve is exercised fully open and closed and checked for proper operability and leak tightness. Packing, seals, ball valves and other valve components are replaced if signs of wear are found.

**Regulators:** Upon discovery of erratic regulator operations the regulators are cleaned. Erratic regulator operations are usually caused by dirt accumulation in the disk area.

**Strainers:** Strainer baskets on the circulation module and metering module are replaced when wear becomes evident. The baskets are cleaned when the pressure differential across the strainer is greater than five (5) psig.

**Pressure and Temperature Indicators:** On each shift, the pressure indicator is inspected for soundness and validity. If the instrument is suspect, the equipment is either recalibrated or replaced as necessary. Each instrument is calibrated a regular basis. The pressure indicators have a root valve that can be closed to isolate the pressure indicator from the system. The indicator can then be removed for calibration without shutting the system down.

**Flow Meters:** On each shift, the flow meter is checked for soundness and validity. If the instrument calibration is suspect, the flow indicators are re-calibrated or replaced. Periodically, the electrical and mechanical fitting are inspected for looseness or separation. If an out-of-spec condition exists the problem is corrected or the component is replaced.

**Metering Module Control Panels:** The panel is maintained free of dirt and cleaned periodically. Occasional blowing out with dry air is performed on the panels. All control panel devices (i.e., timer, relay, contactor, lamp or other device) are inspected and if found to be defective are replaced.

**Alternate NOx Emissions Control Plan**

This alternate NOx control plan identifies the minimum urea injection rate that has demonstrated continuous compliance with the NOx emissions limit at various load conditions. The purpose of this plan is to monitor compliance with the NOx standards when the CEM for NOx is not operating. If a CEM for NOx is out of service, New Hope Power Company will continue to inject urea at a rate consistent with the other operating boilers. This rate is generally in the range of 50 to 75 gal/hr of urea per boiler. If a monitor goes out of service, and no other boiler is operating, New Hope Power Company will continue to inject urea into the boiler at the injection rate that existed just prior to the monitor outage. It is noted that historically, the NOx monitors at New Hope Power Company have had downtimes of less than 1 percent. As a result, the alternative NOx monitoring plan will likely be utilized very infrequently in the future.

**Activated Carbon Injection – Mercury Control System**

**General Description:** The mercury control system consists of a volumetric feeder with an integral supply hopper that meters activated carbon for flue gas injection. The injection point is located between the boiler and...
the ESP. A blower system transports the carbon to the injection point. The ESP effectively captures the activated carbon particles along with boiler flyash (which contains some carbon). The system is designed to inject up to 13 lb/hr of activated carbon into the flue gases of each boiler. The activated carbon is manufactured specifically for removal of heavy metals and mercury contaminants found in exhaust gases. It is also effective for adsorption of dioxins and other incomplete combustion byproducts. The activated carbon is a free flowing powdered carbon with minimal caking tendencies, which makes it ideal for automatic carbon injection systems. It is manufactured with a high ignition temperature to permit safe operations at elevated temperatures. The unique convoluted particle surface provides the maximum reaction surface for rapid removal of gaseous mercury vapors.  

(Permitting Note: At the issuance of this permit, the activated carbon system was inactive and the cogeneration units demonstrated compliance with the mercury standard without injecting activated carbon.)

Key Design and Operating Parameters:  The system is designed to inject up to 13 lb per hour of activated carbon into the flue gases of each boiler. Due to the very low mercury emissions from the New Hope Power Company boilers, and the presence of unburned carbon in the flue gas of the boilers, it is not possible to establish a design removal efficiency for the mercury injection system. The carbon feed system consists of the following equipment: storage silo/hopper, feeder motor, feeder gear reducers, feeder vibrator, knifegate valves, educators, solenoid valves, pressure gages, an air line regulator and a strainer/filter. Listed below are operation and maintenance procedures for safe and effective operation of the mercury control system.

O&M Procedures

Normal Activated Carbon Filling Operations

- The hopper is visually inspected for leaks of activated carbon. If leakage occurs, a silicone sealant or stiff epoxy is applied to the area.
- The inside of the hoppers are inspected and any foreign matter present is removed.
- The flexible connector is replaced and the bands are inspected. The knifegate valves above the screw feeders are closed.
- The pressure-vacuum relief valve is closed, and all coupling bolts on the pneumatic valves are inspected for tightness.
- The main panel disconnect is placed in the on position.
- The main control panel hopper low, intermediate, and high level light illumination is inspected.
- The fill line cap from any of the fill lines is removed to energize the dust collector blower. The blower should be running when loading carbon.
- The transfer pressure from truck loading is monitored and should not exceed 10 psig. If excessive pressure is required to load the hoppers the target boxes and fill lines are checked for an unacceptable accumulation of carbon and cleaned as required.

Blower Checks, Line Pressure, and Flow

- During each shift, the operator checks that the feeder/blower is in service and checks the % feed rate of activated carbon. If the equipment or % feed rate is out of specification, repairs and adjustments are made immediately. In addition, all blower discharge pressure gauges should read approximately 14 psig. If the pressure is less than 14 psig the blower shaft is adjusted and checked against the nameplate speed. More pressure is acceptable; the blower is protected by an inline relief valve. The relief valve is set to 15 psig.
- The flow of air at each line’s termination point is checked. Velocities should be approximately 3000 feet per minute and pressures close to atmospheric. If a low velocity is detected, all elements of the line are checked for debris and water.
**Feeder Calibration:** The CHEMCO screw driver is designed to deliver a minimum of 1.5 pounds of carbon per hour and a maximum of 13 pounds. Periodically, samples of carbon from the feeder discharge spout are collected in order to calibrate the feeder. If necessary, the feeder is recalibrated and/or the malfunctioning equipment is replaced.

**Hopper Fluidizing System Checks**

- The fluidizing timers within the main control panel are set to a frequency range of 5 to 15 minutes depending on the rate of carbon fed. The higher the feed rate the more frequent the solenoids must be energized to pulse the hopper cones with air.
- The bypass valve must be cracked open and pressurized anytime carbon is in the hoppers.
- Carbon Educators.
- The capability of the educator to ingest solids is dependent upon the position of the nozzle relative to the throat of the educator. The nozzle tip should be pushed in so that it is near the center of the educator suction opening.
- Air admitted to the educator on the screw feed end (suction air) can be controlled using the valves located on the mixing funnel. There are no means provided for measuring the amount of air required for a given feed rate; however, there are two valves provided on the top of each funnel for the purposes of adjusting the suction air flow. The valves may need to be adjusted under certain plant specific operating conditions and both valves should be adjusted to the same setting to prevent an unsymmetrical air-flow into the funnel.

**Reactivation Plan:** If two or more cogeneration boilers exceed the annual mercury emission limit, the carbon injection system will be activated for all three boilers within 30 days of the stack test report due date.
### Facility Name
Okeelanta Cogeneration Plant

### ARMS ID No.
0990332

### Title V Air Permit No.

<table>
<thead>
<tr>
<th>Facility Address/Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Located off U.S. Highway 27 South, approximately six miles south of South Bay in Palm Beach County, Florida</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Emissions Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Spreader stoker boiler with maximum heat input of 760 MMBtu/hour</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Unit Operation in Calendar Quarter</th>
</tr>
</thead>
<tbody>
<tr>
<td>________ hours</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Control Equipment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mercury - activated carbon injection; Nitrogen Oxides – low NOx burners and selective non-catalytic reduction (NOx) system; Particulate Matter – mechanical dust collectors and electrostatic precipitators</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Primary Fuel</th>
</tr>
</thead>
<tbody>
<tr>
<td>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)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Auxiliary Fuels</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipeline natural gas</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pollutant Monitored (Check one.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Continuous Monitor Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manufacturer: ____________________</td>
</tr>
<tr>
<td>Model No. ________________________</td>
</tr>
<tr>
<td>Date of last certification or audit: ____________________</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Calendar Quarter of Operation Covered (Check one.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Emission Standards</th>
</tr>
</thead>
<tbody>
<tr>
<td>_____ lb/MMBtu of heat input, 24-hour rolling avg.</td>
</tr>
<tr>
<td>_____ lb/MMBtu of heat input, 30-day rolling avg.</td>
</tr>
<tr>
<td>_____ lb/MMBtu of heat input, 12-month rolling avg.</td>
</tr>
<tr>
<td>_____ % opacity, except for one 6-minute block per hour ≤ _____ % opacity</td>
</tr>
</tbody>
</table>

### 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. \[ \text{[Total duration of excess emissions]} \times (100\%) \]

### 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. \[ \text{[Total CMS Downtime]} \times (100\%) \]

### 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.
PERMIT SUBSECTION 3A - COGENERATION BOILERS

Facility ID No. 0990332 – New Hope Power’s Okeelanta Cogeneration Plant

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>001</td>
<td>Cogeneration Boiler A</td>
</tr>
<tr>
<td>002</td>
<td>Cogeneration Boiler B</td>
</tr>
<tr>
<td>003</td>
<td>Cogeneration Boiler C</td>
</tr>
<tr>
<td>004</td>
<td>Cogeneration Plant – Material Handling and Storage</td>
</tr>
</tbody>
</table>

**Generating Capacity:** Two steam turbine electrical generators (75 MW and 65 MW)

**Maximum Heat Input Rate:** 760 MMBtu/hour (biomass), 605 MMBtu/hour (gas), and 490 MMBtu/hour (oil)

**Maximum Steam Rate:** 506,100 pounds per hour at 1500 psig and 975°F

**Primary Fuels:** Bagasse and wood waste (clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter)

**Startup and Auxiliary Fuels:** Natural gas and distillate oil (≤ 0.05% sulfur by weight)

**NOx Controls:** Low-NOx natural gas burners and a selective non-catalytic reduction (SNCR) system

**Particulate Matter Controls:** Mechanical dust collectors and an electrostatic precipitator (ESP)

**Mercury Controls:** Activated carbon injection system (originally installed for firing coal) – *(Currently inactive)*

**Process Monitors:** Maintain continuous monitors for fuel feed rate, heat input, steam production, steam pressure, steam temperature, net power generation, urea injection rate, and activated carbon injection rate (as needed).

**CEMS:** Maintain continuous emissions monitoring systems (CEMS) to measure and record emissions of carbon monoxide (CO), nitrogen oxides (NOx), opacity, carbon dioxide (CO₂) in lieu of oxygen, and sulfur dioxide (SO₂).

**COMS:** Maintain continuous opacity monitoring systems (COMS) to measure and record stack opacity.

**Restrictions:** Operating hours are not restricted. 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. Combust no wood material containing more than 70.7 ppm arsenic or 83.3 ppm chromium or 62.8 ppm copper. Fossil fuel firing (distillate oil and natural gas) shall be less than 25% of the total heat input to each cogeneration boiler during any calendar quarter.

**Emissions Standards Summary:**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Compliance Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>0.50 lb/MMBtu, 30-day rolling avg.</td>
<td>CEMS</td>
</tr>
<tr>
<td></td>
<td>0.35 lb/MMBtu, 12-month rolling avg.</td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>0.15 lb/MMBtu, 30-day rolling avg.</td>
<td>CEMS</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.20 lb/MMBtu, 24-hour rolling avg.</td>
<td>CEMS</td>
</tr>
<tr>
<td></td>
<td>0.10 lb/MMBtu, 30-day rolling avg.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>0.06 lb/MMBtu, 12-month rolling avg.</td>
<td></td>
</tr>
<tr>
<td>Opacity</td>
<td>≤ 20%, except for one 6-minute block per hour that is ≤ 27%</td>
<td>COMS and EPA Method 9</td>
</tr>
</tbody>
</table>
### Summary of Standards

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Compliance Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM/PM$_{10}$</td>
<td>0.026 lb/MMBtu, 3-run test avg.</td>
<td>EPA Method 5 Stack Test</td>
</tr>
<tr>
<td>VOC</td>
<td>0.05 lb/MMBtu, 3-run test avg.</td>
<td>EPA Method 25A Stack Test</td>
</tr>
<tr>
<td>Mercury</td>
<td>$5.4 \times 10^{-6}$ lb/MMBtu, 3-run test avg.</td>
<td>EPA Method 101A or 29 or 30B</td>
</tr>
</tbody>
</table>

**Test Notification:** Provide 15 day advance notice of each test.

**Test Reports:** Submit test report within 45 days after conducting a test.

**Annual Tests:** Conduct annual stack tests for mercury, PM/PM$_{10}$, and VOC.

**Fuel Records:** Maintain a daily log of the amounts and types of fuels used. For each fuel oil delivery, maintain the amount, heating value, and sulfur content. For each calendar month, record the actual monthly SO$_2$ emissions and the 12-month rolling total SO$_2$ emissions.

**Quarterly Reports:** Within 30 days following each calendar quarter, submit to the Compliance Authority a report summarizing operation of each required continuous emissions and opacity monitoring system in accordance with the requirements specified in the “Quarterly Report” included in Appendix QR of this permit. Report shall also include a 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.


**CAM:** PM/PM$_{10}$ emissions controlled by multi-cyclones and ESP

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**PERMIT SUBSECTION 3B - MATERIAL HANDLING & STORAGE OPERATIONS, COGENERATION PLANT**

**Facility ID No. 0990332 - New Hope Power’s Okeelanta Cogeneration Plant**

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>004</td>
<td>Material Handling and Storage Operations includes unloading operations, stockpiles, transfer operations, conveyors, screens, crushers, hoppers and silos. Hours of operation are not restricted.</td>
</tr>
</tbody>
</table>

**Fly Ash Silo and Activated Carbon Silo:**

**Controls:** Baghouses $\leq 0.01$ grains per acfm (design specification for new and replacement bags).

**Opacity Standard:** Visible emissions $\leq 5\%$ opacity based on a 6-minute average.

**Compliance Tests:** Conduct EPA Method 9 for opacity annually for each silo that is loaded with ash or carbon.

**Test Notification:** Provide 15 day advance notice of each test.

**Test Reports:** Submit test report within 45 days after conducting a test.

**CAM:** No

**Fugitive Dust:**

**Controls:** As necessary, take reasonable precautions to prevent fugitive dust.
PERMIT SUBSECTION 3C - SUGAR MILL & REFINERY

Facility ID No. 0990005 – Okeelanta Corporation Sugar Mill and Refinery

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>EU-014</td>
<td>Boiler 16 – DELETED (Permit No. 0990005-032-AV)</td>
</tr>
</tbody>
</table>

PERMIT SUBSECTION 3D - SUGAR REFINERY

Facility ID No. 0990005 – Okeelanta Corporation Sugar Mill and Refinery

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>021</td>
<td>Wet Roto-clone No. 1 (Rotary Dryer)</td>
</tr>
<tr>
<td>022</td>
<td>Wet Roto-clone No. 2 – “B” System</td>
</tr>
<tr>
<td>023</td>
<td>Cooler No. 1 with Roto-clone No. 3</td>
</tr>
<tr>
<td>024</td>
<td>Cooler No. 2 with Roto-clone No. 4</td>
</tr>
<tr>
<td>025</td>
<td>Fluidized Bed Dryer/Cooler with Baghouse</td>
</tr>
<tr>
<td>034</td>
<td>Bulk Load-Out Operation</td>
</tr>
<tr>
<td>035</td>
<td>Transfer Bulk Load-out Station</td>
</tr>
<tr>
<td>043</td>
<td>Sugar Refinery Alcohol Usage</td>
</tr>
<tr>
<td>054</td>
<td>Wet Roto-clone No. 6 – “A” System (Permit No. 0990005-027-AC)</td>
</tr>
<tr>
<td>055</td>
<td>Wet Roto-clone No. 7 – “C” System (Permit No. 0990005-027-AC)</td>
</tr>
</tbody>
</table>

Permitted Capacities: Hours of operation are not restricted. Refined sugar production shall not exceed 490,000 tons/consecutive 52 weeks. Sugar refinery equipment is limited as follows:

- Fluidized Bed Dryer (EU-025) ≤ 490,000 tons of refined sugar/consecutive 52 weeks.
- Rotary Dryer/Cooler System ≤ 130,000 tons of refined sugar/consecutive 52 weeks.
- Bulk Load-Out Operation (EU-034) ≤ 139,000 tons of refined sugar/consecutive 52 weeks.
- Transfer Bulk Load-Out Station (EU-035) ≤ 351,000 tons of refined sugar/consecutive 52 weeks.
- Sugar refinery alcohol usage (EU-043) ≤ 78,040 pounds/consecutive 52 weeks.

Particulate Matter (PM) Emission Standard: The sum of emissions from all emission units shall NOT exceed 22.15 TPY of PM2.5 and 3.00 TPY of PM10.

Opacity Standard: ≤ 5% opacity from each controlled exhaust point (EU-021, 022, 023, 024, 025).

Compliance Tests: Conduct EPA Method 9 for opacity each year for each controlled exhaust point.

Test Notification: Provide 15 day advance notice of each test.

Test Reports: Submit test report within 45 days after conducting a test.

Operational Records: Maintain records sufficient to demonstrate compliance with each permitted capacity.

CAM: No
PERMIT SUBSECTION 3E - TRANSSHIPMENT FACILITY

Facility ID No. 0990005 – Okeelanta Corporation Sugar Mill and Refinery

<table>
<thead>
<tr>
<th>ID</th>
<th>Emission Unit Description</th>
<th>ID</th>
<th>Emission Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>018</td>
<td>Central vacuum system No. 1</td>
<td>045</td>
<td>Powdered sugar dryer/cooler, packaging Line 8A and 8B</td>
</tr>
<tr>
<td>019</td>
<td>Sugar packaging Lines 0-9, including 8A and 8B</td>
<td>046</td>
<td>Powdered sugar hopper</td>
</tr>
<tr>
<td>020</td>
<td>Sugar grinder</td>
<td>047</td>
<td>Sugar packaging lines (12-14)</td>
</tr>
<tr>
<td>030</td>
<td>Sugar silos Nos. 1, 2, and 3 (Points #1101-1103)</td>
<td>049</td>
<td>Baghouse (Currently inactive).</td>
</tr>
<tr>
<td>031</td>
<td>Railcar sugar unloading receiver No. 1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>032</td>
<td>Railcar sugar unloading receiver No. 2</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Permitted Capacity: The maximum sugar packaging rate is 1300 tons/day. Hours of operation are not restricted.

Controls: All units are controlled by baghouses that must meet the following design specification for new and replacement bags:
- \( \leq 0.0005 \) grains per acfm for baghouse controlling EU-020
- \( \leq 0.01 \) grains per acfm for baghouses controlling EU-018, 019, 045, 046, and 047
- \( \leq 0.02 \) grains per acfm for baghouses controlling EU-030, 031, 032 and 049

Opacity Standard: Visible emissions \( \leq 5\% \) opacity from each baghouse exhaust point.


Test Notification: Provide 15 day advance notice of each test.

Test Reports: Submit test report within 45 days after conducting a test.

CAM: No

PERMIT SUBSECTION 3F - DISTILLATE OIL STORAGE TANKS

Facility ID No. 0990332 - New Hope Power’s Okeelanta Cogeneration Plant

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>005</td>
<td>Cogeneration Plant – Miscellaneous Support Equipment</td>
</tr>
</tbody>
</table>

Operational Records: Tanks shall store distillate oil. Maintain records of the types and amounts of fuel stored.

Facility ID No. 0990005 - Okeelanta Corporation’s Sugar Mill and Refinery

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>015</td>
<td><strong>DELETED</strong> - Distillate Oil Storage Tank (29,500 gallons)</td>
</tr>
<tr>
<td>016</td>
<td><strong>DELETED</strong> - Distillate Oil Storage Tank (29,500 gallons)</td>
</tr>
<tr>
<td>017</td>
<td><strong>DELETED</strong> - Distillate Oil Storage Tank (29,500 gallons)</td>
</tr>
</tbody>
</table>

Operational Records: Tanks shall store distillate oil. Maintain records of the types and amounts of fuel stored.
PERMIT SUBSECTION 3G - PAINT SPRAY BOOTH, FARM OPERATIONS

Facility ID No. 0990005 - Okeelanta Corporation’s Sugar Mill and Refinery

<table>
<thead>
<tr>
<th>EU No.</th>
<th>Emissions Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>048</td>
<td>Paint Booth</td>
</tr>
</tbody>
</table>

**Permitted Capacity:** The maximum throughput rate of paint, thinners and cleanup solvents shall not exceed 4950 gallons/consecutive 12-month period. Hours of operation are not restricted.

**Fugitive VOCs:** All equipment, pipes, hoses, lids, fittings, etc., shall be operated and maintained in such a manner as to minimize leaks, fugitive emissions, and spills of materials containing volatile organic compounds (VOC).

**VOC Emissions:** VOC ≤ 9.40 tons/consecutive 12-months

**Opacity Standard:** ≤ 20% opacity

**Operational Records:** Maintain monthly records of the following: actual hours of operation of the paint booth; dates of operation; amounts and types of coatings, thinners and cleanup solvents used; and a monthly calculation of VOC/HAP emissions. VOC/HAP emissions shall be calculated by assuming all VOC/HAP in the coatings, thinners and cleanup solvents evaporate. The mass fraction of VOC/HAP from each solvent-containing material shall be determined from the Material Safety Data Sheets (MSDS) supplied by the vendors. The permittee shall maintain a file of MSDS for each solvent-containing material that indicates the composition of the VOC/HAP. Solvent-containing materials include, but are not limited to, powder coatings, solvent coatings, thinners, and cleanup solvents. The file must be maintained on site and made available for inspection upon request. The permittee shall have until the last day of the following month to complete these records.
Operation

TV1. **General Prohibition.** A permitted installation may only be operated, maintained, constructed, expanded or modified in a manner that is consistent with the terms of the permit. [Rule 62-4.030, Florida Administrative Code (F.A.C.)]

TV2. **Validity.** 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. [Rule 62-4.160(2), F.A.C.]

TV3. **Proper Operation and Maintenance.** The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and 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. [Rule 62-4.160(6), F.A.C.]

TV4. **Not Federally Enforceable. Health, Safety and Welfare.** To ensure protection of public health, safety, and welfare, any construction, modification, or operation of an installation which may be a source of pollution, shall be in accordance with sound professional engineering practices pursuant to Chapter 471, F.S. [Rule 62-4.050(3), F.A.C.]

TV5. **Continued Operation.** An applicant making timely and complete application for permit, or for permit renewal, shall continue to operate the source under the authority and provisions of any existing valid permit or Florida Electrical Power Plant Siting Certification, and in accordance with applicable requirements of the Acid Rain Program, applicable requirements of the CAIR Program, and applicable requirements of the Hg Budget Trading Program, until the conclusion of proceedings associated with its permit application or until the new permit becomes effective, whichever is later, provided the applicant complies with all the provisions of subparagraphs 62-213.420(1)(b)3., F.A.C. [Rules 62-213.420(1)(b)2., F.A.C.]

TV6. **Changes without Permit Revision.** Title V sources having a valid permit issued pursuant to Chapter 62-213, F.A.C., may make the following changes without permit revision, provided that sources shall maintain source logs or records to verify periods of operation:
   a. Permitted sources may change among those alternative methods of operation;
   b. A permitted source may implement operating changes, as defined in Rule 62-210.200, F.A.C., after the source submits any forms required by any applicable requirement and provides the Department and EPA with at least 7 days written notice prior to implementation. The source and the Department shall attach each notice to the relevant permit;
      (1) The written notice shall include the date on which the change will occur, and a description of the change within the permitted source, the pollutants emitted and any change in emissions, and any term or condition becoming applicable or no longer applicable as a result of the change;
      (2) The permit shield described in Rule 62-213.460, F.A.C., shall not apply to such changes;
   c. Permitted sources may implement changes involving modes of operation only in accordance with Rule 62-213.415, F.A.C. [Rule 62-213.410, F.A.C.]

TV7. **Circumvention.** No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly. [Rule 62-210.650, F.A.C.]

Compliance

TV8. **Compliance with Chapter 403, F.S., and Department Rules.** Except as provided at Rule 62-213.460, Permit Shield, F.A.C., the issuance of a permit does not relieve any person from complying with the requirements of Chapter 403, F.S., or Department rules. [Rule 62-4.070(7), F.A.C.]

TV9. **Compliance with Federal, State and Local Rules.** Except as provided at Rule 62-213.460, F.A.C., issuance of a permit does not relieve the owner or operator of a facility or an emissions unit from
complying with any applicable requirements, any emission limiting standards or other requirements of the air pollution rules of the Department or any other such requirements under federal, state, or local law. [Rule 62-210.300, F.A.C.]

TV10. Binding and Enforceable. The terms, conditions, requirements, limitations and restrictions set forth in this permit, are “permit conditions” and are binding and enforceable pursuant to Sections 403.141, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions. [Rule 62-4.160(1), F.A.C.]

TV11. Timely Information. 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 the 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. [Rule 62-4.160(15), F.A.C.]

TV12. Halting or Reduction of Source Activity. It shall not be a defense for a permittee in an enforcement action that maintaining compliance with any permit condition would necessitate halting of or reduction of the source activity. [Rule 62-213.440(1)(d)3., F.A.C.]

TV13. Final Permit Action. Any Title V source shall comply with all the terms and conditions of the existing permit until the Department has taken final action on any permit renewal or any requested permit revision, except as provided at Rule 62-213.412(2), F.A.C. [Rule 62-213.440(1)(d)4., F.A.C.]

TV14. Sudden and Unforeseeable Events Beyond the Control of the Source. A situation arising from sudden and unforeseeable events beyond the control of the source which causes an exceedance of a technology-based emissions limitation because of unavoidable increases in emissions attributable to the situation and which requires immediate corrective action to restore normal operation, shall be an affirmative defense to an enforcement action in accordance with the provisions and requirements of 40 CFR 70.6(g)(2) and (3), hereby adopted and incorporated by reference. [Rule 62-213.440(1)(d)5., F.A.C.]

TV15. Permit Shield. Except as provided in Chapter 62-213, F.A.C., compliance with the terms and conditions of a permit issued pursuant to Chapter 62-213, F.A.C., shall, as of the effective date of the permit, be deemed compliance with any applicable requirements in effect, provided that the source included such applicable requirements in the permit application. Nothing in this condition or in any permit shall alter or affect the ability of EPA or the Department to deal with an emergency, the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance, or the requirements of the Federal Acid Rain Program, the CAIR Program. [Rule 62-213.460, F.A.C.]

TV16. Compliance with Federal Rules. A facility or emissions unit subject to any standard or requirement of 40 CFR, Part 60, 61, 63 or 65, adopted and incorporated by reference at Rule 62-204.800, F.A.C., shall comply with such standard or requirement. Nothing in this chapter shall relieve a facility or emissions unit from complying with such standard or requirement, provided, however, that where a facility or emissions unit is subject to a standard established in Rule 62-296, F.A.C., such standard shall also apply. [Rule 62-296.100(3), F.A.C.]

Permit Procedures


TV18. Permit Renewal. The permittee shall renew its permit as required by Rules 62-4.090, 62.213.420(1) and 62-213.430(3), F.A.C. Permits being renewed are subject to the same requirements that apply to permit issuance at the time of application for renewal. Permit renewal applications shall contain that information identified in Rules 62-210.900(1) [Application for Air Permit - Long Form], 62-213.420(3) [required Information], 62-213.420(6) [CAIR Part Form], F.A.C. Unless a Title V source submits a timely and complete application for permit renewal in accordance with the requirements this rule, the existing permit

Okeelanta Corporation / New Hope Power Company
Sugar Mill and Sugar Refinery / Okeelanta Cogeneration Plant

Permit No. 0990005-033-AV
Title V Air Operation Permit
Page TV-2
shall expire and the source's right to operate shall terminate. For purposes of a permit renewal, a timely application is one that is submitted 225 days before the expiration of a permit that expires on or after June 1, 2009. No Title V permit will be issued for a new term except through the renewal process. [Rules 62-213.420 & 62-213.430, F.A.C.]

TV19. Insignificant Emissions Units or Pollutant-Emitting Activities. The permittee shall identify and evaluate insignificant emissions units and activities as set forth in Rule 62-213.430(6), F.A.C.

TV20. Savings Clause. If any portion of the final permit is invalidated, the remainder of the permit shall remain in effect. [Rule 62-213.440(1)(d1), F.A.C.]

TV21. Suspension and Revocation.
   a. Permits shall be effective until suspended, revoked, surrendered, or expired and shall be subject to the provisions of Chapter 403, F.S., and rules of the Department.
   b. Failure to comply with pollution control laws and rules shall be grounds for suspension or revocation.
   c. A permit issued pursuant to Chapter 62-4, F.A.C., shall not become a vested property right in the permittee. The Department may revoke any permit issued by it if it finds that the permit holder or his agent:
      (1) Submitted false or inaccurate information in his application or operational reports.
      (2) Has violated law, Department orders, rules or permit conditions.
      (3) Has failed to submit operational reports or other information required by Department rules.
      (4) Has refused lawful inspection under Section 403.091, F.S.
   d. No revocation shall become effective except after notice is served by personal services, certified mail, or newspaper notice pursuant to Section 120.60(7), F.S., upon the person or persons named therein and a hearing held if requested within the time specified in the notice. The notice shall specify the provision of the law, or rule alleged to be violated, or the permit condition or Department order alleged to be violated, and the facts alleged to constitute a violation thereof.
   [Rule 62-4.100, F.A.C.]

TV22. Not federally enforceable. Financial Responsibility. The Department may require an applicant to submit proof of financial responsibility and may require the applicant to post an appropriate bond to guarantee compliance with the law and Department rules. [Rule 62-4.110, F.A.C.]

TV23. Emissions Unit Reclassification.
   a. Any emissions unit whose operation permit has been revoked as provided for in Chapter 62-4, F.A.C., shall be deemed permanently shut down for purposes of Rule 62-212.500, F.A.C. Any emissions unit whose permit to operate has expired without timely renewal or transfer may be deemed permanently shut down, provided, however, that no such emissions unit shall be deemed permanently shut down if, within 20 days after receipt of written notice from the Department, the emissions unit owner or operator demonstrates that the permit expiration resulted from inadvertent failure to comply with the requirements of Rule 62-4.090, F.A.C., and that the owner or operator intends to continue the emissions unit in operation, and either submits an application for an air operation permit or complies with permit transfer requirements, if applicable.
   b. If the owner or operator of an emissions unit which is so permanently shut down, applies to the Department for a permit to reactivate or operate such emissions unit, the emissions unit will be reviewed and permitted as a new emissions unit.
   [Rule 62-210.300(6), F.A.C.]

TV24. Transfer of Permits. Per Rule 62-4.160(11), F.A.C., this permit is transferable only upon Department approval in accordance with Rule 62-4.120, 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. The permittee transferring the permit shall remain liable for corrective actions that may be required as a result of any violations occurring prior to the sale or legal transfer of the facility. The permittee shall also comply with the requirements of Rule 62-210.300(7), F.A.C., and use DEP Form No. 62-210.900(7). [Rules 62-4.160(11), 62-4.120, and 62-210.300(7), F.A.C.]
Rights, Title, Liability, and Agreements

TV25. Rights. As provided in Subsections 403.987(6) and 403.722(5), F.S., 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 this permit. [Rule 62-4.160(3), F.A.C.]

TV26. Title. 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. [Rule 62-4.160(4), (F.A.C.]

TV27. Liability. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department. [Rule 62-4.160(5), F.A.C.]

TV28. Agreements.

a. 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 reasonable times, access to the premises where the permitted activity is located or conducted to:
   (1) Have access to and copy any records that must be kept under conditions of the permit;
   (2) Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,
   (3) 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.

b. 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 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

c. 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.
[Rules 62-4.160(7), (9) and (10), F.A.C.]

Recordkeeping and Emissions Computation

TV29. Permit. The permittee shall keep this permit or a copy thereof at the work site of the permitted activity. [Rule 62-4.160(12), F.A.C.]

TV30. Recordkeeping.

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 five (5) 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, and the operating conditions at the time of sampling or measurement;
(2) The person responsible for performing the sampling or measurements;
(3) The dates analyses were performed;
(4) The person and company that performed the analyses;
(5) The analytical techniques or methods used;
(6) The results of such analyses.

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

TV31. Emissions Computation. Pursuant to Rule 62-210.370, F.A.C., the following required methodologies are to be used by the owner or operator of a facility for computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for computing emissions for purposes of the reporting requirements of subsection 62-210.370(3) and paragraph 62-212.300(1)(e), F.A.C., or of any permit condition that requires emissions be computed in accordance with Rule 62-210.370, F.A.C. Rule 62-210.370, F.A.C., is not intended to establish methodologies for determining compliance with the emission limitations of any air permit.

For any of the purposes specified above, the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.

a. Basic Approach. The owner or operator shall employ, on a pollutant-specific basis, the most accurate of the approaches set forth below to compute the emissions of a pollutant from an emissions unit; provided, however, that nothing in this rule shall be construed to require installation and operation of any continuous emissions monitoring system (CEMS), continuous parameter monitoring system (CPMS), or predictive emissions monitoring system (PEMS) not otherwise required by rule or permit, nor shall anything in this rule be construed to require performance of any stack testing not otherwise required by rule or permit.

(1) If the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute the emissions of the pollutant, unless the owner or operator demonstrates to the department that an alternative approach is more accurate because the CEMS represents still-emerging technology.

(2) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., but emissions of the pollutant can be computed pursuant to the mass balance methodology of paragraph 62-210.370(2)(c), F.A.C., the owner or operator shall use such methodology, unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

(3) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., and emissions cannot be computed pursuant to the mass balance methodology, the owner or operator shall use an emission factor meeting the requirements of paragraph 62-210.370(2)(d), F.A.C., unless the owner or operator demonstrates to the department that an alternative approach is more accurate.


(1) An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:

(a) The CEMS complies with the applicable certification and quality assurance requirements of 40 CFR Part 60, Appendices B and F, or, for an acid rain unit, the certification and quality assurance requirements of 40 CFR Part 75, all adopted by reference at Rule 62-204.800, F.A.C.; or,

(b) The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.

(2) Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:

(a) A calibrated flow meter that records data on a continuous basis, if available; or
(b) The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

(3) The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.


(1) An owner or operator may use mass balance calculations to compute emissions of a pollutant for purposes of this rule provided the owner or operator:
   (a) Demonstrates a means of validating the content of the pollutant that is contained in or created by all materials or fuels used in or at the emissions unit; and,
   (b) Assumes that the emissions unit emits all of the pollutant that is contained in or created by any material or fuel used in or at the emissions unit if it cannot otherwise be accounted for in the process or in the capture and destruction of the pollutant by the unit’s air pollution control equipment.

(2) Where the vendor of a raw material or fuel which is used in or at the emissions unit publishes a range of pollutant content from such material or fuel, the owner or operator shall use the highest value of the range to compute the emissions, unless the owner or operator demonstrates using site-specific data that another content within the range is more accurate.

(3) In the case of an emissions unit using coatings or solvents, the owner or operator shall document, through purchase receipts, records and sales receipts, the beginning and ending VOC inventories, the amount of VOC purchased during the computational period, and the amount of VOC disposed of in the liquid phase during such period.

d. Emission Factors.

(1) An owner or operator may use an emission factor to compute emissions of a pollutant for purposes of this rule provided the emission factor is based on site-specific data such as stack test data, where available, unless the owner or operator demonstrates to the department that an alternative emission factor is more accurate. An owner or operator using site-specific data to derive an emission factor, or set of factors, shall meet the following requirements.
   (a) If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid stack tests conducted during at least a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.
   (b) Multiple emission factors shall be used as necessary to account for variations in emission rate associated with variations in the emissions unit’s operating rate or operating conditions during the period over which emissions are computed.
   (c) The owner or operator shall compute emissions by multiplying the appropriate emission factor by the appropriate input, output or gas volume value for the period over which the emissions are computed. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.

(2) If site-specific data are not available to derive an emission factor, the owner or operator may use a published emission factor directly applicable to the process for which emissions are computed. If no directly-applicable emission factor is available, the owner or operator may use a factor based on a similar, but different, process.

e. Accounting for Emissions During Periods of Missing Data from CEMS, PEMS, or CPMS. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during
periods of missing data from CEMS, PEMS, or CPMS using other site-specific data to generate a reasonable estimate of such emissions.

f. **Accounting for Emissions During Periods of Startup and Shutdown.** In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.

g. **Fugitive Emissions.** In computing the emissions of a pollutant from a facility or emissions unit, the owner or operator shall account for the fugitive emissions of the pollutant, to the extent quantifiable, associated with such facility or emissions unit.

h. **Recordkeeping.** The owner or operator shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the department for any regulatory purpose.

[Rule 62-210.370(1) & (2), F.A.C.]

**Responsible Official**

TV32. **Designation and Update.** The permittee shall designate and update a responsible official as required by Rule 62-213.202, F.A.C.

**Prohibitions and Restrictions**

TV33. **Asbestos.** This permit does not authorize any demolition or renovation of the facility or its parts or components which involves asbestos removal. This permit does not constitute a waiver of any of the requirements of Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, National Emission Standard for Asbestos, adopted and incorporated by reference in Rule 62-204.800, F.A.C. Compliance with Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, Section 61.145, is required for any asbestos demolition or renovation at the source. [40 CFR 61; Rule 62-204.800, F.A.C.; and, Chapter 62-257, F.A.C.]

TV34. **Refrigerant Requirements.** Any facility having refrigeration equipment, including air conditioning equipment, which uses a Class I or II substance (listed at 40 CFR 82, Subpart A, Appendices A and B), and any facility which maintains, services, or repairs motor vehicles using a Class I or Class II substance as refrigerant must comply with all requirements of 40 CFR 82, Subparts B and F, and with Chapter 62-281, F.A.C.

TV35. **Open Burning Prohibited.** Unless otherwise authorized by Rule 62-296.320(3) or Chapter 62-256, F.A.C., open burning is prohibited.
UNREGULATED EMISSIONS UNITS AND/OR ACTIVITIES AND EXEMPTIONS

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”. Emissions units and activities meeting the requirements in Rule 62-213.430(6)(b), F.A.C. are also considered insignificant for purposes of Title V permitting.

**Okeelanta Corporation Sugar Mill and Refinery (ARMS ID No. 0990005)**

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<tr>
<th>ID No.</th>
<th>EU Description</th>
<th>Activities/Equipment</th>
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<tbody>
<tr>
<td>033</td>
<td>Sugar Refinery</td>
<td>- Bagging Machines</td>
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<td></td>
<td>Miscellaneous Support Equipment</td>
<td>- Bulk Curing, Wet Sugar and Portable Overflow Bins</td>
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<td>- Centrifugals</td>
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<td>- De-Sweeteners</td>
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<td>- Evaporators and Condensers</td>
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<td>- Large and Small Heaters</td>
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<td>- Primary and Secondary Filters</td>
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<td>- Refined Sugar Handling, Storage Silo, and Sugar/Syrup Mixer</td>
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<td>- Rotex Screens</td>
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<td>- Silo Scale</td>
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<td>- Sugar Refinery Process Tanks (Blackwater, Clarifier, Liquor, Melted Sugar Storage, Melter, Mixer, Reactor, Scums, Secondary Treatment, Sweetwater, Syrup Storage Tanks, and Phosphoric Acid Storage and Distribution System</td>
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<td>- Vacuum Pans with Condenser and non-Condensable Gas Vent</td>
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<td>- Isopropyl Alcohol Stored in Drums</td>
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<td>- Powdered Carbon Mixing Room</td>
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<td>- Refined Sugar Dust Collectors (Vented Inside Building)</td>
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<td>036</td>
<td>Shop Activities</td>
<td>- Surface Coating Operations (Non-RACT Vehicle Painting)</td>
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<td></td>
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<td>- Diesel Engine – Portable Air Compressor</td>
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<td>- Vehicle Repair (Body Shop)</td>
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<td>- Crawlers Repair Shop</td>
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<td>- Hydraulic Oil, Mineral Spirits, and Waste/Used Oil Storage Tanks</td>
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<td>- Mechanics’ Trucks With Portable Air Compressors (Gasoline Engines)</td>
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<td>- Portable Pressure Cleaners (Gasoline Engines)</td>
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<td>- Steam Clean Station</td>
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<td>- Truck, Trailer, Service Vehicles, Wheel Tractor Repair Shops</td>
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<td>- Cold Cleaning Devices (parts washer)</td>
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<td>- Containers for Oil/Grease/Used Oil</td>
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<td>- Oil/Water Separator/Skimmer Equipment</td>
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<td>- Portable Welders</td>
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<td>- Pressurized LPG Tanks</td>
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<td>- Stationary IC Engines</td>
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<td>- Vacuum Cleaning Systems</td>
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<td>- Vehicle Generated Dust</td>
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<td>- Woodworking and Metal Working Operations</td>
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<td>037</td>
<td>Sugar Mill Boiler House</td>
<td>- Boiler Blowdown Pipes &amp; Vents</td>
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<td>- Boiler Water Chemical Prep Tanks</td>
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<td>- Boiler Water Dearator and Tank</td>
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<td>038</td>
<td>Sugar Mill Cane Dumping Area</td>
<td>- Cane Dumping, Handling, and Storage Cane Knives, Shredding, and Conveying</td>
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<td>- Steam Clean Station</td>
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## Unregulated and Insignificant Emissions Units and/or Activities

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<tr>
<th>ID No.</th>
<th>EU Description</th>
<th>Activities/Equipment</th>
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<tbody>
<tr>
<td>039</td>
<td>Sugarcane Processing Facility</td>
<td>• Oil/Water Separator/Skimmer &lt;br&gt; • Bagacillo Cyclone and Handling Systems &lt;br&gt; • Batch Mixers (&lt;30 Cu. Ft.) &lt;br&gt; • Carbonaceous Fuel Conveying, Handling and Storage Piles &lt;br&gt; • Cold Cleaning Devices (Non-Halogenated Solvent) &lt;br&gt; • Containers For Oils/Wax/Grease &lt;br&gt; • Cooling Water Towers, Spray Ponds and Canals &lt;br&gt; • Covered Conveyors/Drop Points &lt;br&gt; • Diesel, Gasoline, Fuel Oil, Kerosene, Lube Oil, Waste and Used Oil Tanks &lt;br&gt; • Electric Ovens For Drying &lt;br&gt; • Emergency Generators &lt;br&gt; • Gear Boxes, Reducers Vents &lt;br&gt; • Handling Of Raw Sugar &lt;br&gt; • Industrial Waste Water Tanks (Non-MACT) &lt;br&gt; • Molasses Storage Tanks &lt;br&gt; • Mud Ponds &lt;br&gt; • Oil/Water Separator/Skimmer Equipment &lt;br&gt; • Painting Operations &lt;br&gt; • Portable Diesel Air Compressors &lt;br&gt; • Portable Electric Generators &lt;br&gt; • Portable Welders &lt;br&gt; • Pressurized LPG Tanks &lt;br&gt; • Process Water Filtration Intake Screens &lt;br&gt; • Process Wide Flanges and Valves &lt;br&gt; • Pump Operations &lt;br&gt; • Scrubber Water Ponds and Troughs &lt;br&gt; • Stationary Internal Combustion Engines (General) &lt;br&gt; • Vacuum Cleaning Systems &lt;br&gt; • Vehicle Generated Dust &lt;br&gt; • Vents From Hydraulic/Lube Oil Reservoirs &lt;br&gt; • Woodworking and Metal Working Operations &lt;br&gt; • Centrifugals With Mixers &lt;br&gt; • Crystallizers/Receivers &lt;br&gt; • Evaporator Cleaning Operations &lt;br&gt; • Evaporators (W/ Non-Condensable Gas Vent) &lt;br&gt; • Juice Heaters &lt;br&gt; • Mud Filter Condensers Vacuum Pumps &lt;br&gt; • Process Tanks (Batch, Clarified Juice, Coagulant Mix, Flash, Liming, Mingler, Mixer, Mud Mixing, Pan Feed, Magma, Mud Waste, Muriatic, Sugar Receiver, and Syrup Storage) &lt;br&gt; • Isopropyl alcohol stored in drums &lt;br&gt; • Isopropyl alcohol usage in vacuum pans &lt;br&gt; • Rotary Vacuum Filters &lt;br&gt; • Vacuum Pans with NCG vents, Condensers, And Pumps &lt;br&gt; • Lime Storage Silo and Distribution Systems &lt;br&gt; • Lime Silo Baghouse (5% Opacity) &lt;br&gt; • Diesel Engines for Operation of IWW Pumps &lt;br&gt; • Phosphoric Acid Storage and Distribution Systems &lt;br&gt; • Sodium Hydroxide Storage and Distribution Systems &lt;br&gt; • Mill Crown Wheel Removal Operations &lt;br&gt; • Vertical Molasses Crystallizer &lt;br&gt; • Cane Mills &lt;br&gt; • Cush-cush Screens/Conveyors and DSM Screens</td>
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### SECTION 4. APPENDIX UI

#### Unregulated and Insignificant Emissions Units and/or Activities

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<tr>
<th>ID No.</th>
<th>EU Description</th>
<th>Activities/Equipment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>- Hydrochloric Acid Tanks</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Mill Turbines with Vents</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Carbon Slurry Tank</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Condensate Tank</td>
</tr>
<tr>
<td>040</td>
<td>Facility Fuel Tank Farm</td>
<td>- Diesel, Gasoline and Oil Tanks</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Diesel and Gasoline Pumps and Loading Arms</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Oil/Water Separator/Skimmer Equipment</td>
</tr>
<tr>
<td>041</td>
<td>Facility Potable Water System</td>
<td>- Hydrogen Sulfide Degasifiers</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Membrane Cleaning Chemicals and Process Water Discharge Canal</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Sulfuric Acid Storage and Distribution Systems</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Disinfection System</td>
</tr>
<tr>
<td>042</td>
<td>Facility Sewer Plant</td>
<td>- Sewage Treatment Plant</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Collection and Distribution Lift Station</td>
</tr>
<tr>
<td>044</td>
<td>Okeelanta Facility - Miscellaneous Unregulated Activities</td>
<td>- Forklift and crane operations</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Bagasse conveyors to cogeneration boilers or biomass storage.</td>
</tr>
<tr>
<td>050</td>
<td>Transhipment Facility, Miscellaneous Support Equipment</td>
<td>- Containers for Oil/Grease/Ink</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Diesel Fire Pump Engine</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Diesel Tank</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Vehicle Generated Dust</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Refined Sugar Dust Collectors (Vented Inside Building)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Portable Vacuum Cleaners</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Propane-Fired Water Heaters for Disinfection Process Vessels</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Steam Clean Station</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Cold Cleaning Devices (Parts Washer)</td>
</tr>
</tbody>
</table>

The following activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

<table>
<thead>
<tr>
<th>ID No.</th>
<th>EU Description</th>
<th>Activities/Equipment</th>
</tr>
</thead>
<tbody>
<tr>
<td>056</td>
<td>Hi-Vac Industrial Vacuum System</td>
<td>Sugar Mill and Refinery</td>
</tr>
<tr>
<td>053</td>
<td>Printing Operation</td>
<td>Trans-shipment</td>
</tr>
</tbody>
</table>

The following emission units have been determined by the Department to be EXEMPT from permitting.

<table>
<thead>
<tr>
<th>ID No.</th>
<th>EU Description</th>
<th>Activities/Equipment</th>
</tr>
</thead>
<tbody>
<tr>
<td>057</td>
<td>Specialty Sugar Product</td>
<td>300 hp gas-fired package boiler (Refined Sugar Warehouse No. 3)</td>
</tr>
<tr>
<td>058</td>
<td>Sugar Bin with Dust Collector</td>
<td>(Refined Sugar Warehouse # 3)</td>
</tr>
<tr>
<td>052</td>
<td>Bulk Transfer Station</td>
<td>Wet Roto-clone No. 5</td>
</tr>
<tr>
<td>051</td>
<td>Refined Sugar Silo</td>
<td>Baghouse</td>
</tr>
<tr>
<td>029</td>
<td>Packaging Line 10</td>
<td>Baghouse (Located in Sugar Refinery)</td>
</tr>
</tbody>
</table>

- Sugar bin with dust collector (refined sugar warehouse #3)*
- Refined Sugar Silo – Baghouse*
- Packaging Line 10 Baghouse (Located in Sugar Refinery)*

*These emission units have been determined by the Department to be exempt from permitting.
SECTION 4. APPENDIX UI
Unregulated and Insignificant Emissions Units and/or Activities

New Hope Power Cogeneration Plant (ARMS ID No. 09900332)

<table>
<thead>
<tr>
<th>ID No.</th>
<th>EU Description</th>
<th>Activities/Equipment</th>
</tr>
</thead>
<tbody>
<tr>
<td>005</td>
<td>Cogeneration Plant - Miscellaneous support equipment</td>
<td>• 50,000 gallon distillate oil tank</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Nominal 75 MW Steam Turbine Electrical Generator</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Nominal 65 MW Steam Turbine Electrical Generator</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Condensers</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Two Cooling Towers</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Switchyard, etc.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Boiler Drum Blowdown Tank</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Diesel Fire Pump Engine</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Propane Tank</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Hydrogen Sulfide Degasifier</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Oil/water Separators</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Sodium Hydroxide Tank</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Wastewater Neutralization Tank</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Cold Cleaning Devices (Parts Washers)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Sulfuric Acid Storage and Distribution Systems</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Painting Operations</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Portable Diesel Air Compressors</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Portable Electric Generators</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Portable Welders</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Pressurized LPG Tanks</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Portable Pumps</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Forklift, loader and crane operations</td>
</tr>
</tbody>
</table>
NEW SOURCE PERFORMANCE STANDARDS

Subpart A-General Provisions for 40 CFR 60
[Source: Federal Register dated 7/1/98, Federal Register 5/8/98, 2/12/99, 10/17/00, 6/28/02, 6/1/06]

Cogeneration Boilers (EUs 001, 002 and 003) (Boiler 16 (EU 014) is DELETED)

In accordance with Rule 62-204.800(8), F.A.C., the cogeneration boilers are subject to the applicable requirements of 40 CFR 60 Subpart A, General Provisions. For these requirements, the original rule numbering has been retained.

40 CFR 60.1 Applicability.

(a) Except as provided in 40 CFR 60 subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (CAA) as amended November 15, 1990 (42 U.S.C. 7661).

40 CFR 60.5 Determination of construction or modification.

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

40 CFR 60.6 Review of plans.

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b)(1) A separate request shall be submitted for each construction or modification project.

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.
40 CFR 60.7 Notification and record keeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

(1) A notification of the date construction (or reconstruction as defined under § 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

(2) Reserved.

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in § 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 CFR 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5) of 40 CFR 60. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) Each owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) The summary report form shall contain the information and be in the format shown in Figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

{See Figure 1, Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance, at the end of this section.}

(e) (1) Notwithstanding the frequency of reporting requirements specified in paragraph (c) of this section, an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility’s excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in paragraph (e)(2) of this section.

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source’s entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator’s conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source’s potential for noncompliance in the future. If the Administrator disapproves the owner or operator’s request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator’s intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in paragraphs (e)(1) and (e)(2) of this section.
(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (f) of this section, if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

(g) If notification substantially similar to that in 40 CFR 60.7(a) is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of 40 CFR 60.7(a).

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

[40 CFR 60.7(a), (b), (c), (d), (e), (f), (g), (h)]

40 CFR 60.8 Performance tests.

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

[40 CFR 60.8(a)]

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in 40 CFR 60.8 shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

[40 CFR 60.8(b)(1), (2), (3), (4) & (5)]
Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard. [40 CFR 60.8(c)].

The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

1. Sampling ports adequate for test methods applicable to such facility. This includes
   (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and
   (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

2. Safe sampling platform(s).

3. Safe access to sampling platform(s).

4. Utilities for sampling and testing equipment.

[40 CFR 60.8(e)].

Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs. [40 CFR 60.8(f)].

§ 60.9 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§ 60.5 and 60.6 is governed by §§ 2.201 through 2.213 of this chapter and not by § 2.301 of this chapter.)

40 CFR 60.10 State authority.

The provisions of 40 CFR 60 shall not be construed in any manner to preclude any State or political subdivision thereof from:
(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

[40 CFR 60.10(a) and (b)].

40 CFR 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5). For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in 40 CFR 60.8 unless one of the following conditions apply. If no performance test under 40 CFR 60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under 40 CFR 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in 40 CFR 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under 40 CFR 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in 40 CFR 60.11(e)(5), the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of 40 CFR 60, has
been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in 40 CFR 60.11(e)(3), the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with 40 CFR 60.11(b), shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under 40 CFR 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in 40 CFR 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of 40 CFR 60.7(e)(1) shall apply.

(4) The owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by 40 CFR 60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and 40 CFR 60.8 performance test results.

(5) The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine compliance with the opacity standard.

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by 40 CFR 60.8, the opacity observation results and observer certification required by 40 CFR 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by 40 CFR 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with 40 CFR 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, the shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed...
under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart of 40 CFR 60 shall supersede any conflicting provisions of 40 CFR 60.11.
[40 CFR 60.11(a), (b), (c), (d), (e) and (f)]

40 CFR 60.12 Circumvention.

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.
[40 CFR 60.12]

40 CFR 60.13 Monitoring requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under 40 CFR 60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continues opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he/she shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 40 CFR 60.8 and as described in 40 CFR 60.11(e)(5), shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 40 CFR 60.8 is conducted.

(2) Except as provided in 40 CFR 60.13(c)(1), the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.
(d) (1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall 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.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of 40 CFR 60 shall be used.

(g) (1) When more than one continuous monitoring system is used to measure the emissions from only one affected facility (e.g. multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless installation of fewer systems is approved by the Administrator.

(2) When the effluents from two or more affected facilities subject to the same opacity standard are combined before being released to the atmosphere, the owner or operator may either install a continuous opacity monitoring system at a location monitoring the combined effluent or install an opacity combiner system comprised of opacity and flow monitoring systems on each stream, and shall report as per Sec. 60.7(c) on the combined effluent. When the affected facilities are not subject to the same opacity standard applicable, except for documented periods of shutdown of the affected facility, subject to the most stringent opacity standard shall apply.

(3) When the effluents from two or more affected facilities subject to the same emissions standard, other than opacity, are combined before released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the continuous monitoring standard, separate continuous monitoring systems shall be installed on each effluent and the owner or operator shall report as required for each affected facility.
(h) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. For owners or operators complying with the requirements in Sec. 60.7(f)(1) or (2), data averages must include any data recorded during periods of monitor breakdown or malfunction. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non reduced form (e.g., ppm pollutant and percent O2 or ng or pollutant per J of heat input). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).

[iRule 62-296.800, F.A.C.; 40 CFR 60.13(h)].

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities is released to the atmosphere through more than one point.

[iRule 62-296.800, F.A.C.; 40 CFR 60.13(i)].

(j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining RA is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the RA test in section 8.4 of Performance Specification 2 and substitute the procedures in section 16.0 if the results of a performance test conducted according to the requirements in 40 CFR 60.8 of this subpart or other tests performed following the criteria in 40 CFR 60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards
expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the RA test and substitute the procedures in section 16.0 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the RA test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure that the CEMS data indicate the source emissions approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., 40 CFR 60.45(g)(2) and 40 CFR 60.73(e), and 40 CFR 60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in section 8.4 of Performance Specification 2.

[Rule 62-296.800, F.A.C.; 40 CFR 60.13(j)].

40 CFR 60.14  Modification.

(a) Except as provided under 40 CFR 60.14(e) and 40 CFR 60.14(f), any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility 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.

[Rule 62-296.800, F.A.C.; 40 CFR 60.14(a)].

(b) Emission rate shall be expressed as kg/hr (lbs./hour) of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors", EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in 40 CFR 60.14(b)(1) does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in 40 CFR 60.14(b)(1). When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in 40 CFR 60 appendix C of 40 CFR 60 shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions...
as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

[Rule 62-296.800, F.A.C.; 40 CFR 60.14(b)].

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

[Rule 62-296.800, F.A.C.; 40 CFR 60.14(c)].

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:

1. Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of 40 CFR 60.14(c) and 40 CFR 60.15.

2. An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

3. An increase in the hours of operation.

4. Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by 40 CFR 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

5. The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

6. The relocation or change in ownership of an existing facility.

[Rule 62-296.800, F.A.C.; 40 CFR 60.14(e)].

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.


(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in 40 CFR 60.14(a), compliance with all applicable standards must be achieved.

[Rule 62-296.800, F.A.C.; 40 CFR 60.14(g)].

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(i) Repowering projects that are awarded funding from the Department of Energy as permanent clean coal technology demonstration projects (or similar projects funded by EPA) are exempt from the requirements of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.
(j) (1) Repowering projects that qualify for an extension under section 409(b) of the Clean Air Act are exempt from the requirements of this section, provided that such change does not increase the actual hourly emissions of any pollutant regulated under this section above the actual hourly emissions achievable at that unit during the 5 years prior to the change.

(2) This exemption shall not apply to any new unit that:
   (i) Is designated as a replacement for an existing unit;
   (ii) Qualifies under section 409(b) of the Clean Air Act for an extension of an emission limitation compliance date under section 405 of the Clean Air Act; and
   (iii) Is located at a different site than the existing unit.

(k) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project is exempt from the requirements of this section. A temporary clean coal control technology demonstration project, for the purposes of this section is a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(l) The reactivation of a very clean coal-fired electric utility steam generating unit is exempt from the requirements of this section.

40 CFR 60.15 Reconstruction.

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.
   [Rule 62-296.800, F.A.C.; 40 CFR 60.15(a)].

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:
   (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and
   (2) It is technologically and economically feasible to meet the applicable standards set forth in this part.
   [Rule 62-296.800, F.A.C.; 40 CFR 60.15(b)].

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.
   [Rule 62-296.800, F.A.C.; 40 CFR 60.15(c)].

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:
   (1) Name and address of the owner or operator.
   (2) The location of the existing facility.
   (3) A brief description of the existing facility and the components which are to be replaced.
   (4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.
   (5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.
   (6) The estimated life of the existing facility after the replacements.
   (7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.
(e) The Administrator will determine, within 30 days of the receipt of the notice required by 40 CFR 60.15(d) and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under 40 CFR 60.15(e) shall be based on:

   1. The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;
   2. The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;
   3. The extent to which the components being replaced cause or contribute to the emissions from the facility; and
   4. Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

§ 60.18 General control device requirements.

(a) Introduction. This section contains requirements for control devices used to comply with applicable subparts of parts 60 and 61. The requirements are placed here for administrative convenience and only apply to facilities covered by subparts referring to this section.

(b) Flares. Paragraphs (c) through (f) apply to flares.

(c) (1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

   (2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

   (3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

      (i) (A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity, V_{max}, as determined by the following equation:

      \[ V_{max} = (X_{H2} - K1) \times K2 \]

      Where:

      \( V_{max} \) = Maximum permitted velocity, m/sec.

      \( K1 \) = Constant, 6.0 volume-percent hydrogen.

      \( K2 \) = Constant, 3.9(m/sec)/volume-percent hydrogen.

      \( X_{H2} \) = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in § 60.17).

      (B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

      (ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas
being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4) (i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4)(ii) and (iii) of this section.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, Vmax, as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, Vmax, as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

(d) Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

(e) Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(f) (1) Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

\[
H_T = \sum_{i=1}^{n} C_i H_i
\]

where:

\(H_T=\text{Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;}

\[K = \text{Constant, } 1.740 \times 10^{-7} \left( \frac{1}{\text{ppm}} \right) \left( \frac{\text{g mole}}{\text{scm}} \right) \left( \frac{\text{MJ}}{\text{cal}} \right)\]

\[\text{where the standard temperature for } \frac{\text{g mole}}{\text{scm}} \text{ is } 20^\circ \text{C};\]

\[C_i = \text{Concentration of sample component } i \text{ in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (Incorporated by reference as specified in § 60.17); and}

\[H_i = \text{Net heat of combustion of sample component } i \text{, kcal/g mole at } 25^\circ \text{C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in § 60.17) if published values are not available or cannot be calculated.}\]

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.
(5) The maximum permitted velocity, $V_{\text{max}}$, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation. 
\[ \log_{10}(V_{\text{max}}) = \frac{HT+28.8}{31.7} \]

$V_{\text{max}}$=Maximum permitted velocity, M/sec
28.8=Constant
31.7=Constant
HT=The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity, $V_{\text{max}}$, for air-assisted flares shall be determined by the following equation.
\[ V_{\text{max}} = 8.706 + 0.7084 \times HT \]

$V_{\text{max}}$=Maximum permitted velocity, m/sec
8.706=Constant
0.7084=Constant
HT=The net heating value as determined in paragraph (f)(3).

§ 60.19 General notification and reporting requirements.

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word “calendar” is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be post-marked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the post-mark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State’s schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted.
throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f) (1) (i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator’s judgment, an owner or operator’s request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.
Figure 1. Summary Report  
Gaseous and Opacity Excess Emission and Monitoring System Performance  

Company: ____________________________________________________________

Address: _____________________________________________________________

Process Unit(s) Description: _______________________________________________________________________________________

Emission Limitation: _______________________________________________________________________________________________

Pollutant (Circle One): SO₂  NOₓ  TRS  H₂S  CO  Opacity  

Reporting Period Dates: From __________________________ to __________________________

Total source operating time in reporting period ¹: ____________________________

Monitor Manufacturer: _______________________________________________________________________________________________

Monitor Model No.: ________________________________________________________________________________________________

Date of Latest CMS Certification or Audit: _____________________________

<table>
<thead>
<tr>
<th>Emission Data Summary ¹</th>
<th>CMS Performance Summary ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Duration of excess emissions in reporting period due to:</td>
<td>1. CMS downtime in reporting period due to:</td>
</tr>
<tr>
<td>a. Startup/shutdown ........................................</td>
<td>a. Monitor equipment malfunctions ...............</td>
</tr>
<tr>
<td>b. Control equipment problems ...........................</td>
<td>b. Non-Monitor equipment malfunctions ..........</td>
</tr>
<tr>
<td>c. Process problems ........................................</td>
<td>c. Quality assurance calibration ...............</td>
</tr>
<tr>
<td>d. Other known causes .....................................</td>
<td>d. Other known causes .........................</td>
</tr>
<tr>
<td>e. Unknown causes ...........................................</td>
<td>e. Unknown causes ...............................</td>
</tr>
<tr>
<td>2. Total duration of excess emissions ...................</td>
<td>2. Total CMS Downtime ..............................</td>
</tr>
<tr>
<td>3. [Total duration of excess emissions] x (100%) [Total source operating time] ............... % ²</td>
<td>3. [Total CMS Downtime] x (100%) [Total source operating time] ...... % ²</td>
</tr>
</tbody>
</table>

¹ For opacity, record all times in minutes. For gases, record all times in hours.

² For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

On a separate page, describe any changes since last quarter in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: ____________________________

Signature: ____________________________

Title: ____________________________

Date: ____________________________

---

Okeelanta Corporation / New Hope Power Company  
Sugar Mill and Sugar Refinery / Okeelanta Cogeneration Plant  

Permit No. 0990005-033-AV  
Title V Air Operation Permit
NEW SOURCE PERFORMANCE STANDARDS

Cogeneration Boilers (EUs 001, 002 and 003)

In accordance with Rule 62-204.800(8), F.A.C., the cogeneration boilers are subject to the applicable requirements of 40 CFR 60 Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for which Construction Is Commenced after September 18, 1978. For these requirements, the original rule numbering has been retained.

§ 60.50a Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each municipal waste combustor unit with a municipal waste combustor unit capacity greater than 225 megagrams per day (250 tons per day) of municipal solid waste for which construction, modification, or reconstruction is commenced as specified in paragraphs (a)(1) and (a)(2) of this section.

(1) Construction is commenced after December 20, 1989 and on or before September 20, 1994.

(2) Modification or reconstruction is commenced after December 20, 1989 and on or before June 19, 1996.

(b) [Reserved]

(c) [Not applicable.]

(d) Any cofired combustor, as defined under § 60.51a, located at a plant that meets the capacity specifications in paragraph (a) of this section is not subject to this subpart if the owner or operator of the cofired combustor:

(1) Notifies the Administrator of an exemption claim;

(2) Provides a copy of the federally enforceable permit (specified in the definition of cofired combustor in this section); and

(3) Keeps a record on a calendar quarter basis of the weight of municipal solid waste combusted at the cofired combustor and the weight of all other fuels combusted at the cofired combustor.

(e) Any cofired combustor that is subject to a federally enforceable permit limiting the operation of the combustor to no more than 225 megagrams per day (250 tons per day) of municipal solid waste is not subject to this subpart.

(f) [Not applicable.]

(g) A qualifying small power production facility, as defined in section 3(17)(C) of the Federal Power Act (16 U.S.C. 796(17)(C)), that burns homogeneous waste (such as automotive tires or used oil, but not including refuse-derived fuel) for the production of electric energy is not subject to this subpart if the owner or operator of the facility notifies the Administrator of an exemption claim and provides data documenting that the facility qualifies for this exemption.

(h) A qualifying cogeneration facility, as defined in section 3(18)(B) of the Federal Power Act (16 U.S.C. 796(18)(B)), that burns homogeneous waste (such as automotive tires or used oil, but not including refuse-derived fuel) for the production of electric energy and steam or forms of useful energy (such as heat) that are used for industrial, commercial, heating, or cooling purposes, is not subject to this subpart if the owner or operator of the facility notifies the Administrator of an exemption claim and provides data documenting that the facility qualifies for this exemption.

(i) through (k) [Not applicable.]

(l) The following authorities shall be retained by the Administrator and not transferred to a State: None.

(m) This subpart shall become effective on August 12, 1991.

Okeelanta Corporation / New Hope Power Company
Sugar Mill and Sugar Refinery / Okeelanta Cogeneration Plant

Permit No. 0990005-033-AV
Title V Air Operation Permit

Page 60Da-1
§ 60.51a Definitions.

*Calendar quarter* means a consecutive 3-month period (non-overlapping) beginning on January 1, April 1, July 1, and October 1.

*Clean wood* means untreated wood or untreated wood products including clean untreated lumber, tree stumps (whole or chipped), and tree limbs (whole or chipped). Clean wood does not include yard waste, which is defined elsewhere in this section, or construction, renovation, and demolition wastes (which includes but is not limited to railroad ties and telephone poles), which are exempt from the definition of municipal solid waste in this section.

*Cofired combustor* means a unit combusting municipal solid waste with non-municipal solid waste fuel (e.g., coal, industrial process waste) and subject to a federally enforceable permit limiting the unit to combusting a fuel feed stream, 30 percent or less of the weight of which is comprised, in aggregate, of municipal solid waste as measured on a calendar quarter basis.

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

*Municipal solid waste* or *municipal-type solid waste* or *MSW* means household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, non-manufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, non-medical waste discarded by hospitals, material discarded by non-manufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional waste does not include used oil; sewage sludge; wood pallets; construction, renovation, and demolition wastes (which includes but is not limited to railroad ties and telephone poles); clean wood; industrial process or manufacturing wastes; medical waste; or motor vehicles (including motor vehicle parts or vehicle fluff). Household, commercial/retail, and institutional wastes include:

1. Yard waste;
2. Refuse-derived fuel; and
3. Motor vehicle maintenance materials limited to vehicle batteries and tires except as specified in § 60.50a(c).

*Untreated lumber* means wood or wood products that have been cut or shaped and include wet, air-dried, and kiln-dried wood products. Untreated lumber does not include wood products that have been painted, pigment-stained, or “pressure-treated.” Pressure-treating compounds include, but are not limited to, chromate copper arsenate, pentachlorophenol, and creosote.

*Yard waste* means grass, grass clippings, bushes, shrubs, and clippings from bushes and shrubs that are generated by residential, commercial/retail, institutional, and/or industrial sources as part of maintenance activities associated with yards or other private or public lands. Yard waste does not include construction, renovation, and demolition wastes, which are exempt from the definition of MSW in this section. Yard waste does not include clean wood, which is exempt from the definition of MSW in this section.

1. **NSPS Subpart Da**: The permittee shall comply with the following applicable requirements of 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978.

Okeelanta Corporation / New Hope Power Company Permit No. 0990005-033-AV
Sugar Mill and Sugar Refinery / Okeelanta Cogeneration Plant Title V Air Operation Permit
Page 60Da-2
§ 60.40Da Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) [Not applicable.]

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

§ 60.41Da Definitions.

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

[Only pertinent definitions have been included]

Boiler operating day for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours.

Cogeneration, also known as “combined heat and power”, means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Electric utility company means the largest interconnected organization, business, or governmental entity that generates electric power for sale (e.g., a holding company with operating subsidiary companies).

Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. For the purpose of this subpart, net-electric output is the gross electric sales to the utility power distribution system minus purchased power on a 12-month rolling average. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

Electrostatic precipitator or ESP means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

Emission limitation means any emissions limit or operating limit.

Emission rate period means any calendar month included in a 12-month rolling average period.

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

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, and coke-oven gas.

Gross output means the gross useful work performed by the steam generated. For units generating only
electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For
cogeneration units, the gross useful work performed is the gross electrical output plus 75 percent of the useful
thermal output measured relative to ISO conditions that is not used to generate additional electrical or
mechanical output (i.e., steam delivered to an industrial process).

24-hour period means the period of time between 12:01 a.m. and 12:00 midnight.

Interconnected means that two or more electric generating units are electrically tied together by a network of
power transmission lines, and other power transmission equipment.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3
kilopascals.

Natural gas means:
(1) A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations
beneath the earth’s surface, of which the principal constituent is methane; or
(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials (ASTM) Standard
Specification for Liquid Petroleum Gases D1835-87, 91, 97, or 03a (incorporated by reference, see Sec. 60.17).

Neighboring company means any one of those electric utility companies with one or more electric power
interconnections to the principal company and which have geographically adjoining service areas.

Net system capacity means the sum of the net electric generating capability (not necessarily equal to rated
capacity) of all electric generating equipment owned by an electric utility company (including steam generating
units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric
generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has
the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under
multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is
otherwise established by contractual arrangement.

Petroleum means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate,
residual oil, and petroleum coke.

Potential combustion concentration means the theoretical emissions (ng/J, lb/million Btu heat input) that would
result from combustion of a fuel in an uncleaned state without emission control systems) and:
(a) For particulate matter is:
   (1) 3,000 ng/J (7.0 lb/million Btu) heat input for solid fuel; and
   (2) 73 ng/J (0.17 lb/million Btu) heat input for liquid fuels.
(b) For sulfur dioxide is determined under Sec. 60.48Da(b).
(c) For nitrogen oxides is:
   (1) 290 ng/J (0.67 lb/million Btu) heat input for gaseous fuels;
   (2) 310 ng/J (0.72 lb/million Btu) heat input for liquid fuels; and
   (3) 990 ng/J (2.30 lb/million Btu) heat input for solid fuels.

Resource recovery unit means a facility that combusts more than 75 percent non-fossil fuel on a quarterly
(calendar) heat input basis.

Solid-derived fuel means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating
useful heat and includes, but is not limited to, solvent refined coal, liquefied coal, and gasified coal.
Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

§ 60.42Da Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the particulate matter performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(c) and (d) [Not applicable.]

§ 60.43Da Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain sulfur dioxide in excess of:

(1) 520 ng/J (1.20 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/million Btu) heat input.

(b) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain sulfur dioxide in excess of:

(1) 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC–I) any gases that contain SO₂ in excess of 520 ng/J (1.20 lb/MMBtu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this
section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/MMBtu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite;
(2) Is classified as a resource recovery unit; or
(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/MMBtu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an \( \text{SO}_2 \) commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

\[
\begin{align*}
\text{E}_s &= (340x+520y)/100 \\
%P_s &= 10 \\
\text{or}
\end{align*}
\]

\[
\begin{align*}
\text{E}_s &= (340x+520y)/100 \\
%P_s &= (10x+30y)/100 \\
\end{align*}
\]

where:

- \( \text{E}_s \) is the prorated sulfur dioxide emission limit (ng/J heat input),
- \( %P_s \) is the percentage of potential sulfur dioxide emission allowed.
- \( x \) is the percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels)
- \( y \) is the percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels)

(i) through (k) {Not applicable.}

\section*{§ 60.44Da Standard for nitrogen oxides.}

(a) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b) and (d) of this section, any gases which contain nitrogen oxides (expressed as \( \text{NO}_2 \)) in excess of the following emission limits, based on a 30-day rolling average, except as provided under § 60.46Da(j)(1):

\[(1) \ \text{NO}_x \text{ emission limits.} \]
### NSPS Subpart Da, Electric Utility Steam Generating Units

#### SECTION 4. APPENDIX 60Da

<table>
<thead>
<tr>
<th>Fuel type</th>
<th>Emission limit for heat input</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>ng/J</td>
<td>(lb/MMBtu)</td>
</tr>
<tr>
<td>Gaseous fuels:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>All other fuels</td>
<td>86</td>
<td>0.20</td>
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<td>Liquid fuels:</td>
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<td></td>
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<tr>
<td>All other fuels</td>
<td>130</td>
<td>0.30</td>
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<tr>
<td>Solid fuels:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>All other fuels</td>
<td>260</td>
<td>0.60</td>
</tr>
</tbody>
</table>

(2) \( \text{NO}_x \) reduction requirement.

<table>
<thead>
<tr>
<th>Fuel type</th>
<th>Percent reduction of potential combustion concentration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gaseous fuels</td>
<td>25%</td>
</tr>
<tr>
<td>Liquid fuels</td>
<td>30%</td>
</tr>
<tr>
<td>Solid fuels</td>
<td>65%</td>
</tr>
</tbody>
</table>

(b) \emph{(Not applicable.)}

(c) Except as provided under paragraph (d) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

\[
E_n = \left[86 \, w + 130 \, x + 210 \, y + 260 \, z + 340 \, v \right]/100
\]

where:

- \( E_n \) is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);
- \( w \) is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;
- \( x \) is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;
- \( y \) is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;
- \( z \) is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and
- \( v \) is the percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(d) through (f) \emph{(Not applicable.)}

§ 60.45Da Standard for mercury.

(a) and (b) \emph{(Not applicable.)}

§ 60.46Da [Reserved]

§ 60.47Da Commercial demonstration permit.

(a) through (e) \emph{(Not applicable.)}

§ 60.48Da Compliance provisions.
(a) Compliance with the particulate matter emission limitation under Sec. 60.42Da(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under Sec. 60.42Da(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under Sec. 60.44Da(a) constitutes compliance with the percent reduction requirements under Sec. 60.44Da(a)(2).

(c) The particulate matter emission standards under Sec. 60.42Da, the nitrogen oxides emission standards under Sec. 60.44Da, and the Hg emission standards under Sec. 60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(d) [Not applicable.]

(e) Compliance with the sulfur dioxide emission limitations and percentage reduction requirements under Sec. 60.43Da and the nitrogen oxides emission limitations under Sec. 60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under Sec. 60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under Sec. 60.43Da and the nitrogen oxides emission limitation under Sec. 60.44Da is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

1. Compliance with applicable 30-day rolling average SO₂ and NOₓ emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO₂ and NOₓ for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NOₓ only), or emergency conditions (SO₂ only).

2. Compliance with applicable SO₂ percentage reduction requirements is determined based on the average inlet and outlet SO₂ emission rates for the 30 successive boiler operating days.

3. Compliance with applicable daily average particulate matter emission limitations is determined by calculating the arithmetic average of all hourly emission rates for particulate matter each boiler operating day, except for data obtained during startup, shutdown, and malfunction.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under Sec. 60.49Da of this subpart, compliance of the affected facility with the emission requirements under Secs. 60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19.

(i) through (p) [Not applicable.]

§ 60.49Da Emission monitoring.

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is
the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

(2) {Not applicable.}

(3) An “as fired” fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of this section.

c) (1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a nitrogen oxides emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of Sec. 60.51Da. Data reported to meet the requirements of Sec. 60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f) (1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for 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, supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) {Not applicable.}

(g) The 1-hour averages required under paragraph Sec. 60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under Sec. 60.48Da. The 1-hour averages are calculated using the data points required under Sec. 60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in
(1) Method 6 shall be used to determine the \( \text{SO}_2 \) concentration at the same location as the \( \text{SO}_2 \) monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 shall be used to determine the \( \text{NO}_X \) concentration at the same location as the \( \text{NO}_X \) monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the \( \text{O}_2 \) or \( \text{CO}_2 \) concentration at the same location as the \( \text{O}_2 \) or \( \text{CO}_2 \) monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (1b/million Btu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under Sec. 60.13(c) and calibration checks under Sec. 60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7, as applicable, shall be used to determine \( \text{O}_2 \), \( \text{SO}_2 \), and \( \text{NO}_X \) concentrations.

(2) \( \text{SO}_2 \) or \( \text{NO}_X \) (NO), as applicable, shall be used for preparing the calibration gas mixtures (in \( \text{N}_2 \), as applicable) under Performance Specification 2 of Appendix B of this part.

(3) [Not applicable.]

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125% of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50% of maximum estimated hourly potential emissions of the fuel fired.

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

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under paragraph (i) of this section, the conditions under Sec. 60.46(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.

(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(4) For Method 3B, Method 3A may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under Sec. 60.44Da(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in megawatt-hour on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam
output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under Sec. 60.42Da, Sec. 60.43Da, Sec. 60.44Da, or Sec. 60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of Appendix B and procedure 1 of Appendix F of this subpart, and record the output of the system, for measuring the flow of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23, may be used.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of Appendix D of 40 CFR part 75.

(o) through (v) [Not applicable.]

§ 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in Sec. 60.8, the owner or operator shall use as reference methods and procedures the methods in Appendix A of this part or the methods and procedures as specified in this section, except as provided in Sec. 60.8(b). Section 60.8(f) does not apply to this section for SO₂ and NOₓ. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner/operator shall determine compliance with particulate matter standards in Sec. 60.42Da as follows:

(1) The dry basis F factor (O₂) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

(2) For the particulate matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 ± 14° C (320 ± 25° F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O₂ concentration. The O₂ sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O₂ traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O₂ traverse points. If the grab sampling procedure is used, the O₂ concentration for the run shall be the arithmetic mean of the sample O₂ concentrations at all traverse points.

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

(c) The owner or operator shall determine compliance with the SO₂ standards in Sec. 60.43Da as follows:

(1) through (3) [Not applicable.]
SECTION 4. APPENDIX 60Da
NSPS Subpart Da, Electric Utility Steam Generating Units

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring system in Sec. 60.49Da (b) and (d) shall be used to determine the concentrations of SO$_2$ and CO$_2$ or O$_2$.

(d) The owner or operator shall determine compliance with the NO$_X$ standard in Sec. 60.44Da as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NO$_X$.

(2) The continuous monitoring system in Sec. 60.49Da (c) and (d) shall be used to determine the concentrations of NO$_X$ and CO$_2$ or O$_2$.

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

(1) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160°C (320°F). The procedures of Sec. 2.1 and Sec. 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The F$_C$ factor (CO$_2$) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of Sec. 60.48(d)(1). The CO$_2$ shall be determined in the same manner as the O$_2$ concentration.

(f), (g), (h), and (i) {Not applicable.}

§ 60.51Da Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, particulate matter, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) {Not applicable.}

(4) Identification of the boiler operating days for which pollutant or dilutent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO$_2$ only), emergency conditions (SO$_2$ only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.
(c) If the minimum quantity of emission data as required by Sec. 60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of Sec. 60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates \( n_o \) and inlet emission rates \( n_i \).
(2) The standard deviation of hourly averages for outlet emission rates \( s_o \) and inlet emission rates \( s_i \) as applicable.
(3) The lower confidence limit for the mean outlet emission rate \( E_o^* \) and the upper confidence limit for the mean inlet mission rate \( E_i^* \) as applicable.
(4) The applicable potential combustion concentration.
(5) The ratio of the upper confidence limit for the mean outlet emission rate \( E_o^* \) and the allowable emission rate \( E_{std} \) as applicable.

(d) and (e) \( \text{Not applicable.} \)

(f) For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) \( \text{Not applicable.} \)

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.
(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.
(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.
(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under Sec. 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under Sec. 60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A of this part to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for \( \text{SO}_2 \) and/or \( \text{NO}_x \) and/or opacity and/or \( \text{Hg} \) in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

§ 60.52Da Recordkeeping requirements.
The owner or operator of an affected facility subject to the emissions limitations in Sec. 60.45Da or Sec. 60.46Da shall provide notifications in accordance with Sec. 60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of Sec. 60.7(f).
NEW SOURCE PERFORMANCE STANDARDS

Cogeneration Boilers (EUs 001, 002 and 003)

In accordance with Rule 62-204.800(8), F.A.C., the cogeneration boilers are subject to the applicability 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. For these requirements, the original rule numbering has been retained.

(Permitting Note: The cogeneration boilers are subject to regulation as Electric Utility Steam Generating Units in accordance with NSPS Subpart Da. The units fire primarily bagasse and wood materials. Permit conditions in Section 3 limit the units to no more than 30% by weight yard waste (yard trash) on a calendar quarter basis, which can be defined as a municipal solid waste (MSW) in 40 CFR 60.51a. As such, the units are not subject to any specific emissions standards or performance requirements imposed by NSPS Subpart Ea.)

§ 60.50a Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each municipal waste combustor unit with a municipal waste combustor unit capacity greater than 225 megagrams per day (250 tons per day) of municipal solid waste for which construction, modification, or reconstruction is commenced as specified in paragraphs (a)(1) and (a)(2) of this section.

(1) Construction is commenced after December 20, 1989 and on or before September 20, 1994.

(2) Modification or reconstruction is commenced after December 20, 1989 and on or before June 19, 1996.

(b) [Reserved]

(c) [Not applicable.]

(d) Any cofired combustor, as defined under § 60.51a, located at a plant that meets the capacity specifications in paragraph (a) of this section is not subject to this subpart if the owner or operator of the cofired combustor:

(1) Notifies the Administrator of an exemption claim;

(2) Provides a copy of the federally enforceable permit (specified in the definition of cofired combustor in this section); and

(3) Keeps a record on a calendar quarter basis of the weight of municipal solid waste combusted at the cofired combustor and the weight of all other fuels combusted at the cofired combustor.

(e) Any cofired combustor that is subject to a federally enforceable permit limiting the operation of the combustor to no more than 225 megagrams per day (250 tons per day) of municipal solid waste is not subject to this subpart.

(f) [Not applicable.]

(g) A qualifying small power production facility, as defined in section 3(17)(C) of the Federal Power Act (16 U.S.C. 796(17)(C)), that burns homogeneous waste (such as automotive tires or used oil, but not including refuse-derived fuel) for the production of electric energy is not subject to this subpart if the owner or operator of the facility notifies the Administrator of an exemption claim and provides data documenting that the facility qualifies for this exemption.

(h) A qualifying cogeneration facility, as defined in section 3(18)(B) of the Federal Power Act (16 U.S.C. 796(18)(B)), that burns homogeneous waste (such as automotive tires or used oil, but not including refuse-derived fuel) for the production of electric energy and steam or forms of useful energy (such as heat) that
are used for industrial, commercial, heating, or cooling purposes, is not subject to this subpart if the owner or operator of the facility notifies the Administrator of an exemption claim and provides data documenting that the facility qualifies for this exemption.

(i) through (k) \textit{Not applicable.}

(l) The following authorities shall be retained by the Administrator and not transferred to a State: None.

(m) This subpart shall become effective on August 12, 1991.

\textbf{§ 60.51a Definitions.}

\textit{Calendar quarter} means a consecutive 3-month period (non-overlapping) beginning on January 1, April 1, July 1, and October 1.

\textit{Clean wood} means untreated wood or untreated wood products including clean untreated lumber, tree stumps (whole or chipped), and tree limbs (whole or chipped). Clean wood does not include yard waste, which is defined elsewhere in this section, or construction, renovation, and demolition wastes (which includes but is not limited to railroad ties and telephone poles), which are exempt from the definition of municipal solid waste in this section.

\textit{Cofired combustor} means a unit combusting municipal solid waste with non-municipal solid waste fuel (e.g., coal, industrial process waste) and subject to a federally enforceable permit limiting the unit to combusting a fuel feed stream, 30 percent or less of the weight of which is comprised, in aggregate, of municipal solid waste as measured on a calendar quarter basis.

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

\textit{Municipal solid waste} or \textit{municipal-type solid waste} or \textit{MSW} means household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, non-manufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, non-medical waste discarded by hospitals, material discarded by non-manufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional waste does not include used oil; sewage sludge; wood pallets; construction, renovation, and demolition wastes (which includes but is not limited to railroad ties and telephone poles); clean wood; industrial process or manufacturing wastes; medical waste; or motor vehicles (including motor vehicle parts or vehicle fluff). Household, commercial/retail, and institutional wastes include:

(1) Yard waste;

(2) Refuse-derived fuel; and

(3) Motor vehicle maintenance materials limited to vehicle batteries and tires except as specified in § 60.50a(c).

\textit{Untreated lumber} means wood or wood products that have been cut or shaped and include wet, air-dried, and kiln-dried wood products. Untreated lumber does not include wood products that have been painted, pigment-stained, or “pressure-treated.” Pressure-treating compounds include, but are not limited to, chromate copper arsenate, pentachlorophenol, and creosote.

\textit{Yard waste} means grass, grass clippings, bushes, shrubs, and clippings from bushes and shrubs that are generated by residential, commercial/retail, institutional, and/or industrial sources as part of maintenance
activities associated with yards or other private or public lands. Yard waste does not include construction, renovation, and demolition wastes, which are exempt from the definition of MSW in this section. Yard waste does not include clean wood, which is exempt from the definition of MSW in this section.
Subpart DDDD—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

What This Subpart Covers

§ 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limits and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits and work practice standards.

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP as defined in §63.2 or §63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in §63.7491.

§ 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, or existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory located at a major source as defined in §63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source as defined in §63.7575.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after January 13, 2003, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in §63.2, you commence reconstruction after January 13, 2003, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.
§ 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (o) of this section are not subject to this subpart.

(a) A municipal waste combustor covered by 40 CFR part 60, subpart AAAA, subpart BBBBB, subpart Cb or subpart Eb.

(b) A hospital/medical/infectious waste incinerator covered by 40 CFR part 60, subpart Ce or subpart Ec.

(c) An electric utility steam generating unit (including a unit covered by 40 CFR part 60, subpart Da) or a Mercury (Hg) Budget unit covered by 40 CFR part 60, subpart HHHH.

(d) A boiler or process heater required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by 40 CFR part 63, subpart EEE (e.g., hazardous waste boilers).

(e) A commercial and industrial solid waste incineration unit covered by 40 CFR part 60, subpart CCCCC or subpart DDDDD.

(f) A recovery boiler or furnace covered by 40 CFR part 63, subpart MM.

(g) A boiler or process heater that is used specifically for research and development. This does not include units that only provide heat or steam to a process at a research and development facility.

(h) A hot water heater as defined in this subpart.

(i) A refining kettle covered by 40 CFR part 63, subpart X.

(j) An ethylene cracking furnace covered by 40 CFR part 63, subpart YY.


(l) Any boiler and process heater specifically listed as an affected source in another standard(s) under 40 CFR part 63.

(m) Any boiler and process heater specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act (CAA).

(n) Temporary boilers as defined in this subpart.

(o) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.


§ 63.7495 When do I have to comply with this subpart?
(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by November 12, 2004 or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than September 13, 2007.

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing facility must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing facility must be in compliance with this subpart within 3 years after the facility becomes a major source.

(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

**Emission Limits and Work Practice Standards**

§ 63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters are large solid fuel, limited use solid fuel, small solid fuel, large liquid fuel, limited use liquid fuel, small liquid fuel, large gaseous fuel, limited use gaseous fuel, and small gaseous fuel. Each subcategory is defined in §63.7575.

§ 63.7500 What emission limits, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section.

(1) You must meet each emission limit and work practice standard in Table 1 to this subpart that applies to your boiler or process heater, except as provided under §63.7507.

(2) You must meet each operating limit in Tables 2 through 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Tables 2 through 4 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under §63.8(f).

(b) As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

**General Compliance Requirements**

§ 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits (including operating limits) and the work practice
standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

(b) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in §63.6(e)(1)(i).

(c) You can demonstrate compliance with any applicable emission limit using fuel analysis if the emission rate calculated according to §63.7530(d) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using performance testing.

(d) If you demonstrate compliance with any applicable emission limit through performance testing, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under §63.8(f).

(1) For each continuous monitoring system (CMS) required in this section, you must develop and submit to the EPA Administrator for approval a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan at least 60 days before your initial performance evaluation of your CMS.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(e) If you have an applicable emission limit or work practice standard, you must develop a written startup,
shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3).


§ 63.7506 Do any boilers or process heaters have limited requirements?

(a) New or reconstructed boilers and process heaters in the large liquid fuel subcategory or the limited use liquid fuel subcategory that burn only fossil fuels and other gases and do not burn any residual oil are subject to the emission limits and applicable work practice standards in Table 1 to this subpart. You are not required to conduct a performance test to demonstrate compliance with the emission limits. You are not required to set and maintain operating limits to demonstrate continuous compliance with the emission limits. However, you must meet the requirements in paragraphs (a)(1) and (2) of this section and meet the CO work practice standard in Table 1 to this subpart.

(1) To demonstrate initial compliance, you must include a signed statement in the Notification of Compliance Status report required in §63.7545(e) that indicates you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels.

(2) To demonstrate continuous compliance with the applicable emission limits, you must also keep records that demonstrate that you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels. You must also include a signed statement in each semiannual compliance report required in §63.7550 that indicates you burned only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels, during the reporting period.

(b) The affected boilers and process heaters listed in paragraphs (b)(1) through (3) of this section are subject to only the initial notification requirements in §63.9(b) (i.e., they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSMP, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart or any other requirements in subpart A of this part).

(1) Existing large and limited use gaseous fuel units.

(2) Existing large and limited use liquid fuel units.

(3) New or reconstructed small liquid fuel units that burn only gaseous fuels or distillate oil. New or reconstructed small liquid fuel boilers and process heaters that commence burning of any other type of liquid fuel must comply with all applicable requirements of this subpart and subpart A of this part upon startup of burning the other type of liquid fuel.

(c) The affected boilers and process heaters listed in paragraphs (c)(1) through (4) of this section are not subject to the initial notification requirements in §63.9(b) and are not subject to any requirements in this subpart or in subpart A of this part (i.e., they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSMP plans, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart, or any other requirements in subpart A of this part).

(1) Existing small solid fuel boilers and process heaters.
(2) Existing small liquid fuel boilers and process heaters.

(3) Existing small gaseous fuel boilers and process heaters.

(4) New or reconstructed small gaseous fuel units.

§ 63.7507 What are the health-based compliance alternatives for the hydrogen chloride (HCl) and total selected metals (TSM) standards?

(a) As an alternative to the requirement to demonstrate compliance with the HCl emission limit in table 1 to this subpart, you may demonstrate eligibility for the health-based compliance alternative for HCl emissions under the procedures prescribed in appendix A to this subpart.

(b) As an alternative to the requirement to demonstrate compliance with the TSM emission limit in table 1 to this subpart based on the sum of emissions for the eight selected metals, you may demonstrate eligibility for the health-based alternative for manganese emissions under the procedures prescribed in appendix A to this subpart and comply with the TSM emission standards in table 1 based on the sum of emissions for seven selected metals (by excluding manganese emissions from the summation of TSM emissions).

[70 FR 76933, Dec. 28, 2005]

Testing, Fuel Analyses, and Initial Compliance Requirements

§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For affected sources that elect to demonstrate compliance with any of the emission limits of this subpart through performance testing, your initial compliance requirements include conducting performance tests according to §63.7520 and Table 5 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart, establishing operating limits according to §63.7530 and Table 7 to this subpart, and conducting CMS performance evaluations according to §63.7525. For affected sources that burn a single type of fuel, you are exempted from the initial compliance requirements of conducting a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart.

(b) For affected sources that elect to demonstrate compliance with the emission limits for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart and establish operating limits according to §63.7530 and Table 8 to this subpart.

(c) For affected sources that have an applicable work practice standard, your initial compliance requirements depend on the subcategory and rated capacity of your boiler or process heater. If your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, your initial compliance demonstration is conducting a performance test for carbon monoxide according to Table 5 to this subpart. If your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, your initial compliance demonstration is conducting a performance evaluation of your continuous emission monitoring system for carbon monoxide according to §63.7525(a).
(d) For existing affected sources, you must demonstrate initial compliance no later than 180 days after the compliance date that is specified for your source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart.

(e) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003 and November 12, 2004, you must demonstrate initial compliance with either the proposed emission limits and work practice standards or the promulgated emission limits and work practice standards no later than 180 days after November 12, 2004 or within 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(f) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003, and November 12, 2004, and you chose to comply with the proposed emission limits and work practice standards when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits and work practice standards within 3 years after November 12, 2004 or within 3 years after startup of the affected source, whichever is later.

(g) If your new or reconstructed affected source commences construction or reconstruction after November 12, 2004, you must demonstrate initial compliance with the promulgated emission limits and work practice standards no later than 180 days after startup of the source.


§ 63.7515 When must I conduct subsequent performance tests or fuel analyses?

(a) You must conduct all applicable performance tests according to §63.7520 on an annual basis, unless you follow the requirements listed in paragraphs (b) through (d) of this section. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (d) of this section.

(b) You can conduct performance tests less often for a given pollutant if your performance tests for the pollutant (particulate matter, HCl, mercury, or TSM) for at least 3 consecutive years show that you comply with the emission limit. In this case, you do not have to conduct a performance test for that pollutant for the next 2 years. You must conduct a performance test during the third year and no more than 36 months after the previous performance test.

(c) If your boiler or process heater continues to meet the emission limit for particulate matter, HCl, mercury, or TSM, you may choose to conduct performance tests for these pollutants every third year, but each such performance test must be conducted no more than 36 months after the previous performance test.

(d) If a performance test shows noncompliance with an emission limit for particulate matter, HCl, mercury, or TSM, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 3-year period show compliance.

(e) If you have an applicable work practice standard for carbon monoxide and your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, you must conduct annual performance tests for carbon monoxide according to §63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.
(f) You must conduct a fuel analysis according to §63.7521 for each type of fuel burned no later than 5 years after the previous fuel analysis for each fuel type. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in §63.7540.

(g) You must report the results of performance tests and fuel analyses within 60 days after the completion of the performance tests or fuel analyses. This report should also verify that the operating limits for your affected source have not changed or provide documentation of revised operating parameters established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests and fuel analyses should include all applicable information required in §63.7550.

§ 63.7520 What performance tests and procedures must I use?

(a) You must conduct all performance tests according to §63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in §63.7(c) if you elect to demonstrate compliance through performance testing.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to §63.7506(a).

(d) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that have the highest content of chlorine, mercury, and total selected metals, and you must demonstrate initial compliance and establish your operating limits based on these tests. These requirements could result in the need to conduct more than one performance test.

(e) You may not conduct performance tests during periods of startup, shutdown, or malfunction.

(f) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(g) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A to part 60 of this chapter to convert the measured particulate matter concentrations, the measured HCl concentrations, the measured TSM concentrations, and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates using F-factors.

§ 63.7521 What fuel analyses and procedures must I use?

(a) You must conduct fuel analyses according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable.

(b) You must develop and submit a site-specific fuel analysis plan to the EPA Administrator for review and
approval according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section.

(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to demonstrate compliance.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each fuel type, the analytical methods, with the expected minimum detection levels, to be used for the measurement of selected total metals, chlorine, or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that will be used.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. Collect all the material (fines and coarse) in the full cross-section. Transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period.

(2) If sampling from a fuel pile or truck, collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, dig into the pile to a depth of 18 inches. Insert a clean flat square shovel into the
hole and withdraw a sample, making sure that large pieces do not fall off during sampling.

(iii) Transfer all samples to a clean plastic bag for further processing.

(d) Prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) Throughly mix and pour the entire composite sample over a clean plastic sheet.

(2) Break sample pieces larger than 3 inches into smaller sizes.

(3) Make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) Separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) Grind the sample in a mill.

(7) Use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) Determine the concentration of pollutants in the fuel (mercury, chlorine, and/or total selected metals) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart.

§ 63.7522 Can I use emission averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of §63.7500, if you have more than one existing large solid fuel boiler located at your facility, you may demonstrate compliance by emission averaging according to the procedures in this section in a State that does not choose to exclude emission averaging.

(b) Separate stack requirements. For a group of two or more existing large solid fuel boilers that each vent to a separate stack, you may average particulate matter or TSM, HCl and mercury emissions to demonstrate compliance with the limits in Table 1 to this subpart if you satisfy the requirements in paragraphs (c), (d), (e), (f), and (g) of this section.

(c) For each existing large solid fuel boiler in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on November 12, 2004 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on November 12, 2004.

(d) The emissions rate from the existing large solid fuel boilers participating in the emissions averaging option must be in compliance with the limits in Table 1 to this subpart at all times following the compliance date specified in §63.7495.
(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section.

(1) You must use Equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.

\[
\text{Ave Weighted Emissions} = \frac{\sum_{i=1}^{n} (Er \times Hm)}{\sum_{i=1}^{n} Hm} \quad (E\ q\ 1)
\]

Where:

\(\text{Ave Weighted Emissions} = \text{Average weighted emissions for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.}\)

\(\text{Er} = \text{Emission rate (as calculated according to Table 5 to this subpart or by fuel analysis (as calculated by the applicable equation in §63.7530(d))) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.}\)

\(\text{Hm} = \text{Maximum rated heat input capacity of boiler, i, in units of million Btu per hour.}\)

\(n = \text{Number of large solid fuel boilers participating in the emissions averaging option.}\)

(2) If you are not capable of monitoring heat input, you may use Equation 2 of this section as an alternative to using Equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.

\[
\text{Ave Weighted Emissions} = \frac{\sum_{i=1}^{n} (Er \times Sm \times Cf)}{\sum_{i=1}^{n} Sm \times Cf} \quad (E\ q\ 2)
\]

Where:

\(\text{Ave Weighted Emissions} = \text{Average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.}\)

\(\text{Er} = \text{Emission rate (as calculated according to Table 5 to this subpart or by fuel analysis (as calculated by the applicable equation in §63.7530(d))) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.}\)

\(\text{Sm} = \text{Maximum steam generation by boiler, i, in units of pounds.}\)

\(\text{Cf} = \text{Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated.}\)

(f) You must demonstrate continuous compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in §63.7495.

(1) For each calendar month, you must use Equation 3 of this section to calculate the monthly average
weighted emission rate using the actual heat capacity for each existing large solid fuel boiler participating in the emissions averaging option.

\[
\text{Ave Weighted Emissions} = \frac{\sum_{i=1}^{n} (Er \times Hb)}{\sum_{i=1}^{n} Hb} \quad (\text{Eq. 3})
\]

Where:

\(\text{Ave Weighted Emissions}\) = monthly average weighted emission level for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

\(Er =\) Emission rate, (as calculated during the most recent compliance test, (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in §63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

\(Hb =\) The average heat input for each calendar month of boiler, i, in units of million Btu.

\(n =\) Number of large solid fuel boilers participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3 of this section to calculate the monthly weighted emission rate using the actual steam generation from the large solid fuel boilers participating in the emissions averaging option.

\[
\text{Ave Weighted Emissions} = \frac{\sum_{i=1}^{n} (Er \times Sa \times Cf)}{\sum_{i=1}^{n} Sa \times Cf} \quad (\text{Eq. 4})
\]

Where:

\(\text{Ave Weighted Emissions}\) = monthly average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

\(Er =\) Emission rate, (as calculated during the most recent compliance test (as calculated according to Table 5 to this subpart) or by fuel analysis (as calculated by the applicable equation in §63.7530(d))) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

\(Sa =\) Actual steam generation for each calendar month by boiler, i, in units of pounds.

\(Cf =\) Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the monthly average weighted emission rate determined under paragraph (f)(1) or (2) of this section. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 4A of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current month and the previous 11 months.
\[
E_{avg} = \frac{\sum_{i=1}^{12} ER_i}{12} \quad (\text{Eq. 4A})
\]

Where:

\( E_{avg} \) = 12-month rolling average emission rate, (pounds per million Btu heat input)

\( ER_i \) = Monthly weighted average, for month “i”, (pounds per million Btu heat input) (as calculated by (f)(1) or (2))

(g) You must develop and submit an implementation plan for emission averaging to the applicable regulatory authority for review and approval according to the following procedures and requirements in paragraphs (g)(1) through (4).

(1) You must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing large solid fuel boilers in the averaging group, including for each either the applicable HAP emission level or the control technology installed on;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group of large solid fuel boilers;

(iii) The specific control technology or pollution prevention measure to be used for each emission source in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple sources, the owner or operator must identify each source;

(iv) The test plan for the measurement of particulate matter (or TSM), HCl, or mercury emissions in accordance with the requirements in §63.7520;

(v) The operating parameters to be monitored for each control system or device and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to §63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the applicable regulatory authority, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and
(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating conditions.

(3) Upon receipt, the regulatory authority shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable regulatory authority shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing large solid fuel boiler.

(h) Common stack requirements. For a group of two or more existing large solid fuel boilers, each of which vents through a single common stack, you may average particulate matter or TSM, HCl and mercury to demonstrate compliance with the limits in Table 1 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing large solid fuel boilers, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing solid fuel boiler for purposes of this subpart and comply with the requirements of this subpart as if the group were a single boiler.

(j) For all other groups of boilers subject to paragraph (h) of this section, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in §63.7520 in the common stack (if affected units from other subcategories (e.g., gas-fired units) or nonaffected units vent to the common stack, the units from other subcategories and nonaffected units must be shut down or vented to a different stack during the performance test); and

(2) Meet the applicable operating limit specified in §63.7540 and Table 8 to this subpart for each emissions control system (except that, if each boiler venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) Combination requirements. The common stack of a group of two or more boilers subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.
§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If you have an applicable work practice standard for carbon monoxide, and your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, you must install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide and oxygen according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in §63.7495. The carbon monoxide and oxygen shall be monitored at the same location at the outlet of the boiler or process heater.

(1) Each CEMS must be installed, operated, and maintained according to the applicable procedures under Performance Specification (PS) 3 or 4A of 40 CFR part 60, appendix B, and according to the site-specific monitoring plan developed according to §63.7505(d).

(2) You must conduct a performance evaluation of each CEMS according to the requirements in §63.8 and according to PS 4A of 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) The CEMS data must be reduced as specified in §63.8(g)(2).

(5) You must calculate and record a 30-day rolling average emission rate on a daily basis. A new 30-day rolling average emission rate is calculated as the average of all of the hourly CO emission data for the preceding 30 operating days.

(6) For purposes of calculating data averages, you must not use data recorded during periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when your boiler or process heater is operating at less than 50 percent of its rated capacity. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(b) If you have an applicable opacity operating limit, you must install, operate, certify and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (b)(1) through (7) of this section by the compliance date specified in §63.7495.

(1) Each COMS must be installed, operated, and maintained according to PS 1 of 40 CFR part 60, appendix B.

(2) You must conduct a performance evaluation of each COMS according to the requirements in §63.8 and according to PS 1 of 40 CFR part 60, appendix B.

(3) As specified in §63.8(c)(4)(i), each COMS must 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.
(4) The COMS data must be reduced as specified in §63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in §63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of §63.8(e). Identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.

(7) You must determine and record all the 6-minute averages (and 1-hour block averages as applicable) collected for periods during which the COMS is not out of control.

(c) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (c)(1) through (5) of this section by the compliance date specified in §63.7495.

(1) The CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation at all times that the unit is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(3) For purposes of calculating data averages, you must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(4) Determine the 3-hour block average of all recorded readings, except as provided in paragraph (c)(3) of this section.

(5) Record the results of each inspection, calibration, and validation check.

(d) If you have an operating limit that requires the use of a flow measurement device, you must meet the requirements in paragraphs (c) and (d)(1) through (4) of this section.

(1) Locate the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) Use a flow sensor with a measurement sensitivity of 2 percent of the flow rate.
(3) Reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) Conduct a flow sensor calibration check at least semiannually.

(e) If you have an operating limit that requires the use of a pressure measurement device, you must meet the requirements in paragraphs (c) and (e)(1) through (6) of this section.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure.

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.

(3) Use a gauge with a minimum tolerance of 1.27 centimeters of water or a transducer with a minimum tolerance of 1 percent of the pressure range.

(4) Check pressure tap pluggage daily.

(5) Using a manometer, check gauge calibration quarterly and transducer calibration monthly.

(6) Conduct calibration checks any time the sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(f) If you have an operating limit that requires the use of a pH measurement device, you must meet the requirements in paragraphs (c) and (f)(1) through (3) of this section.

(1) Locate the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Check the pH meter's calibration on at least two points every 8 hours of process operation.

(g) If you have an operating limit that requires the use of equipment to monitor voltage and secondary current (or total power input) of an electrostatic precipitator (ESP), you must use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP.

(h) If you have an operating limit that requires the use of equipment to monitor sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (c) and (h)(1) through (3) of this section.

(1) Locate the device in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Install and calibrate the device in accordance with manufacturer's procedures and specifications.

(3) At least annually, calibrate the device in accordance with the manufacturer's procedures and specifications.
(i) If you elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate a bag leak detection system as specified in paragraphs (i)(1) through (8) of this section.

(1) You must install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA–454/R–98–015, September 1997.

(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(6) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.

(7) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(8) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.


§ 63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?

(a) You must demonstrate initial compliance with each emission limit and work practice standard that applies to you by either conducting initial performance tests and establishing operating limits, as applicable, according to §63.7520, paragraph (c) of this section, and Tables 5 and 7 to this subpart OR conducting initial fuel analyses to determine emission rates and establishing operating limits, as applicable, according to §63.7521, paragraph (d) of this section, and Tables 6 and 8 to this subpart.

(b) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to §63.7506(a).

(c) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Tables 2 through 4 to this subpart that applies to you according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (c)(4) of this section, as applicable. You must also conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according
to paragraphs (c)(1) through (3) of this section, as applicable.

(1) You must establish the maximum chlorine fuel input \( (C_{input}) \) during the initial performance testing according to the procedures in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the performance testing for HCl, you must determine the fraction of the total heat input for each fuel type burned \( (Q_i) \) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned \( (C_i) \).

(iii) You must establish a maximum chlorine input level using Equation 5 of this section.

\[
Cl_{input} = \sum_{i=1}^{n}[(C_i)(Q_i)] \quad (Eq. 5)
\]

Where:

\( Cl_{input} \) = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

\( C_i \) = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

\( Q_i \) = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for \( Q_i \).

\( n \) = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) If you choose to comply with the alternative TSM emission limit instead of the particulate matter emission limit, you must establish the maximum TSM fuel input level \( (TSM_{input}) \) during the initial performance testing according to the procedures in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the performance testing for TSM, you must determine the fraction of total heat input from each fuel burned \( (Q_i) \) based on the fuel mixture that has the highest content of total selected metals, and the average TSM concentration of each fuel type burned \( (M_i) \).

(iii) You must establish a baseline TSM input level using Equation 6 of this section.

\[
TSM_{input} = \sum_{i=1}^{n}[(M_i)(Q_i)] \quad (Eq. 6)
\]
Where:

\[ TSM_{\text{input}} = \text{Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.} \]

\[ M_i = \text{Arithmetic average concentration of TSM in fuel type, } i, \text{ analyzed according to } \S 63.7521, \text{ in units of pounds per million Btu.} \]

\[ Q_i = \text{Fraction of total heat input from based fuel type, } i, \text{ based on the fuel mixture that has the highest content of TSM. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for } Q_i. \]

\[ n = \text{Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.} \]

(3) You must establish the maximum mercury fuel input level (Mercury_{\text{input}}) during the initial performance testing using the procedures in paragraphs (c)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (\( Q_i \)) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (\( HG_i \)).

(iii) You must establish a maximum mercury input level using Equation 7 of this section.

\[ \text{Mercury}_{\text{input}} = \sum_{i=1}^{n} \left[ (HG_i)(Q_i) \right] \quad (\text{Eq. 7}) \]

Where:

\[ \text{Mercury}_{\text{input}} = \text{Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.} \]

\[ HG_i = \text{Arithmetic average concentration of mercury in fuel type, } i, \text{ analyzed according to } \S 63.7521, \text{ in units of pounds per million Btu.} \]

\[ Q_i = \text{Fraction of total heat input from fuel type, } i, \text{ based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for } Q_i. \]

\[ n = \text{Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.} \]

(4) You must establish parameter operating limits according to paragraphs (c)(4)(i) through (iv) of this section.

(i) For a wet scrubber, you must establish the minimum scrubber effluent pH, liquid flowrate, and pressure
drop as defined in §63.7575, as your operating limits during the three-run performance test. If you use a wet scrubber and you conduct separate performance tests for particulate matter, HCl, and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flowrate and pressure drop operating limits at the highest minimum values established during the performance tests.

(ii) For an electrostatic precipitator, you must establish the minimum voltage and secondary current (or total power input), as defined in §63.7575, as your operating limits during the three-run performance test.

(iii) For a dry scrubber, you must establish the minimum sorbent injection rate, as defined in §63.7575, as your operating limit during the three-run performance test.

(iv) The operating limit for boilers or process heaters with fabric filters that choose to demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in §63.7525, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.

(d) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to §63.7521 and follow the procedures in paragraphs (d)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided z-statistic test described in Equation 8 of this section.

\[ P_{90} = \text{mean} + (SD \times t) \quad (\text{Eq. 8}) \]

Where:

\( P_{90} \) = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

\( \text{mean} \) = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu.

\( SD \) = Standard deviation of the pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu.

\( t \) = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 9 of this section must be less than the
applicable emission limit for HCl.

\[ HCl = \sum_{i=1}^{n} \left[ (C_{90i}) (Q_i) (1.028) \right] \quad (Eq. 9) \]

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

\( C_{90i} \) = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

\( Q_i \) = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for \( Q_i \).

\( n \) = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for TSM, the TSM emission rate that you calculate for your boiler or process heater using Equation 10 of this section must be less than the applicable emission limit for TSM.

\[ TSM = \sum_{i=1}^{n} \left[ (M_{90i}) (Q_i) \right] \quad (Eq. 10) \]

Where:

TSM = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

\( M_{90i} \) = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

\( Q_i \) = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of total selected metals. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for \( Q_i \).

\( n \) = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(5) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 11 of this section must be less than the applicable emission limit for mercury.

\[ Mercury = \sum_{i=1}^{n} \left[ (HC_{90i}) (Q_i) \right] \quad (Eq. 11) \]
Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

\( \text{HG}_{90} \) = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

\( Q_i \) = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of \( "1" \) for \( Q_i \).

\( n \) = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(e) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e).

Continuous Compliance Requirements

§ 63.7535 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.7505(d).

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, or required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system. Boilers and process heaters that have an applicable carbon monoxide work practice standard and are required to install and operate a CEMS, may not use data recorded during periods when the boiler or process heater is operating at less than 50 percent of its rated capacity.

§ 63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (10) of this section.

(1) Following the date on which the initial performance test is completed or is required to be completed under §§63.7 and 63.7510, whichever date comes first, you must not operate above any of the applicable maximum operating limits or below any of the applicable minimum operating limits listed in Tables 2 through 4 to this subpart at all times except during periods of startup, shutdown and malfunction. Operating limits do not apply during performance tests. Operation above the established maximum or
below the established minimum operating limits shall constitute a deviation of established operating limits.

(2) You must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would either result in lower emissions of TSM, HCl, and mercury, than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis), or result in lower fuel input of TSM, chlorine, and mercury than the maximum values calculated during the last performance tests (if you demonstrate compliance through performance testing).

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis and you plan to burn a new type of fuel, you must recalculate the HCl emission rate using Equation 9 of §63.7530 according to paragraphs (a)(3)(i) through (iii) of this section.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 9 of §63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 5 of §63.7530. If the results of recalculating the maximum chlorine input using Equation 5 of §63.7530 are higher than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(c).

(5) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 10 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 10 of §63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM
input using Equation 6 of §63.7530. If the results of recalculating the maximum total selected metals input using Equation 6 of §63.7530 are higher than the maximum TSM input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(c).

(7) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 11 of §63.7530 according to the procedures specified in paragraphs (a)(7)(i) through (iii) of this section.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 11 of §63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(8) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 7 of §63.7530. If the results of recalculating the maximum mercury input using Equation 7 of §63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(c).

(9) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.

(10) If you have an applicable work practice standard for carbon monoxide, and you are required to install a CEMS according to §63.7525(a), then you must meet the requirements in paragraphs (a)(10)(i) through (iii) of this section.

(i) You must continuously monitor carbon monoxide according to §§63.7525(a) and 63.7535.

(ii) Maintain a carbon monoxide emission level below your applicable carbon monoxide work practice
standard in Table 1 to this subpart at all times except during periods of startup, shutdown, malfunction, and when your boiler or process heater is operating at less than 50 percent of rated capacity.

(iii) Keep records of carbon monoxide levels according to §63.7555(b).

(b) You must report each instance in which you did not meet each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that apply to you. You must also report each instance during a startup, shutdown, or malfunction when you did not meet each applicable emission limit, operating limit, and work practice standard. These instances are deviations from the emission limits and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) [Reserved]

(d) Consistent with §§63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the EPA Administrator's satisfaction that you were operating in accordance with §63.6(e)(1). The EPA Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).


§ 63.7541 How do I demonstrate continuous compliance under the emission averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing large solid fuel boilers participating in the emissions averaging option as determined in §63.7522(f) and (g);

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) through (ii) of this section.

(i) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of boilers participating in the emissions averaging option where each boiler in the group is an existing solid fuel boiler equipped with a dry control system and vented to a common stack that does not receive emissions from affected units from other subcategories or nonaffected units, maintain opacity at or below the applicable limit at the common stack;

(3) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test; and

(4) For each existing solid fuel boiler participating in the emissions averaging option that has an approved alternative operating plan, maintain the 3-hour average parameter values at or below the operating limits
established in the most recent performance test.

(5) For each existing large solid fuel boiler participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories and/or nonaffected units, maintain the appropriate operating limit for each unit as specified in Tables 2 through 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section, except during periods of startup, shutdown, and malfunction, is a deviation.


Notification, Reports, and Records

§ 63.7545 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you startup your affected source before November 12, 2004, you must submit an Initial Notification not later than 120 days after November 12, 2004. The Initial Notification must include the information required in paragraphs (b)(1) and (2) of this section, as applicable.

(1) If your affected source has an annual capacity factor of greater than 10 percent, your Initial Notification must include the information required by §63.9(b)(2).

(2) If your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories (the limited use solid fuel subcategory, the limited use liquid fuel subcategory, or the limited use gaseous fuel subcategory), your Initial Notification must include the information required by §63.9(b)(2) and also a signed statement indicating your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent.

(c) As specified in §63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after November 12, 2004, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530(a), you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For each initial compliance demonstration, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1)
through (9), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the capacity of the source, a description of the add-on controls used on the source description of the fuel(s) burned, and justification for the fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests, fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you are complying with the particulate matter emission limit or the alternative total selected metals emission limit.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging.

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) A summary of the carbon monoxide emissions monitoring data and the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable work practice standard in Table 1 to this subpart.

(8) If your new or reconstructed boiler or process heater is in one of the liquid fuel subcategories and burns only liquid fossil fuels other than residual oil either alone or in combination with gaseous fuels, you must submit a signed statement certifying this in your Notification of Compliance Status report.

(9) If you had a deviation from any emission limit or work practice standard, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

§ 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.7495.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.7495.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1
through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (11) of this section.

(1) Company name and address.

(2) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel and the total fuel usage amount with units of measure.

(5) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.

(6) A signed statement indicating that you burned no new types of fuel. Or, if you did burn a new type of fuel, you must submit the calculation of chlorine input, using Equation 5 of §63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 9 of §63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of TSM input, using Equation 6 of §63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate using Equation 10 of §63.7530 that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of mercury input, using Equation 7 of §63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 11 of §63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(7) If you wish to burn a new type of fuel and you can not demonstrate compliance with the maximum chlorine input operating limit using Equation 5 of §63.7530, the maximum TSM input operating limit using
Equation 6 of §63.7530, or the maximum mercury input operating limit using Equation 7 of §63.7530, you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(8) The hours of operation for each boiler and process heater that is subject to an emission limit for each calendar month within the semiannual reporting period. This requirement applies only to limited use boilers and process heaters.

(9) If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your SSMP, the compliance report must include the information in §63.10(d)(5)(i).

(10) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, and there are no deviations from the requirements for work practice standards in this subpart, a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.

(11) If there were no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out of control during the reporting period.

(d) For each deviation from an emission limit or operating limit in this subpart and for each deviation from the requirements for work practice standards in this subpart that occurs at an affected source where you are not using a CMSs to comply with that emission limit, operating limit, or work practice standard, the compliance report must contain the information in paragraphs (c)(1) through (10) of this section and the information required in paragraphs (d)(1) through (4) of this section. This includes periods of startup, shutdown, and malfunction.

(1) The total operating time of each affected source during the reporting period.

(2) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

(3) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(4) A copy of the test report if the annual performance test showed a deviation from the emission limit for particulate matter or the alternative TSM limit, a deviation from the HCl emission limit, or a deviation from the mercury emission limit.

(e) For each deviation from an emission limitation and operating limit or work practice standard in this subpart occurring at an affected source where you are using a CMS to comply with that emission limit, operating limit, or work practice standard, you must include the information in paragraphs (c)(1) through (10) of this section and the information required in paragraphs (e)(1) through (12) of this section. This includes periods of startup, shutdown, and malfunction and any deviations from your site-specific monitoring plan as required in §63.7505(d).

(1) The date and time that each malfunction started and stopped and description of the nature of the
deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMSs downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) An identification of each parameter that was monitored at the affected source for which there was a deviation, including opacity, carbon monoxide, and operating parameters for wet scrubbers and other control devices.

(9) A brief description of the source for which there was a deviation.

(10) A brief description of each CMS for which there was a deviation.

(11) The date of the latest CMS certification or audit for the system for which there was a deviation.

(12) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 9 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you operate a new gaseous fuel unit that is subject to the work practice standard specified in Table 1 to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the
information specified in paragraphs (g)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

§ 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) through (3) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests, fuel analyses, or other compliance demonstrations, performance evaluations, and opacity observations as required in §63.10(b)(2)(viii).

(b) For each CEMS, CPMS, and COMS, you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2) (vi) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in §63.6(h)(7)(i) and (ii).

(3) Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits such as opacity, pressure drop, carbon monoxide, and pH to show continuous compliance with each emission limit, operating limit, and work practice standard that applies to you.

(d) For each boiler or process heater subject to an emission limit, you must also keep the records in
paragraphs (d)(1) through (5) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) You must keep records of monthly hours of operation by each boiler or process heater. This requirement applies only to limited-use boilers and process heaters.

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 5 of §63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 9 of §63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(4) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 6 of §63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 10 of §63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 7 of §63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 11 of §63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(e) If your boiler or process heater is subject to an emission limit or work practice standard in Table 1 to this subpart and has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories, you must keep the records in paragraphs (e)(1) and (2) of this section.

(1) A copy of the federally enforceable permit that limits the annual capacity factor of the source to less than or equal to 10 percent.

(2) Fuel use records for the days the boiler or process heater was operating.
§ 63.7560 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§ 63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency, however, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in §63.7500(a) and (b) under §63.6(g).

(2) Approval of alternative opacity emission limits in §63.7500(a) under §63.6(h)(9).

(3) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(4) Approval of major change to monitoring under §63.8(f) and as defined in §63.90.

(5) Approval of major change to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

§ 63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in §63.2 (the General Provisions), and in this section.
as follows:

**Annual capacity factor** means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year, and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

**Bag leak detection system** means an instrument that is capable of monitoring particulate matter loadings in the exhaust of a fabric filter (i.e., baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

**Biomass fuel** means unadulterated wood as defined in this subpart, wood residue, and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sanderdust, chips, scraps, slabs, millings, and shavings); animal litter; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds.

**Blast furnace gas fuel-fired boiler or process heater** means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total heat input (based on an annual average) from blast furnace gas.

**Boiler** means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from this definition.

**Coal** means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388–991, “Standard Specification for Classification of Coals by Rank” (incorporated by reference, see §63.14(b)), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures, for the purposes of this subpart. Coal derived gases are excluded from this definition.

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

**Commercial/institutional boiler** means a boiler used in commercial establishments or institutional establishments such as medical centers, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water.

**Common Stack** means the exhaust of emissions from two or more affected units through a single flue.

**Construction/demolition material** means waste building material that result from the construction or demolition operations on houses and commercial and industrial buildings.

**Deviation.** (1) Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:
(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(iii) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless or whether or not such failure is permitted by this subpart.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

*Distillate oil* means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D396–02a, “Standard Specifications for Fuel Oils” (incorporated by reference, see §63.14(b)).

*Dry scrubber* means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems in fluidized bed boilers and process heaters are included in this definition.

*Electric utility steam generating unit* means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.

*Electrostatic precipitator* means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

*Equivalent* means the following only as this term is used in Table 6 to subpart DDDDD:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to
obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an “as received” basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, TSM, or total chlorine) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to subpart DDDDD for the same purpose.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse.

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

Firetube boiler means a boiler that utilizes a containment shell that encloses firetubes (tubes in a boiler having water on the outside and carrying the hot gases of combustion inside), and allows the water to vaporize and steam to separate. Hybrid boilers that have been registered/certified by the National Board of Boiler and Pressure Vessel Inspectors and/or the State as firetube boilers as indicated by “Form P–2” (Manufacturers' Data Report for All Types of Boilers Except Watertube and Electric, As Required by the Provisions of the ASME Code Rules, Section I), are considered to be firetube boilers for the purpose of this subpart.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, construction/demolition material, salt water laden wood, creosote treated wood, tires, residual oil. Individual fuel types received from different suppliers are not considered new fuel types except for construction/demolition material. Contraband, prohibited goods, or retired U.S. flags, burned at the request of a government agency, are not considered a fuel type for the purpose of this subpart.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas is exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210 °F (99 °C).
**Industrial boiler** means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

**Large gaseous fuel subcategory** includes any watertube boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or for periodic testing of liquid fuel, has a rated capacity of greater than 10 MMBtu per hour heat input, and does not have a federally enforceable annual average capacity factor of equal to or less than 10 percent. Periodic testing of liquid fuel is not to exceed a combined total of 48 hours during any calendar year.

**Large liquid fuel subcategory** includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and does not have a federally enforceable annual average capacity factor of equal to or less than 10 percent. Large gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year are not included in this definition.

**Large solid fuel subcategory** includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and does not have a federally enforceable annual average capacity factor of equal to or less than 10 percent.

**Limited use gaseous fuel subcategory** includes any watertube boiler or process heater that burns gaseous fuels not combined with any liquid or solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

**Limited use liquid fuel subcategory** includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent. Limited use gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

**Limited use solid fuel subcategory** includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

**Liquid fossil fuel** means petroleum, distillate oil, residual oil and any form of liquid fuel derived from such material.

**Liquid fuel** includes, but is not limited to, distillate oil, residual oil, waste oil, and process liquids.

**Minimum pressure drop** means 90 percent of the lowest test-run average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

**Minimum scrubber effluent pH** means 90 percent of the lowest test-run average effluent pH measured at
the outlet of the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

**Minimum scrubber flow rate** means 90 percent of the lowest test-run average flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

**Minimum sorbent flow rate** means 90 percent of the lowest test-run average sorbent (or activated carbon) flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

**Minimum voltage or amperage** means 90 percent of the lowest test-run average voltage or amperage to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

**Natural gas** means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835–03a, “Standard Specification for Liquid Petroleum Gases” (incorporated by reference, see §63.14(b)).

**Opacity** means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

**Particulate matter** means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an alternative method.

**Period of natural gas curtailment or supply interruption** means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.

**Process heater** means an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.

**Residual oil** means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by the American Society for Testing and Materials in ASTM D396–02a, “Standard Specifications for Fuel Oils” (incorporated by reference, see §63.14(b)).

**Responsible official** means responsible official as defined in 40 CFR 70.2.

**Small gaseous fuel subcategory** includes any size of firetube boiler and any other boiler or process heater...
with a rated capacity of less than or equal to 10 MMBtu per hour heat input that burn gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or for periodic testing of liquid fuel. Periodic testing is not to exceed a combined total of 48 hours during any calendar year.

**Small liquid fuel subcategory** includes any size of firetube boiler and any other boiler or process with a rated capacity of less than or equal to 10 MMBtu per hour heat input that do not burn any solid fuel and burn any liquid fuel either alone or in combination with gaseous fuels. Small gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year are not included in this definition.

**Small solid fuel subcategory** includes any firetube boiler that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, and any other boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.

**Solid fuel** includes, but is not limited to, coal, wood, biomass, tires, plastics, and other nonfossil solid materials.

**Temporary boiler** means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period.

**Total selected metals** means the combination of the following metallic HAP: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

**Unadulterated wood** means wood or wood products that have not been painted, pigment-stained, or pressure treated with compounds such as chromate copper arsenate, pentachlorophenol, and creosote. Plywood, particle board, oriented strand board, and other types of wood products bound by glues and resins are included in this definition.

**Voluntary Consensus Standards or VCS** mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. states, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g. Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

**Waste heat boiler** means a device that recovers normally unused energy and converts it to usable heat.
Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators.

*Watertube boiler* means a boiler that incorporates a steam drum with tubes connected to the drum to separate steam from water.

*Wet scrubber* means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter and/or to absorb and neutralize acid gases, such as hydrogen chloride.

*Work practice standard* means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.


**Table 1 to Subpart DDDDD of Part 63—Emission Limits and Work Practice Standards**

As stated in §63.7500, you must comply with the following applicable emission limits and work practice standards:

<table>
<thead>
<tr>
<th>If your boiler or process heater is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>You must meet the following emission limits and work practice standards . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. New or reconstructed large solid fuel</td>
<td>a. Particulate Matter (or Total Selected Metals)</td>
<td>0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).</td>
</tr>
<tr>
<td></td>
<td>b. Hydrogen Chloride</td>
<td>0.02 lb per MMBtu of heat input.</td>
</tr>
<tr>
<td></td>
<td>c. Mercury</td>
<td>0.000003 lb per MMBtu of heat input.</td>
</tr>
<tr>
<td></td>
<td>d. Carbon Monoxide</td>
<td>400 ppm by volume on a dry basis corrected to 7 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).</td>
</tr>
<tr>
<td>2. New or reconstructed limited use solid fuel</td>
<td>a. Particulate Matter (or Total Selected Metals)</td>
<td>0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).</td>
</tr>
<tr>
<td></td>
<td>b. Hydrogen Chloride</td>
<td>0.02 lb per MMBtu of heat input.</td>
</tr>
<tr>
<td></td>
<td>c. Mercury</td>
<td>0.000003 lb per MMBtu of heat input.</td>
</tr>
<tr>
<td>Fuel Type</td>
<td>Pollutant</td>
<td>Emission Limit</td>
</tr>
<tr>
<td>-----------------------------------------------</td>
<td>--------------------------------</td>
<td>-----------------------------------------------------</td>
</tr>
<tr>
<td>3. New or reconstructed small solid fuel</td>
<td>Particulate Matter</td>
<td>0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).</td>
</tr>
<tr>
<td></td>
<td>Chloride</td>
<td>0.02 lb per MMBtu of heat input.</td>
</tr>
<tr>
<td></td>
<td>Mercury</td>
<td>0.000003 lb per MMBtu of heat input.</td>
</tr>
<tr>
<td>4. New reconstructed large liquid fuel</td>
<td>Particulate Matter</td>
<td>0.03 lb per MMBtu of heat input.</td>
</tr>
<tr>
<td></td>
<td>Chloride</td>
<td>0.0005 lb per MMBtu of heat input.</td>
</tr>
<tr>
<td></td>
<td>Carbon Monoxide</td>
<td>400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).</td>
</tr>
<tr>
<td>5. New or reconstructed limited use liquid fuel</td>
<td>Particulate Matter</td>
<td>0.03 lb per MMBtu of heat input.</td>
</tr>
<tr>
<td></td>
<td>Chloride</td>
<td>0.0009 lb per MMBtu of heat input.</td>
</tr>
<tr>
<td></td>
<td>Carbon Monoxide</td>
<td>400 ppm by volume on a dry basis liquid corrected to 3 percent oxygen (3-run average).</td>
</tr>
<tr>
<td>6. New or reconstructed small liquid fuel</td>
<td>Particulate Matter</td>
<td>0.03 lb per MMBtu of heat input.</td>
</tr>
<tr>
<td></td>
<td>Chloride</td>
<td>0.0009 lb per MMBtu of heat input.</td>
</tr>
<tr>
<td>7. New reconstructed large gaseous fuel</td>
<td>Carbon Monoxide</td>
<td>400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).</td>
</tr>
<tr>
<td>8. New or reconstructed limited use gaseous fuel</td>
<td>Carbon Monoxide</td>
<td>400 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average).</td>
</tr>
<tr>
<td>9. Existing large solid fuel</td>
<td>Particulate Matter</td>
<td>0.07 lb per MMBtu of heat input; or (0.001 lb per MMBtu of heat input).</td>
</tr>
<tr>
<td></td>
<td>Chloride</td>
<td>0.09 lb per MMBtu of heat input.</td>
</tr>
<tr>
<td>Chloride</td>
<td>0.000009 lb per MMBtu of heat input.</td>
<td></td>
</tr>
<tr>
<td>----------</td>
<td>-------------------------------------</td>
<td></td>
</tr>
<tr>
<td>Mercury</td>
<td>0.21 lb per MMBtu of heat input; or (0.004 lb per MMBtu of heat input).</td>
<td></td>
</tr>
</tbody>
</table>

10. Existing limited use solid fuel

| Particulate Matter (or Total Selected Metals) | 0.21 lb per MMBtu of heat input; or (0.004 lb per MMBtu of heat input). |

Table 2 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters With Particulate Matter Emission Limits

As stated in §63.7500, you must comply with the applicable operating limits:

<table>
<thead>
<tr>
<th>If you demonstrate compliance with applicable particulate matter emission limits using . . .</th>
<th>You must meet these operating limits . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Wet scrubber control</td>
<td>a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.</td>
</tr>
<tr>
<td>2. Fabric filter control</td>
<td>a. Install and operate a bag leak detection system according to §63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period; or</td>
</tr>
<tr>
<td></td>
<td>b. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).</td>
</tr>
<tr>
<td>3. Electrostatic precipitator control</td>
<td>a. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or</td>
</tr>
<tr>
<td></td>
<td>b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.</td>
</tr>
</tbody>
</table>
4. Any other control type

This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).

Table 3 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters With Mercury Emission Limits and Boilers and Process Heaters That Choose To Comply With the Alternative Total Selected Metals Emission Limits

As stated in §63.7500, you must comply with the applicable operating limits:

<table>
<thead>
<tr>
<th>If you demonstrate compliance with applicable mercury and/or total selected metals emission limits using . . .</th>
<th>You must meet these operating limits . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Wet scrubber control</td>
<td>Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limits for mercury and/or total selected metals.</td>
</tr>
<tr>
<td>2. Fabric filter control</td>
<td>a. Install and operate a bag leak detection system according to §63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period; or</td>
</tr>
<tr>
<td></td>
<td>b. This option is for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).</td>
</tr>
<tr>
<td>3. Electrostatic precipitator control</td>
<td>a. This option is for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or</td>
</tr>
<tr>
<td></td>
<td>b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated</td>
</tr>
</tbody>
</table>
4. Dry scrubber or carbon injection control

Maintain the minimum sorbent or carbon injection rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for mercury.

5. Any other control type

This option is only for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).

6. Fuel analysis

Maintain the fuel type or fuel mixture such that the mercury and/or total selected metals emission rates calculated according to §63.7530(d)(4) and/or (5) is less than the applicable emission limits for mercury and/or total selected metals.

Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters With Hydrogen Chloride Emission Limits

As stated in §63.7500, you must comply with the following applicable operating limits:

<table>
<thead>
<tr>
<th>If you demonstrate compliance with applicable hydrogen chloride emission limits using . . .</th>
<th>You must meet these operating limits . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Wet scrubber control</td>
<td>Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.</td>
</tr>
<tr>
<td>2. Dry scrubber control</td>
<td>Maintain the minimum sorbent injection rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.</td>
</tr>
<tr>
<td>3. Fuel analysis</td>
<td>Maintain the fuel type or fuel mixture such that the hydrogen chloride emission rate calculated according to §63.7530(d)(3) is less than the applicable emission limit for hydrogen chloride.</td>
</tr>
</tbody>
</table>

Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements

As stated in §63.7520, you must comply with the following requirements for performance test for existing,
To conduct a performance test for the following pollutant...

<table>
<thead>
<tr>
<th>To conduct a performance test for the following pollutant . . .</th>
<th>You must . . .</th>
<th>Using . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Particulate Matter</td>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Method 1 in appendix A to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2F, or 2G in appendix A to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>c. Determine oxygen and carbon dioxide concentrations of the stack gas</td>
<td>Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).</td>
</tr>
<tr>
<td></td>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 in appendix A to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>e. Measure the particulate matter emission concentration</td>
<td>Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>f. Convert emissions concentration to lb per MMBtu emission rates</td>
<td>Method 19 F-factor methodology in appendix A to part 60 of this chapter.</td>
</tr>
<tr>
<td>2. Total selected metals</td>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Method 1 in appendix A to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2F, or 2G in appendix A to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>c. Determine oxygen and carbon dioxide concentrations of the stack gas</td>
<td>Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).</td>
</tr>
<tr>
<td></td>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 in appendix A to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>e. Measure the total selected metals emission concentration</td>
<td>Method 29 in appendix A to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td></td>
</tr>
<tr>
<td>f. Convert emissions concentration to lb per MMBtu emission rates</td>
<td>Method 19 F-factor methodology in appendix A to part 60 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>3. Hydrogen chloride</td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Method 1 in appendix A to part 60 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2F, or 2G in appendix A to part 60 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>c. Determine oxygen and carbon dioxide concentrations of the stack gas</td>
<td>Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).</td>
<td></td>
</tr>
<tr>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 in appendix A to part 60 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>e. Measure the hydrogen chloride emission concentration</td>
<td>Method 26 or 26A in appendix A to part 60 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>f. Convert emissions concentration to lb per MMBtu emission rates</td>
<td>Method 19 F-factor methodology in appendix A to part 60 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>4. Mercury</td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Method 1 in appendix A to part 60 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2F, or 2G in appendix A to part 60 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>c. Determine oxygen and carbon dioxide concentrations of the stack gas</td>
<td>Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §62.14(i)).</td>
<td></td>
</tr>
<tr>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 in appendix A to part 60 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>e. Measure the mercury emission concentration</td>
<td>Method 29 in appendix A to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784–02 (IBR, see §63.14(b)).</td>
<td></td>
</tr>
<tr>
<td>f. Convert emissions</td>
<td>Method 19 F-factor methodology in appendix A</td>
<td></td>
</tr>
</tbody>
</table>
concentration to lb per MMBtu emission rates to part 60 of this chapter.

5. Carbon Monoxide

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>a.</td>
<td>Select the sampling ports location and the number of traverse points</td>
</tr>
<tr>
<td></td>
<td>Method 1 in appendix A to part 60 of this chapter.</td>
</tr>
<tr>
<td>b.</td>
<td>Determine oxygen and carbon dioxide concentrations of the stack gas</td>
</tr>
<tr>
<td></td>
<td>Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see §63.14(b)), or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).</td>
</tr>
<tr>
<td>c.</td>
<td>Measure the moisture content of the stack gas</td>
</tr>
<tr>
<td></td>
<td>Method 4 in appendix A to part 60 of this chapter.</td>
</tr>
<tr>
<td>d.</td>
<td>Measure the carbon monoxide emission concentration</td>
</tr>
<tr>
<td></td>
<td>Method 10, 10A, or 10B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see §63.14(b)) when the fuel is natural gas.</td>
</tr>
</tbody>
</table>

Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements

As stated in §63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

<table>
<thead>
<tr>
<th>To conduct a fuel analysis for the following pollutant</th>
<th>You must * * *</th>
<th>Using * * *</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Mercury * * *</td>
<td>a. Collect fuel samples * * *</td>
<td>Procedure in §63.7521(c) or ASTM D2234–D2234M–03 (for coal) (IBR, see §63.14(b)) or ASTM D6323–98 (2003) (for biomass) (IBR, See §63.14(b)) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>b. Composite fuel samples * * *</td>
<td>Procedure in §63.7521(d) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>c. Prepare comitted fuel samples * * *</td>
<td>SW–846–3050B (for solid samples) or SW–846–3020A (for liquid samples) or ASTM D2013–04 (for coal) (IBR, see §63.14(b)) or ASTM D5198–92 (2003) (for biomass) (IBR, see §63.14(b)) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>d. Determine heat content of the fuel type * * *</td>
<td>ASTM D5865–04 (for coal) (IBR, see §63.24(b)) or ASTM E711–87 (for biomass) (IBR, see §63.14(b)) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>e. Determine moisture</td>
<td>ASTM D3173–03 (IBR, see §63.14(b)) or ASTM E871–82</td>
</tr>
<tr>
<td>2. Total Selected metals</td>
<td>a. Collect fuel samples</td>
<td>Procedure in §63.7521(c) or ASTM D2234–D2234M–03 (for coal) (IBR, see §63.14(b)) or ASTM D6323–98 (2003) (for biomass) (IBR, see §63.14(b)) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>b. Composite fuel samples</td>
<td>Procedure in §63.7521(d) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>c. Prepare composited fuel samples</td>
<td>SW–846–3050B (for solid samples) or SW–846–3020A (for liquid samples) or ASTM D2013–04 (for coal) (IBR, see §63.14(b)) or ASTM D5198–92 (2003) (for biomass (IBR, see §63.14(b)) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>d. Determine heat content of the fuel type</td>
<td>ASTM D5865–04 (for coal) (IBR, see §63.14(b)) or ASTM E711–87 (for biomass) (IBR, see §63.14(b)) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>e. Determine moisture content of the fuel type</td>
<td>ASTM D3173–03 (IBR, see §63.14(b)) or ASTM E871–82 (IBR, see §63.14(b)) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>f. Measure total selected metals concentration in fuel sample</td>
<td>SW–846–6010B or ASTM D6357–04 (for arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel for all solid fuels) and ASTM D4606–03 (for selenium in coal) (IBR, see §63.14(b)) or ASTM E885–88 (1996) for biomass) (IBR, see §63.14(b)) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.</td>
<td></td>
</tr>
<tr>
<td>3. Hydrogen Chloride</td>
<td>a. Collect fuel samples</td>
<td>Procedure in §63.7521(c) or ASTM D2234–D2234M–03 (for coal) (IBR, see §63.14(b)) or ASTM D6323–98 (2003) (for biomass) (IBR, see §63.14(b)) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>b. Composite fuel samples</td>
<td>Procedure in §63.7521(d) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>c. Prepare composited fuel</td>
<td>SW–846–3050B (for solid samples) or SW–846–3020A (for liquid samples) or equivalent.</td>
</tr>
<tr>
<td>samples</td>
<td>liquid samples) or ASTM D2013–04 (for coal) (IBR, see §63.14(b)) or ASTM D5198–92 (2003) (for biomass) (IBR, see §63.14(b)) or equivalent.</td>
<td></td>
</tr>
<tr>
<td>d. Determine heat content of the fuel type</td>
<td>ASTM D5865–04 (for coal) (IBR, see §63.14(b)) or ASTM E711–87 (1996) (for biomass) (IBR, see §63.14(b)) or equivalent.</td>
<td></td>
</tr>
<tr>
<td>e. Determine moisture content of the fuel type</td>
<td>ASTM D3173–03 (IBR, see §63.14(b)) or ASTM E871–82 (1998) or equivalent.</td>
<td></td>
</tr>
<tr>
<td>f. Measure chlorine concentration in fuel sample</td>
<td>SW–846–9250 or ASTM D6721–01 (for coal) or ASTM E776–87 (1996) (for biomass) (IBR, see §63.14(b)) or equivalent.</td>
<td></td>
</tr>
<tr>
<td>g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

[ 71 FR 70663, Dec. 6, 2006]

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits

As stated in §63.7520, you must comply with the following requirements for establishing operating limits:

<table>
<thead>
<tr>
<th>If you have an applicable emission limit for . . .</th>
<th>And your operating limits are based on . . .</th>
<th>You must . . .</th>
<th>Using . . .</th>
<th>According to the following requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Particulate matter, mercury, or total selected metals</td>
<td>a. Wet scrubber operating parameters</td>
<td>i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to §63.7530(c)</td>
<td>(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test</td>
<td>(a) You must collect pressure drop and liquid flow-rate data every 15 minutes during the entire period of the performance tests;</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>(b) Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance test by</td>
</tr>
<tr>
<td>Operating Parameters</td>
<td>Establishment Details</td>
<td>Data Collection</td>
<td>Performance Test Calculation</td>
<td></td>
</tr>
<tr>
<td>----------------------</td>
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<td></td>
</tr>
<tr>
<td><strong>b. Electrostatic precipitator operating parameters</strong> (option only for units with additional wet scrubber control)</td>
<td>i. Establish a site-specific minimum voltage and secondary current or total power input according to §63.7530(c)</td>
<td>(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test</td>
<td>(a) You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests; (b) Determine the average voltage and secondary current or total power input for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.</td>
<td></td>
</tr>
<tr>
<td><strong>2. Hydrogen Chloride</strong></td>
<td><strong>a. Wet scrubber operating parameters</strong></td>
<td>i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to §63.7530(c)</td>
<td>(1) Data from the pH, pressure drop, and liquid flow-rate monitors and the hydrogen chloride performance test</td>
<td>(a) You must collect pH, pressure drop, and liquid flow-rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average pH, pressure drop, and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.</td>
</tr>
<tr>
<td></td>
<td><strong>b. Dry scrubber operating parameters</strong></td>
<td>i. Establish a site-specific minimum sorbent injection rate operating limit according to §63.7530(c)</td>
<td>(1) Data from the sorbent injection rate monitors and hydrogen chloride performance test</td>
<td>(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests;</td>
</tr>
</tbody>
</table>
(b) Determine the average sorbent injection rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.

Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance

As stated in §63.7540, you must show continuous compliance with the emission limitations for affected sources according to the following:

<table>
<thead>
<tr>
<th>If you must meet the following operating limits or work practice standards . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Opacity</td>
<td>a. Collecting the opacity monitoring system data according to §§63.7525(b) and 63.7535; and</td>
</tr>
<tr>
<td></td>
<td>b. Reducing the opacity monitoring data to 6-minute averages; and</td>
</tr>
<tr>
<td></td>
<td>c. Maintaining opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent for existing sources; or maintaining opacity to less than or equal to 10 percent (1-hour block average) for new sources.</td>
</tr>
<tr>
<td>2. Fabric Filter Bag Leak Detection Operation</td>
<td>Installing and operating a bag leak detection system according to §63.7525 and operating the fabric filter such that the requirements in §63.7540(a)(9) are met.</td>
</tr>
<tr>
<td>3. Wet Scrubber Pressure Drop and Liquid Flow-rate</td>
<td>a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§63.7525 and 63.7535; and</td>
</tr>
<tr>
<td></td>
<td>b. Reducing the data to 3-hour block averages; and</td>
</tr>
<tr>
<td></td>
<td>c. Maintaining the 3-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to §63.7530(c).</td>
</tr>
<tr>
<td>4. Wet Scrubber pH</td>
<td>a. Collecting the pH monitoring system data according to §§63.7525 and 63.7535; and</td>
</tr>
<tr>
<td></td>
<td>b. Reducing the data to 3-hour block averages; and</td>
</tr>
<tr>
<td></td>
<td>c. Maintaining the 3-hour average pH at or above the operating limit established during the performance test according to §63.7530(c).</td>
</tr>
</tbody>
</table>
5. Dry Scrubber Sorbent or Carbon Injection Rate

- a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§63.7525 and 63.7535; and

- b. Reducing the data to 3-hour block averages; and

- c. Maintaining the 3-hour average sorbent or carbon injection rate at or above the operating limit established during the performance test according to §§63.7530(c).

6. Electrostatic Precipitator Secondary Current and Voltage or Total Power Input

- a. Collecting the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to §§63.7525 and 63.7535; and

- b. Reducing the data to 3-hour block averages; and

- c. Maintaining the 3-hour average secondary current and voltage or total power input at or above the operating limits established during the performance test according to §§63.7530(c).

7. Fuel Pollutant Content

- a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to §63.7530(c) or (d) as applicable; and

- b. Keeping monthly records of fuel use according to §63.7540(a).

---

Table 9 to Subpart DDDDD of Part 63—Reporting Requirements

As stated in §63.7550, you must comply with the following requirements for reports:

<table>
<thead>
<tr>
<th>You must submit a(n)</th>
<th>The report must contain . . .</th>
<th>You must submit the report . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Compliance report</td>
<td>a. Information required in §63.7550(c)(1) through (11); and</td>
<td>Semiannually according to the requirements in §63.7550(b).</td>
</tr>
<tr>
<td></td>
<td>b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous</td>
<td></td>
</tr>
</tbody>
</table>
opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and

c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in §63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in §63.8(c)(7), the report must contain the information in §63.7550(e); and

d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in §63.10(d)(5)(i)

2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard

<table>
<thead>
<tr>
<th></th>
<th>a. Actions taken for the event; and</th>
<th>i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>b. The information in §63.10(d)(5)(ii)</td>
<td>ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.</td>
</tr>
</tbody>
</table>

Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD
As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

<table>
<thead>
<tr>
<th>Citation</th>
<th>Subject</th>
<th>Brief description</th>
<th>Applicable</th>
</tr>
</thead>
<tbody>
<tr>
<td>§63.1</td>
<td>Applicability</td>
<td>Initial Applicability Determination; Applicability After Standard Established; Permit Requirements; Extensions, Notifications</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.2</td>
<td>Definitions</td>
<td>Definitions for part 63 standards</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.3</td>
<td>Units and Abbreviations</td>
<td>Units and abbreviations for part 63 standards</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.4</td>
<td>Prohibited Activities</td>
<td>Prohibited Activities; Compliance date; Circumvention, Severability</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.5</td>
<td>Construction/Reconstruction</td>
<td>Applicability; applications; approvals</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(a)</td>
<td>Applicability</td>
<td>GP apply unless compliance extension; and GP apply to area sources that become major</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(b)(1)–(4)</td>
<td>Compliance Dates for New and Reconstructed sources</td>
<td>Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for 112(f)</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(b)(5)</td>
<td>Notification</td>
<td>Must notify if commenced construction or reconstruction after proposal</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(b)(6)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.6(b)(7)</td>
<td>Compliance Dates for New and Reconstructed Area Sources That Become Major</td>
<td>Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(c)(1)–(2)</td>
<td>Compliance Dates for Existing Sources</td>
<td>Comply according to date in subpart, which must be no later than 3 years after effective date; and for 112(f) standards, comply within 90 days of effective date unless compliance extension</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(c)(3)–(4)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.6(c)(5)</td>
<td>Compliance Dates for Existing Area Sources That Become Major</td>
<td>Area sources that become major must comply with major source standards by date indicated in subpart or by equivalent time period (for example, 3 years)</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(d)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
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<tr>
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<td></td>
</tr>
<tr>
<td>§63.6(e)(1)–(2)</td>
<td>Operation &amp; Maintenance</td>
<td>Operate to minimize emissions at all times; and Correct malfunctions as soon as practicable; and Operation and maintenance requirements independently enforceable; information Administrator will use to determine if operation and maintenance requirements were met</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(e)(3)</td>
<td>Startup, Shutdown, and Malfunction Plan (SSMP)</td>
<td>Requirement for SSM and startup, shutdown, malfunction plan; and content of SSMP</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(f)(1)</td>
<td>Compliance Except During SSM</td>
<td>Comply with emission standards at all times except during SSM</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(f)(2)–(3)</td>
<td>Methods for Determining Compliance</td>
<td>Compliance based on performance test, operation and maintenance plans, records, inspection</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(g)(1)–(3)</td>
<td>Alternative Standard</td>
<td>Procedures for getting an alternative standard</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(h)(1)</td>
<td>Compliance with Opacity/VE Standards</td>
<td>Comply with opacity/VE emission limitations at all times except during SSM</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(h)(2)(i)</td>
<td>Determining Compliance with Opacity/Visible Emission (VE) Standards</td>
<td>If standard does not state test method, use Method 9 for opacity and Method 22 for VE</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(h)(2)(ii)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.6(h)(2)(iii)</td>
<td>Using Previous Tests to Demonstrate Compliance with Opacity/VE Standards</td>
<td>Criteria for when previous opacity/VE testing can be used to show compliance with this subpart</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(h)(3)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.6(h)(4)</td>
<td>Notification of Opacity/VE Observation Date</td>
<td>Notify Administrator of anticipated date of observation</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(h)(5)(i), (iii)–(v)</td>
<td>Conducting Opacity/VE Observations</td>
<td>Dates and Schedule for conducting opacity/VE observations</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(h)(5)(ii)</td>
<td>Opacity Test Duration and Averaging Times</td>
<td>Must have at least 3 hours of observation with thirty, 6-minute averages</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(h)(6)</td>
<td>Records of Conditions During Opacity/VE observations</td>
<td>Keep records available and allow Administrator to inspect</td>
<td>No.</td>
</tr>
<tr>
<td>Section</td>
<td>Requirement</td>
<td>Compliance</td>
<td></td>
</tr>
<tr>
<td>--------------</td>
<td>------------------------------------------------------------------</td>
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<td></td>
</tr>
<tr>
<td>§63.6(h)(7)(i)</td>
<td>Report continuous opacity monitoring system Monitoring Data from Performance Test</td>
<td>Submit continuous opacity monitoring system data with other performance test data</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(h)(7)(ii)</td>
<td>Using continuous opacity monitoring system instead of Method 9</td>
<td>Can submit continuous opacity monitoring system data instead of Method 9 results even if subpart requires Method 9, but must notify Administrator before performance test</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(h)(7)(iii)</td>
<td>Averaging time for continuous opacity monitoring system during performance test</td>
<td>To determine compliance, must reduce continuous opacity monitoring system data to 6-minute averages</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(h)(7)(iv)</td>
<td>Continuous opacity monitoring system requirements</td>
<td>Demonstrate that continuous opacity monitoring system performance evaluations are conducted according to §§63.8(e), continuous opacity monitoring systems are properly maintained and operated according to §63.8(c) and data quality as §63.8(d)</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(h)(7)(v)</td>
<td>Determining Compliance with Opacity/VE Standards</td>
<td>Continuous opacity monitoring system is probative but not conclusive evidence of compliance with opacity standard, even if Method 9 observation shows otherwise. Requirements for continuous opacity monitoring system to be probative evidence-proper maintenance, meeting PS 1, and data have not been altered</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(h)(8)</td>
<td>Determining Compliance with Opacity/VE Standards</td>
<td>Administrator will use all continuous opacity monitoring system, Method 9, and Method 22 results, as well as information about operation and maintenance to determine compliance</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(h)(9)</td>
<td>Adjusted Opacity Standard</td>
<td>Procedures for Administrator to adjust an opacity standard</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(i)(1)–(14)</td>
<td>Compliance Extension</td>
<td>Procedures and criteria for Administrator to grant compliance extension</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(j)</td>
<td>Presidential Compliance Exemption</td>
<td>President may exempt source category from requirement to comply with rule</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.7(a)(1)</td>
<td>Performance Test Dates</td>
<td>Dates for Conducting Initial Performance Testing and Other Compliance</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.7(a)(2)</td>
<td>Performance Test Dates</td>
<td>New source with initial startup date before effective date has 180 days after effective date to demonstrate compliance</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.7(a)(2)(ii–viii)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.7(a)(2)(ix)</td>
<td>Performance Test Dates</td>
<td>1. New source that commenced construction between proposal and promulgation dates, when promulgated standard is more stringent than proposed standard, has 180 days after effective date or 180 days after startup of source, whichever is later, to demonstrate compliance; and No.</td>
<td>Yes.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2. If source initially demonstrates compliance with less stringent proposed standard, it has 3 years and 180 days after the effective date of the standard or 180 days after startup of source, whichever is later, to demonstrate compliance with promulgated standard</td>
<td></td>
</tr>
<tr>
<td>§63.7(a)(3)</td>
<td>Section 114 Authority</td>
<td>Administrator may require a performance test under CAA Section 114 at any time</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.7(b)(1)</td>
<td>Notification of Performance Test</td>
<td>Must notify Administrator 60 days before the test</td>
<td>No.</td>
</tr>
<tr>
<td>§63.7(b)(2)</td>
<td>Notification of Rescheduling</td>
<td>If rescheduling a performance test is necessary, must notify Administrator 5 days before scheduled date of rescheduled date</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.7(c)</td>
<td>Quality Assurance/Test Plan</td>
<td>Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with: test plan approval procedures; and performance audit requirements; and internal and external QA procedures for testing</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.7(d)</td>
<td>Testing Facilities</td>
<td>Requirements for testing facilities</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.7(e)(1)</td>
<td>Conditions for Conducting Performance Tests</td>
<td>1. Performance tests must be conducted under representative conditions; and No.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>2. Cannot conduct performance tests during SSM; and Yes.</td>
<td></td>
</tr>
<tr>
<td>Section</td>
<td>Description</td>
<td>Requirement</td>
<td>Result</td>
</tr>
<tr>
<td>---------</td>
<td>-------------------------------------------------</td>
<td>-------------</td>
<td>--------</td>
</tr>
<tr>
<td>§63.7(e)(2)</td>
<td>Conditions for Conducting Performance Tests</td>
<td>Must conduct according to rule and EPA test methods unless Administrator approves alternative</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.7(e)(3)</td>
<td>Test Run Duration</td>
<td>Must have three separate test runs; and Compliance is based on arithmetic mean of three runs; and conditions when data from an additional test run can be used</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.7(e)(4)</td>
<td>Interaction with other sections of the Act</td>
<td>Nothing in §63.7(e)(1) through (4) can abrogate the Administrator's authority to require testing under Section 114 of the Act</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(a)(1)</td>
<td>Applicability of Monitoring Requirements</td>
<td>Subject to all monitoring requirements in standard</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(a)(2)</td>
<td>Performance Specifications</td>
<td>Performance Specifications in appendix B of part 60 apply</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(a)(3)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.8(a)(4)</td>
<td>Monitoring with Flares</td>
<td>Unless your rule says otherwise, the requirements for flares in §63.11 apply</td>
<td>No.</td>
</tr>
<tr>
<td>§63.8(b)(1)(i)–(ii)</td>
<td>Monitoring</td>
<td>Must conduct monitoring according to standard unless Administrator approves alternative</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(b)(1)(iii)</td>
<td>Monitoring</td>
<td>Flares not subject to this section unless otherwise specified in relevant standard</td>
<td>No.</td>
</tr>
<tr>
<td>§63.8(b)(2)--(3)</td>
<td>Multiple Effluents and Multiple Monitoring Systems</td>
<td>Specific requirements for installing monitoring systems; and must install on each effluent before it is combined and before it is released to the atmosphere unless Administrator approves otherwise; and if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(1)</td>
<td>Monitoring System Operation and Maintenance</td>
<td>Maintain monitoring system in a manner consistent with good air pollution control practices</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(1)(i)</td>
<td>Routine and Predictable SSM</td>
<td>Maintain and operate CMS according to §63.6(e)(1)</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(1)(ii)</td>
<td>SSM not in SSMP</td>
<td>Must keep necessary parts available for routine repairs of CMSs</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(1)(iii)</td>
<td>Compliance with Operation and Maintenance</td>
<td>Must develop an SSMP for CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(2)--(3)</td>
<td>Monitoring System Installation</td>
<td>Must install to get representative emission and parameter measurements; and must verify operational status before or at performance test</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(4)</td>
<td>Continuous Monitoring System (CMS) Requirements</td>
<td>CMSs must be operating except during breakdown, out-of-control, repair, maintenance, and high-level calibration drifts</td>
<td>No.</td>
</tr>
<tr>
<td>§63.8(c)(4)(i)</td>
<td>Continuous Monitoring System (CMS) Requirements</td>
<td>Continuous opacity monitoring system must have a minimum of one cycle of sampling and analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(4)(ii)</td>
<td>Continuous Monitoring System (CMS) Requirements</td>
<td>Continuous emissions monitoring system must have a minimum of one cycle of operation for each successive 15-minute period</td>
<td>No.</td>
</tr>
<tr>
<td>§63.8(c)(5)</td>
<td>Continuous Opacity Monitoring system (COMS) Requirements</td>
<td>Must do daily zero and high level calibrations</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(6)</td>
<td>Continuous Monitoring System</td>
<td>Must do daily zero and high level calibrations</td>
<td>No.</td>
</tr>
<tr>
<td><strong>§63.8(c)(7)–(8)</strong></td>
<td>(CMS) Requirements</td>
<td>calibrations</td>
<td>Out-of-control periods, including reporting</td>
</tr>
<tr>
<td>---------------------</td>
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<td>---------------------------------------------</td>
</tr>
<tr>
<td><strong>§63.8(d)</strong></td>
<td>Continuous Monitoring Systems Requirements</td>
<td>Requirements for continuous monitoring systems quality control, including calibration, etc.; and must keep quality control plan on record for the life of the affected source. Keep old versions for 5 years after revisions</td>
<td></td>
</tr>
<tr>
<td><strong>§63.8(e)</strong></td>
<td>Continuous Monitoring Systems Quality Control</td>
<td>Notification, performance evaluation test plan, reports</td>
<td></td>
</tr>
<tr>
<td><strong>§63.8(f)(1)–(5)</strong></td>
<td>Alternative Monitoring Method</td>
<td>Procedures for Administrator to approve alternative monitoring</td>
<td></td>
</tr>
<tr>
<td><strong>§63.8(f)(6)</strong></td>
<td>Alternative to Relative Accuracy Test</td>
<td>Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system</td>
<td></td>
</tr>
<tr>
<td><strong>§63.8(g)(1)–(4)</strong></td>
<td>Data Reduction</td>
<td>Continuous opacity monitoring system 6-minute averages calculated over at least 36 evenly spaced data points; and continuous emissions monitoring system 1-hour averages computed over at least 4 equally spaced data points</td>
<td></td>
</tr>
<tr>
<td><strong>§63.8(g)(5)</strong></td>
<td>Data Reduction</td>
<td>Data that cannot be used in computing averages for continuous emissions monitoring system and continuous opacity monitoring system</td>
<td></td>
</tr>
<tr>
<td><strong>§63.9(a)</strong></td>
<td>Notification Requirements</td>
<td>Applicability and State Delegation</td>
<td></td>
</tr>
<tr>
<td><strong>§63.9(b)(1)–(5)</strong></td>
<td>Initial Notifications</td>
<td>Submit notification 120 days after effective date; and Notification of intent to construct/reconstruct; and Notification of commencement of construct/reconstruct; Notification of startup; and Contents of each</td>
<td></td>
</tr>
<tr>
<td><strong>§63.9(c)</strong></td>
<td>Request for Compliance Extension</td>
<td>Can request if cannot comply by date or if installed BACT/LAER</td>
<td></td>
</tr>
<tr>
<td><strong>§63.9(d)</strong></td>
<td>Notification of Special Compliance Requirements for New Source</td>
<td>For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date</td>
<td></td>
</tr>
<tr>
<td>Section</td>
<td>Description</td>
<td>Requirement</td>
<td>Result</td>
</tr>
<tr>
<td>-----------</td>
<td>------------------------------------------------------------------------------</td>
<td>------------------------------------------------------------------------------</td>
<td>--------</td>
</tr>
<tr>
<td>§63.9(e)</td>
<td>Notification of Performance Test</td>
<td>Notify Administrator 60 days prior</td>
<td>No.</td>
</tr>
<tr>
<td>§63.9(f)</td>
<td>Notification of VE/Opacity Test</td>
<td>Notify Administrator 30 days prior</td>
<td>No.</td>
</tr>
<tr>
<td>§63.9(g)</td>
<td>Additional Notifications When Using Continuous Monitoring Systems</td>
<td>Notification of performance evaluation; and notification using continuous opacity monitoring system data; and notification that exceeded criterion for relative accuracy</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.9(h)(1)–(6)</td>
<td>Notification of Compliance Status</td>
<td>Contents; and due 60 days after end of performance test or other compliance demonstration, and when to submit to Federal vs. State authority</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.9(i)</td>
<td>Adjustment of Submittal Deadlines</td>
<td>Procedures for Administrator to approve change in when notifications must be submitted</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.9(j)</td>
<td>Change in Previous Information</td>
<td>Must submit within 15 days after the change</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(a)</td>
<td>Recordkeeping/Reporting</td>
<td>Applies to all, unless compliance extension; and when to submit to Federal vs. State authority; and procedures for owners of more than 1 source</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(1)</td>
<td>Recordkeeping/Reporting</td>
<td>General Requirements; and keep all records readily available and keep for 5 years</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(i)–(v)</td>
<td>Records related to Startup, Shutdown, and Malfunction</td>
<td>Occurrence of each of operation (process, equipment); and occurrence of each malfunction of air pollution equipment; and maintenance of air pollution control equipment; and actions during startup, shutdown, and malfunction</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(vi) and (x–xi)</td>
<td>Continuous monitoring systems Records</td>
<td>Malfunctions, inoperative, out-of-control; and calibration checks; and adjustments, maintenance</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(vii)–(ix)</td>
<td>Records</td>
<td>Measurements to demonstrate compliance with emission limitations; and performance test, performance evaluation, and visible emission observation results; and measurements to</td>
<td>Yes.</td>
</tr>
</tbody>
</table>
| Section | Type | Description | Requirement
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>§63.10(b)(2)(xii)</td>
<td>Records</td>
<td>Records when under waiver</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(xiii)</td>
<td>Records</td>
<td>Records when using alternative to relative accuracy test</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(b)(2)(xiv)</td>
<td>Records</td>
<td>All documentation supporting Initial Notification and Notification of Compliance Status</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(3)</td>
<td>Records</td>
<td>Applicability Determinations</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(c)(1),(5–(8),(10–(15)</td>
<td>Records</td>
<td>Additional Records for continuous monitoring systems</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(c)(7–(8)</td>
<td>Records</td>
<td>Records of excess emissions and parameter monitoring exceedances for continuous monitoring systems</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(d)(1)</td>
<td>General Reporting Requirements</td>
<td>Requirement to report</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(d)(2)</td>
<td>Report of Performance Test Results</td>
<td>When to submit to Federal or State authority</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(d)(3)</td>
<td>Reporting Opacity or VE Observations</td>
<td>What to report and when</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(d)(4)</td>
<td>Progress Reports</td>
<td>Must submit progress reports on schedule if under compliance extension</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(d)(5)</td>
<td>Startup, Shutdown, and Malfunction Reports</td>
<td>Contents and submission</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(e)(1)(2)</td>
<td>Additional continuous monitoring systems Reports</td>
<td>Must report results for each CEM on a unit; and written copy of performance evaluation; and 3 copies of continuous opacity monitoring system performance evaluation</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(e)(3)</td>
<td>Reports</td>
<td>Excess Emission Reports</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(e)(3)(i–iii)</td>
<td>Reports</td>
<td>Schedule for reporting excess emissions and parameter monitor exceedance (now defined as deviations)</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(e)(3)(iv–v)</td>
<td>Excess Emissions Reports</td>
<td>Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(e)(3)(iv–v)</td>
<td>Excess Emissions Reports</td>
<td>Must submit report containing all of the information in §63.10(c)(5–13), §63.8(c)(7–8)</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(e)(3)(vi–viii)</td>
<td>Excess Emissions Report and Summary Report</td>
<td>Requirements for reporting excess emissions for continuous monitoring systems (now called deviations); Requires all of the information in §63.10(c)(5–13), §63.8(c)(7–8)</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(e)(4)</td>
<td>Reporting continuous opacity monitoring system data</td>
<td>Must submit continuous opacity monitoring system data with performance test data</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(f)</td>
<td>Waiver for Recordkeeping/Reporting</td>
<td>Procedures for Administrator to waive</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.11</td>
<td>Flares</td>
<td>Requirements for flares</td>
<td>No.</td>
</tr>
<tr>
<td>§63.12</td>
<td>Delegation</td>
<td>State authority to enforce standards</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.13</td>
<td>Addresses</td>
<td>Addresses where reports, notifications, and requests are sent</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.14</td>
<td>Incorporation by Reference</td>
<td>Test methods incorporated by reference</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.15</td>
<td>Availability of Information</td>
<td>Public and confidential Information</td>
<td>Yes.</td>
</tr>
</tbody>
</table>


Appendix A to Subpart DDDDD of Part 63—Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives

1. Purpose/Introduction

This appendix provides the methodology and criteria for demonstrating that your affected source is eligible for the compliance alternative for the HCl emission limit and/or the total selected metals (TSM) emission limit. This appendix specifies emissions testing methods that you must use to determine HCl, chlorine, and manganese emissions from the affected units and what parts of the affected source facility must be included in the eligibility demonstration. You must demonstrate that your affected source is
eligible for the health-based compliance alternatives using either a look-up table analysis (based on the look-up tables included in this appendix) or a site-specific compliance demonstration performed according to the criteria specified in this appendix. This appendix also specifies how and when you file any eligibility demonstrations for your affected source and how to show that your affected source remains eligible for the health-based compliance alternatives in the future.

2. Who Is Eligible To Demonstrate That They Qualify for the Health-Based Compliance Alternatives?

Each new, reconstructed, or existing affected source may demonstrate that they are eligible for the health-based compliance alternatives. Section 63.7490 of subpart DDDDD defines the affected source and explains which affected sources are new, existing, or reconstructed.

3. What Parts of My Facility Have To Be Included in the Health-Based Eligibility Demonstration?

If you are attempting to determine your eligibility for the compliance alternative for HCl, you must include every emission point subject to subpart DDDDD that emits either HCl or Cl\textsubscript{2} in the eligibility demonstration.

If you are attempting to determine your eligibility for the compliance alternative for TSM, you must include every emission point subject to subpart DDDDD that emits manganese in the eligibility demonstration.

4. How Do I Determine HAP Emissions From My Affected Source?

(a) You must conduct HAP emissions tests or fuel analysis for every emission point covered under subpart DDDDD within the affected source facility according to the requirements in paragraphs (b) through (f) of this section and the methods specified in Table 1 of this appendix.

(1) If you are attempting to determine your eligibility for the compliance alternative for HCl, you must test the subpart DDDDD units at your facility for both HCl and Cl\textsubscript{2}. When conducting fuel analysis, you must assume any chlorine detected will be emitted as Cl\textsubscript{2}.

(2) If you are attempting to determine your eligibility for the compliance alternative for TSM, you must test the subpart DDDDD units at your facility for manganese.

(b) *Periods when emissions tests must be conducted.* (1) You must not conduct emissions tests during periods of startup, shutdown, or malfunction, as specified in §63.7(e)(1).

(2) You must test under worst-case operating conditions as defined in this appendix. You must describe your worst-case operating conditions in your performance test report for the process and control systems (if applicable) and explain why the conditions are worst-case.

(c) *Number of test runs.* You must conduct three separate test runs for each test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(d) *Sampling locations.* Sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere.

(e) *Collection of monitoring data for HAP control devices.* During the emissions test, you must collect operating parameter monitoring system data at least every 15 minutes during the entire emissions test.
and establish the site-specific operating requirements in Tables 3 or 4, as appropriate, of subpart DDDDD using data from the monitoring system and the procedures specified in §63.7530 of subpart DDDDD.

(f) **Nondetect data.** You may treat emissions of an individual HAP as zero if all of the test runs result in a nondetect measurement and the condition in paragraph (f)(1) of this section is met for the manganese test method. Otherwise, nondetect data for individual HAP must be treated as one-half of the method detection limit.

(1) For manganese measured using Method 29 in appendix A to 40 CFR part 60, you analyze samples using atomic absorption spectroscopy (AAS).

(g) You must determine the maximum hourly emission rate for each appropriate emission point according to Equation 1 of this appendix. An appropriate emission point is any emission point emitting HCl, Cl$_2$, or Manganese from a subpart DDDDD emission unit.

$$E_{i,s} = \sum_{j}^{t} \left( \frac{R_{i,j} \times I_j}{t} \right)$$  \hspace{1cm} (Eq. 1)

Where:

- $E_{i,s}$ = maximum hourly emission rate for HAP $i$ at each emission point $s$ associated with a subpart DDDDD emission unit $j$, lbs/hr
- $i$ = applicable HAP, where $i$ = (HCl, Cl$_2$, or Manganese)
- $s$ = individual emission point
- $j$ = each subpart DDDDD emission unit associated with an emission point, $s$
- $t$ = total number of subpart DDDDD emission units associated with an emission point $s$
- $R_{i,j}$ = emission rate (the 3-run average as determined according to table 1 of this appendix or the pollutant concentration in the fuel samples analyzed according to §63.7521) for HAP $i$ at subpart DDDDD emission unit $j$ associated with emission point $s$, lb per million Btu.
- $I_j$ = Maximum rated heat input capacity of each subpart DDDDD unit $j$ emitting HAP $i$ associated with emission point $s$, million Btu per hour.

5. **What Are the Criteria for Determining If My Facility Is Eligible for the Health-Based Compliance Alternatives?**

(a) Determine the HAP emissions from each appropriate emission point within the affected source facility using the procedures specified in section 4 of this appendix.

(b) Demonstrate that your facility is eligible for either of the health-based compliance alternatives using either the methods described in section 6 of this appendix (look-up table analysis) or section 7 of this appendix (site-specific compliance demonstration).

(c) Your facility is eligible for the health-based compliance alternative for HCl if one of the following two statements is true:
(1) The calculated HCl-equivalent emission rate is below the appropriate value in the look-up table;

(2) Your site-specific compliance demonstration indicates that none of your HI values for HCl and Cl₂ are greater than 1.0 at locations where people live or congregate (e.g., schools, daycare centers, etc.);

(d) Your facility is eligible for the health-based compliance alternative for TSM if one of the following two statements is true:

(1) The manganese emission rate for all your subpart DDDDD sources is below the appropriate value in the look-up table;

(2) Your site-specific compliance demonstration indicates that none of your HQ values for manganese are greater than 1.0 at locations where people live or congregate (e.g., schools, daycare centers, etc.).

6. How Do I Conduct a Look-Up Table Analysis?

You may use look-up tables to demonstrate that your facility is eligible for either the compliance alternative for HCl emissions limit or the compliance alternative for the TSM emissions limit, unless your permitting authority determines that the look-up table analysis in this section is not applicable to your facility on technical grounds due to site-specific variations that are not accounted for in the look-up table analysis (e.g. presence of complex terrain, rain caps, or building downwash effects).

(a) HCl compliance alternative. (1) Using the emission rates for HCl and Cl₂ determined according to section 4 of this appendix, calculate, using equation 2 of this appendix, the toxicity-weighted emission rate (expressed in HCl-equivalents) for each emission point that emits HCl or Cl₂ from any subpart DDDDD sources. Then, calculate the weighted average stack height using equation 3 of this appendix.

\[
TW_s = E_{HCl,s} + E_{Cl_2,s} \left( \frac{RV_{HCl}}{RV_{Cl_2}} \right) \quad (\text{Eq. 2})
\]

Where:

\(TW_s\) = the toxicity-weighted emission rate (in HCl-equivalent) for each emission point s, lb/hr.

\(s\) = individual emission points

\(E_{HCl,s}\) = the maximum hourly emission rate for HCl at emission point s, lb/hr

\(E_{Cl_2,s}\) = the maximum hourly emission rate for Cl₂ at emission point s, lb/hr

\(RV_{Cl_2}\) = the reference value for Cl₂

\(RV_{HCl}\) = the reference value for HCl

(reference values for HCl and Cl₂ can be found at [http://www.epa.gov/ttn/atw/toxsource/summary.html](http://www.epa.gov/ttn/atw/toxsource/summary.html)).
\[ H_{HCl} = \frac{\sum_{i=1}^{n} (TW_s \times H_s)}{TW_T} \quad (\text{Eq. 3}) \]

Where:

\( H_{HCl} \) = weighted average stack height for determining the maximum allowable HCl-equivalent emission rate (in Table 2 to this appendix), m.

\( s \) = individual emission points

\( n \) = total number of emission points

\( TW_s \) = toxicity-weighted HCl-equivalent emission rate from each emission point (from equation 2), lb/hr.

\( H_s \) = height of each individual stack, m

\( TW_T \) = total toxicity-weighted HCl-equivalent emission rate from the source (summed for all emission points), lb/hr.

(2) Calculate the total toxicity-weighted emission rate for your affected source by summing the toxicity-weighted emission rate for each appropriate subpart DDDDD emission point.

(3) Using the weighted average stack height and the minimum distance between any appropriate subpart DDDDD emission point at the source and the property boundary, identify the appropriate maximum allowable toxicity weighted emission rate for your affected source, expressed in HCl-equivalents, from table 2 of this appendix. Appropriate emission points are those that emit HCl or Cl\(_2\), or both, from subpart DDDDD units. If one or both of these values does not match the exact values in the look-up tables, then use the next lowest table value. (Note: If your weighted average stack height is less than 5 meters (m), you must use the 5 meter row.) Your affected source is eligible to comply with the health-based alternative for HCl emissions if the value calculated in paragraph (a)(2) of this section, determined using the methods specified in this appendix, does not exceed the appropriate value in table 2 of this appendix.

(b) \textit{TSM Compliance Alternative}. Using the emission rates for manganese determined according to section 4 of this appendix, calculate the total manganese emission rate for your affected source by summing the maximum hourly manganese emission rates for all your subpart DDDDD units. Identify the appropriate allowable emission rate in table 3 of this appendix for your affected source using the weighted average stack height value and the minimum distance between any appropriate subpart DDDDD emission point at the facility and the property boundary. Appropriate emission points are those that emit manganese from subpart DDDDD units. If one or both of these values does not match the exact values in the look-up tables, then use the next lowest table value. (Note: If your weighted average stack height is less than 5 meters, you must use the 5 meter row.) Your affected source is eligible to comply with the health-based alternative for manganese emissions and may exclude manganese when demonstrating compliance with the TSM emission limit if the total manganese emission rate, determined using the methods specified in this appendix, does not exceed the appropriate value specified in table 3 of this appendix.
Where:

\[ H_{Mn} = \frac{\sum_s (E_{Mn,s} \times H_s)}{E_{Mn,T}} \]  

(Eq. 4)

\( H_{Mn} \) = weighted average stack height for determining the maximum allowable emission rate for manganese (in table 3 to this appendix), m.

\( s \) = individual emission points

\( n \) = total number of emission points

\( E_{Mn,s} \) = maximum hourly manganese emissions from emission point \( s \), lbs/hr.

\( H_s \) = height of each individual stack \( s \)

\( E_{Mn,T} \) = total maximum hourly manganese emissions from affected source (sum emission rates from all emission points), lb/hr

7. How Do I Conduct a Site-Specific Compliance Demonstration?

If you fail to demonstrate that your facility is able to comply with one or both of the alternative health-based emission standards using the look-up table approach, you may choose to perform a site-specific compliance demonstration for your facility. You may use any scientifically-accepted peer-reviewed risk assessment methodology for your site-specific compliance demonstration. An example of one approach for performing a site-specific compliance demonstration for air toxics can be found in the EPA’s “Air Toxics Risk Assessment Reference Library, Volume 2, Site-Specific Risk Assessment Technical Resource Document”, which may be obtained through the EPA’s Air Toxics Web site at http://www.epa.gov/ttn/fera/risk_atoxic.html.

(a) Your facility is eligible for the HCl alternative compliance option if your site-specific compliance demonstration shows that the maximum HI for HCl and Cl\(_2\) from your subpart DDDDD sources is less than or equal to 1.0.

(b) Your facility is eligible for the TSM alternative compliance option if your site-specific compliance demonstration shows that the maximum HQ for manganese from your subpart DDDDD sources is less than or equal to 1.0.

(c) At a minimum, your site-specific compliance demonstration must:

1. Estimate long-term inhalation exposures through the estimation of annual or multi-year average ambient concentrations;
2. Estimate the inhalation exposure for the individual most exposed to the facility’s emissions;
3. Use site-specific, quality-assured data wherever possible;
(4) Use health-protective default assumptions wherever site-specific data are not available, and;

(5) Contain adequate documentation of the data and methods used for the assessment so that it is transparent and can be reproduced by an experienced risk assessor and emissions measurement expert.

(d) Your site-specific compliance demonstration need not:

(1) Assume any attenuation of exposure concentrations due to the penetration of outdoor pollutants into indoor exposure areas;

(2) Assume any reaction or deposition of the emitted pollutants during transport from the emission point to the point of exposure.

8. What Must My Health-Based Eligibility Demonstration Contain?

(a) Your health-based eligibility demonstration must contain, at a minimum, the information specified in paragraphs (a)(1) through (6) of this section.

(1) Identification of each appropriate emission point at the affected source facility, including the maximum rated capacity of each appropriate emission point.

(2) Stack parameters for each appropriate emission point including, but not limited to, the parameters listed in paragraphs (a)(2)(i) through (iv) below:

(i) Emission release type.

(ii) Stack height, stack area, stack gas temperature, and stack gas exit velocity.

(iii) Plot plan showing all emission points, nearby residences, and fenceline.

(iv) Identification of any control devices used to reduce emissions from each appropriate emission point.

(3) Emission test reports for each pollutant and appropriate emission point which has been tested using the test methods specified in Table 1 of this appendix, including a description of the process parameters identified as being worst case. Fuel analyses for each fuel and emission point which has been conducted including collection and analytical methods used.

(4) Identification of the RfC values used in your look-up table analysis or site-specific compliance demonstration.

(5) Calculations used to determine the HCl-equivalent or manganese emission rates according to sections 6(a) or (b) of this appendix.

(6) Identification of the controlling process factors (including, but not limited to, fuel type, heat input rate, type of control devices, process parameters reflecting the emissions rates used for your eligibility demonstration) that will become Federally enforceable permit conditions used to show that your facility remains eligible for the health-based compliance alternatives.
(b) If you use the look-up table analysis in section 6 of this appendix to demonstrate that your facility is eligible for either health-based compliance alternative, your eligibility demonstration must contain, at a minimum, the information in paragraphs (a) and (b)(1) through (3) of this section.

(1) Calculations used to determine the weighted average stack height of the subpart DDDDD emission points that emit manganese, HCl, or Cl₂.

(2) Identification of the subpart DDDDD emission point, that emits either manganese or HCl and Cl₂, with the minimum distance to the property boundary of the facility.

(3) Comparison of the values in the look-up tables (Tables 2 and 3 of this appendix) to your maximum HCl-equivalent or manganese emission rates.

(c) If you use a site-specific compliance demonstration as described in section 7 of this appendix to demonstrate that your facility is eligible, your eligibility demonstration must contain, at a minimum, the information in paragraphs (a) and (c)(1) through (7) of this section:

(1) Identification of the risk assessment methodology used.

(2) Documentation of the fate and transport model used.

(3) Documentation of the fate and transport model inputs, including the information described in paragraphs (a)(1) through (5) of this section converted to the dimensions required for the model and all of the following that apply: meteorological data; building, land use, and terrain data; receptor locations and population data; and other facility-specific parameters input into the model.

(4) Documentation of the fate and transport model outputs.

(5) Documentation of any exposure assessment and risk characterization calculations.

(6) Comparison of the HQ HI to the limit of 1.0.

(d) To be eligible for either health-based compliance alternative, the parameters that defined your affected source as eligible for the health-based compliance alternatives must be submitted to your permitting authority for incorporation into your title V permit, as federally enforceable limits, at the same time you submit your health-based eligibility demonstration. These parameters include, but are not limited to, fuel type, fuel mix (annual average), emission rate, type of control devices, process parameters (e.g., maximum heat input), and non-process parameters (e.g., stack height).

9. When Do I Have To Complete and Submit My Health-Based Eligibility Demonstration?

(a) If you have an existing affected source, you must complete and submit your eligibility demonstration to your permitting authority, along with a signed certification that the demonstration is an accurate depiction of your facility, no later than the date one year prior to the compliance date of subpart DDDDD. A separate copy of the eligibility demonstration must be submitted to: U.S. EPA, Risk and Exposure Assessment Group, Emission Standards Division (C404–01), Attn: Group Leader, Research Triangle Park, North Carolina 27711, electronic mail address REAG@epa.gov.
(b) If you have a new or reconstructed affected source that starts up before the effective date of subpart DDDDD, or an affected source that is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP before the effective date of subpart DDDDD, then you may submit an eligibility demonstration at any time after September 13, 2004 but you must comply with the emissions limits in table 1 to this subpart and all other requirements of subpart DDDDD until your eligibility demonstration is submitted to your permitting authority in accordance with the requirements of section 10 of this appendix.

(c) If you have a new or reconstructed affected source that starts up after the effective date of subpart DDDDD, or an affected source that is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP after the effective date for subpart DDDDD, then you must follow the schedule in paragraphs (c)(1) and (2) of this section.

(1) You must complete and submit a preliminary eligibility demonstration based on the information (e.g., equipment types, estimated emission rates, process and non-process parameters, reference values, etc.) that will be used to apply for your title V permit. This preliminary eligibility demonstration must be submitted with your application for approval of construction or reconstruction. You must base your preliminary eligibility demonstration on the maximum emissions allowed under your title V permit. If the preliminary eligibility demonstration indicates that your affected source facility is eligible for either compliance alternative, then you may start up your new affected source and your new affected source will be considered in compliance with the alternative standard and subject to the compliance requirements in this appendix.

(2) You must conduct the emission tests or analyses specified in section 4 of this appendix upon initial startup and use the results of these emissions tests to complete and submit your eligibility demonstration within 180 days following your initial startup date.

10. When Do I Become Eligible for the Health-Based Compliance Alternatives?

(a) For existing sources, new sources, or reconstructed sources that start up before the effective date of subpart DDDDD, or an affected source that is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP before the effective date of subpart DDDDD, you are eligible to comply with a health-based compliance alternative upon submission of a complete demonstration meeting all the requirements of paragraph 8 for the applicable alternative. However, your eligibility demonstration may be reviewed by the permitting authority or by EPA to verify that the demonstration meets the requirements of appendix A to this subpart and is technically sound (i.e. use of the look-up tables is appropriate or the site-specific assessment is technically valid). If you are notified by the permitting authority or by EPA of any deficiencies in your submission, then you are not eligible for the health-based compliance alternative until the permitting authority or EPA verifies that the deficiencies are corrected.

(b) For new or reconstructed sources that start up after the effective date of subpart DDDDD, you are eligible to comply with a the health-based compliance alternatives upon submission of a complete preliminary eligibility determination in accordance with paragraph (c)(1) of section 9 that demonstrates your affected source is eligible for the applicable alternative. You may then start up your source and conduct the necessary testing in accordance with paragraph (c)(2) of section 9. The eligibility demonstration submitted in accordance with paragraph (c)(2) of section 9 may be reviewed by the permitting authority or by EPA to verify that the demonstration meets the requirements of appendix A to this subpart and is technically sound (i.e. use of the look-up tables is appropriate or the site-specific...
assessment is technically valid). If you are notified in writing by the permitting authority of any deficiencies in your submission, then you have 30 days to correct the deficiencies unless the permitting authority agrees to extend this time to a period not to exceed 90 days. If the deficiencies are not corrected within the applicable time period, you will not be eligible for the health-based compliance alternative until the permitting authority verifies that the deficiencies are corrected.

(c) If the title V permit conditions requested in accordance with paragraph (d) of section 8 are disapproved by the permitting authority, then your affected source must comply with the applicable emission limits, operating limits, and work practice standards in subpart DDDDD by the compliance dates specified in §63.7495. Until the requested conditions (or alternative conditions meeting the requirements of paragraph (d) of section 8) are incorporated into the permit, compliance with the proposed conditions shall be considered compliance with the health-based alternative.

11. How Do I Ensure That My Facility Remains Eligible for the Health-Based Compliance Alternatives?

(a) You must update your eligibility demonstration and resubmit it each time that any of the parameters that defined your affected source as eligible for the health-based compliance alternatives changes in a way that could result in increased HAP emissions or increased risk from exposure to emissions. These parameters include, but are not limited to, fuel type, fuel mix (annual average), type of control devices, HAP emission rate, stack height, process parameters (e.g., heat input capacity), relevant reference values, and locations where people live).

(b) If you are updating your eligibility demonstration to account for an action in paragraph (a) of this section that is under your control (e.g. change in heat input capacity of your boiler), you must submit your revised eligibility demonstration to the permitting authority prior to making the change and revise your permit to incorporate the change. If your affected source is no longer eligible for the health-based compliance alternatives, then you must comply with the applicable emission limits, operating limits, and compliance requirements in subpart DDDDD prior to making the process change and revising your permit. If you are updating your eligibility demonstration to account for an action in paragraph (a) of this section that is outside of your control (e.g. change in a reference value), and that change causes your source to no longer be able to meet the criteria for the health-based compliance alternatives, your source must comply with the applicable emission limits, operating limits, and compliance requirements in subpart DDDDD within 3 years.

(c) Your revised eligibility demonstration may be reviewed by the permitting authority or EPA to verify that the demonstration meets the requirements of appendix A to this subpart and is technically sound (i.e. use of the look-up tables is appropriate or the site-specific assessment is technically valid). If you are notified by the permitting authority or EPA of any deficiencies in your submission, you will not remain eligible for the health-based compliance alternatives until the permitting authority or EPA verifies that the deficiencies are corrected.

12. What Records Must I Keep?

You must keep records of the information used in developing the eligibility demonstration for your affected source, including all of the information specified in section 8 of this appendix.

13. Definitions

The definitions in §63.7575 of subpart DDDDD apply to this appendix. Additional definitions applicable for
this appendix are as follows:

*Hazard Index (HI)* means the sum of more than one hazard quotient for multiple substances and/or multiple exposure pathways.

*Hazard Quotient (HQ)* means the ratio of the predicted media concentration of a pollutant to the media concentration at which no adverse effects are expected. For inhalation exposures, the HQ is calculated as the air concentration divided by the RfC.

*Look-up table analysis* means a risk screening analysis based on comparing the HAP or HAP-equivalent emission rate from the affected source to the appropriate maximum allowable HAP or HAP-equivalent emission rates specified in Tables 2 and 3 of this appendix.

*Reference Concentration (RfC)* means an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. It can be derived from various types of human or animal data, with uncertainty factors generally applied to reflect limitations of the data used.

*Worst-case operating conditions* means operation of an affected unit during emissions testing under the conditions that result in the highest HAP emissions or that result in the emissions stream composition (including HAP and non-HAP) that is most challenging for the control device if a control device is used. For example, worst-case conditions could include operation of an affected unit firing solid fuel likely to produce the most HAP.

**Table 1 to Appendix B of Subpart DDDDD—Emission Test Methods**

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<th>Using . . .</th>
</tr>
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<td>(1) Each subpart DDDDD emission point for which you choose to use a compliance alternative</td>
<td>Select sampling ports' location and the number of traverse points</td>
<td>Method 1 of 40 CFR part 60, appendix A.</td>
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<td>(2) Each subpart DDDDD emission point for which you choose to use a compliance alternative</td>
<td>Determine velocity and volumetric flow rate;</td>
<td>Method 2, 2F, or 2G in appendix A to 40 CFR part 60.</td>
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<td>(3) Each subpart DDDDD emission point for which you choose to use a compliance alternative</td>
<td>Conduct gas molecular weight analysis</td>
<td>Method 3A or 3B in appendix A to 40 CFR part 60.</td>
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<td>(4) Each subpart DDDDD emission point for which you choose to use a compliance alternative</td>
<td>Measure moisture content of the stack gas</td>
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<td>(5) Each subpart DDDDD emission point for which you choose to use the HCl compliance alternative</td>
<td>Measure the hydrogen chloride and chlorine emission concentrations</td>
<td>Method 26 or 26A in appendix A to 40 CFR part 60.</td>
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</table>
(6) Each subpart DDDDD emission point for which you choose to use the TSM compliance alternative

Measure the manganese emission concentration

Method 29 in appendix A to 40 CFR part 60.

(7) Each subpart DDDDD emission point for which you choose to use a compliance alternative

Convert emissions concentration to lb per MMBtu emission rates

Method 19 F-factor methodology in appendix A to part 60 of this chapter.

Table 2 to Appendix A of Subpart DDDDD—Allowable Toxicity-Weighted Emission Rate Expressed in HCl Equivalents (lbs/hr)

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Table 3 to Appendix A of Subpart DDDDD—Allowable Manganese Emission Rate (lbs/hr)

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