Memorandum

Florida Department of Environmental Protection

To:	Joseph Kahn, Division of Air Resource Management
Through:	Trina Vielhauer, Bureau of Air Regulation
From:	Jeff Koerner, New Source Review Section
Date:	July 12, 2010
Subject:	Final Air Permit No. 0990005-017-AV Okeelanta Corporation, Okeelanta Sugar Mill and Refinery New Hope Power Company, Okeelanta Cogeneration Plant Title V Air Operation Permit Renewal

The final permit for this project is attached for your approval and signature.

The attached Final Determination identifies issuance of the draft/proposed Title V air operation permit and summarizes the publication and comment process. Only minor corrections and clarifications were made in response to comments from the applicant.

I recommend your approval of the attached final permit for this project.

Attachments

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Okeelanta Corporation
New Hope Power Company
21250 U.S. Highway 27 South
South Bay, Florida 33493

Permit No. 0990005-017-AV
Title V Air Operation Permit Renewal
Okeelanta Sugar Mill and Refinery
Okeelanta Cogeneration Plant

Authorized Representative:
Mr. Ricardo Lima, V.P. and General Manager

Palm Beach County, Florida

Enclosed is the final permit package to renew the Title V air operation permit for the existing facility, which consists of Okeelanta Corporation's Okeelanta Sugar Mill and Refinery and New Hope Power Company's Okeelanta Cogeneration Plant. The existing facility is located in Palm Beach County at 21250 U.S. Highway 27 South in South Bay, Florida. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

Jeffery F. Koerner

For Trina Vielhauer, Chief
Bureau of Air Regulation

TLV/jfk

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Permit and Final Determination), 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. Ricardo Lima, Okeelanta Corporation (ricardo_lima@floridacrystals.com)
Mr. Matthew Capone, Florida Crystals (matthew_capone@floridacrystals.com)
Mr. David Buff, Golder Associates (dbuff@golder.com)
Mr. Ajaya Satyal, DEP South District Office (ajaya.satyal@dep.state.fl.us)
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Ms. Barbara Friday, DEP BAR for posting with U.S. EPA Region 4 (barbara.friday@dep.state.fl.us)
Ms. Victoria Gibson, DEP BAR for Reading File (victoria.gibson@dep.state.fl.us)

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.

Barbara J. Friday 7/16/10
(Clerk) (Date)

Permit No. 0990005-017-AV

Renewal of Permit No. 0990005-012-AV

Okeelanta Corporation (ARMS Facility ID No. 0990005)
New Hope Power Company (ARMS Facility ID No. 0990332)

1. GENERAL INFORMATION

Facility Description and Location

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 existing facility is located in Palm Beach County at 21250 U.S. Highway 27 South, South Bay, Florida. The adjacent plants are 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; one 211 MMBtu per hour industrial boiler; 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.

State Regulations

The facility is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.), which authorize the Department of Environmental Protection (Department) to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). The facility is subject to applicable portions of Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C. The specific applicable regulations are summarized under the corresponding section for the emissions units.

Federal Regulations

The Environmental Protection Agency establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 identifies New Source Performance Standards (NSPS) for a variety of industrial activities. Part 61 specifies the National Emissions Standards for Hazardous Air Pollutant (NESHAP) based on specific pollutants. Part 63 identifies NESHAP based on the Maximum Achievable Control Technology (MACT) for given source categories. The Department adopts these federal regulations in Rule 62-204.800, F.A.C. The specific applicable regulations are summarized under the corresponding section for the emissions units.

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 213, F.A.C.
- The facility is a major stationary source of air pollution in accordance with Rule 62-212.400(PSD), 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 megawatts (MW) of steam-generated electrical power. [Site Certification No. PA 04-46]
- Existing units are subject to the following NSPS in Part 60 of Title 40, the Code of Federal Regulations (CFR): Subpart A (General Provisions), Subpart Db (Industrial-Commercial-Institutional Steam Generating Units) and Subpart Dc (Small Industrial-Commercial-Institutional Steam Generating Units).
- No units are currently subject to any NESHAP in 40 CFR 63. *{Permitting Note: NESHAP Subpart DDDDD (Industrial Boilers) was vacated and remanded to EPA for reconsideration.}*

Glossary of Common Terms

Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of this permit.

Regulated Emissions Units

ARMS ID No. 0990005 – Okeelanta Corporation

EU No.	Emissions Unit Description	Process Area
014	Boiler No. 16	Sugar Mill
018	Central Vacuum System	Transshipment Facility
019	Sugar packaging Lines 0-9, including 8A and 8B	Transshipment Facility
020	Sugar Grinder/Hopper	Transshipment Facility
021	Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1	Sugar Refinery
022	Central Dust Collection System No. 2 with Rotoclone No. 2	Sugar Refinery
023	Cooler No. 1 with Rotoclone No. 3	Sugar Refinery
024	Cooler No. 2 with Rotoclone No.4	Sugar Refinery
025	Fluidized Bed Dryer/Cooler with Baghouse	Sugar Refinery
030	Sugar Silos Nos. 1, 2, and 3	Transshipment Facility
031	Railcar Sugar Unloading Receiver 1	Transshipment Facility
032	Railcar Sugar Unloading Receiver 2	Transshipment Facility
034	Bulk Load-Out Operation	Sugar Refinery
035	Transfer Bulk Load-Out Operation	Sugar Refinery
043	Sugar Refinery Alcohol Usage	Sugar Refinery
045	Powdered Sugar Dryer/Cooler, Packaging Line 8A And 8B	Transshipment Facility
046	Powdered Sugar Hopper	Transshipment Facility
047	Sugar packaging Lines 12 and 13	Transshipment Facility
048	Paint Booth	Okeelanta Shop
049	Sugar Packaging Line 14	Transshipment Facility

{Permitting Note: Okeelanta Corporation's sugar mill boilers (EU-001 - EU-013) have been permanently shutdown.}

ARMS ID No. 0990332 – New Hope Power Company

EU No.	Emissions Unit Description	Process Area
001	Cogeneration Boiler A	Cogeneration Plant
002	Cogeneration Boiler B	Cogeneration Plant
003	Cogeneration Boiler C	Cogeneration Plant
004	Cogeneration Plant - Materials Handling and Storage	Cogeneration Plant

Unregulated and/or Insignificant Emissions Units and/or Activities

ARMS ID No. 0990005 – Okeelanta Corporation

EU No.	Emissions Unit Description	Process Area
015	Fuel Storage Tank	Sugar Mill

EU No.	Emissions Unit Description	Process Area
016	Fuel Storage Tank	Sugar Mill
017	Fuel Storage Tank	Sugar Mill
033	Sugar Refinery Miscellaneous Support Equipment	Sugar Refinery
036	Shop Operations	Sugar Mill
037	Sugar Mill Boiler House	Sugar Mill
038	Sugarcane Dumping Area	Sugar Mill
039	Sugarcane Processing Facility	Sugar Mill
040	Fuel Farm	Sugar Mill
041	Potable Water System	Sugar Mill
042	Sewer Plant	Sugar Mill
044	Okeelanta Facility - Miscellaneous Unregulated Activities	Okeelanta Facility
050	Transshipment Facility, Miscellaneous Support Equipment	Transshipment Facility

ARMS ID No. 0990332 – New Hope Power Company

EU No.	Emissions Unit Description	Process Area
005	Cogeneration Plant – Miscellaneous Support Equipment	Cogeneration Plant

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 (NO_X), sulfur dioxide (SO_2), particulate matter (PM); particulate matter with a mean particle diameter of 10 microns or less (PM_{10}), 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); 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.

Brief Project Description

The purpose of this project is to revise and renew the Title V air operation permit (Permit No. 0990005-012-AV) for the sugar mill, refinery and transshipment facilities operated by the Okeelanta Corporation as well as the cogeneration plant operated by New Hope Power Company. The renewed permit incorporates the applicable requirements of the following recent air construction permits:

- Permit No. 0990332-016-AC (PSD-FL-196O), which revised the heat input rates for the cogeneration boilers;
- Permit No. Project No. 0990332-017-AC (PSD-FL-196P), which revised the electrical power generating capacity for the cogeneration boilers;
- Permit No. 0990005-015-AC, which modified the paint spray booth;
- Permit No. 0990005-016-AC, which is an air construction permit processed concurrently with the Title V permit to revise several miscellaneous underlying air construction permit conditions;
- Permit No. 0990005-018-AC, which restricts Boiler 16 to a 10% annual capacity factor;

- Permit Nos. 0990005-019-AC and 0990005-023-AC, which modified the transshipment facility; and
- Permit No. 0990005-021-AC, which modified the sugar mill refinery.

In addition, the renewed permit will:

- Update control equipment parameters for equipment in the sugar refinery (EU-021, 022, 023 and 024) based on the installed equipment;
- Update the Ash Management Plan, the Fuel Management Plan and the Operation and Maintenance Plan;
- Remove obsolete references to coal storage and handling for the cogeneration plant;
- Update the parametric ranges for the Rotoclones (EU-021, 022, 023 and 024) based on installed equipment;
- Clarify that EUs 003 through 013 have been permanently shutdown;
- Add a Compliance Assurance Monitoring Plan for affected units; and
- Add a Compliance Plan for affected units.

Processing Schedule

04/25/05 Received application to renew Title V air operation permit;

05/23/05 Received CAM plan;

06/07/05 Received notification that the cogeneration boilers and Boiler 16 were subject to NESHAP Subpart DDDDD provisions in 40 CFR 63;

12/19/05 Received additional information including a revised CAM plan;

05/26/06 Received revised Title V application to incorporate the applicable conditions of recently issued Permit No. 0990005-018-AC, which restricts Boiler 16 to a 10% annual capacity factor;

10/19/06 Received additional information on Boiler 16;

10/20/06 Received additional information on applicability of acid rain provisions to cogeneration boilers;

01/11/07 Received revised Title V application to incorporate the applicable conditions of recently issued Permit No. 0990005-019-AC, which modified the transshipment facility;

02/13/07 Received additional information including the 65 MW steam turbine-electrical generator and ash handling;

05/01/07 Received additional information on ESP parameters making application complete;

05/03/07 Issued initial draft permit package, which was never publicly noticed; and

03/12/10 Received supplemental application, which updated fuel and ash management plans, updated the CAM Plan, updated the Compliance Plan and requested several minor air construction permit revisions.

During the period between the first revised draft permit package and the supplemental application, the cogeneration boilers had compliance issues with opacity and carbon monoxide. The facility entered into Settlement Agreements with the Department and the compliance issued for the cogeneration boilers have been resolved.

2. CAM APPLICABILITY

A compliance assurance monitoring (CAM) plan specifies methods for monitoring critical control equipment parameters to provide assurance that the emissions standards of the permit are being continually met. In general, a CAM Plan is required for each emissions unit that: has a specific and enforceable emissions standard for a given pollutant; employs an add-on control device to achieve the specific standard; and, if not for the control device, would emit a major amount of the given pollutant. A CAM plan is not required for an emissions unit:

that demonstrates compliance with a continuous emissions monitoring system (CEMS); for which the control device is considered an integral part of the process and returns product or an intermediate product to the process for reuse; or is subject only to an opacity standard for regulating particulate matter.

Table 3A summarizes the CAM applicability for each active regulated emissions unit with an air pollution control device. Many of the emissions units are small sources of particulate matter, which capture and collect sugar at the sugar refinery or the sugar transshipment plants. For most cases, the emissions units are only regulated by an opacity standard for which a CAM plan is not required. Several of these units are considered integral parts of the process and return sugar for reuse in the process. In summary, a CAM plan is required for the three cogeneration boilers that control particulate matter with an electrostatic precipitator (ESP). See Table 3A on following page.

Cogeneration Boilers

New Hope Power Company's Okeelanta Cogeneration Plant (Facility ID No. 0990332) operates Cogeneration Boilers A (EU 001), B (EU 002) and C (EU 003). Each cogeneration boiler has the following add-on control equipment: multi-cyclone dust collectors followed by an ESP to reduce PM/PM_{10} emissions; a selective non-catalytic reduction (SNCR) system to reduce NO_X emissions; and an activated carbon injection (ACI) system to reduce potential mercury emissions. Each of these pollutants could be subject to a CAM plan because there is an enforceable emissions standard and an add-on control device. However, uncontrolled mercury emissions will not be emitted in a major amount prior to control and compliance with the NO_X emissions standard must be continuously demonstrated by CEMS data. Therefore, a CAM plan is only required for PM/PM_{10} emissions.

Based on the information available for the ESP, the following parameters and ranges will be established as the CAM excursion levels.

- The permittee must continuously monitor and record opacity data using the existing continuous opacity monitoring system (COMS).
- An excursion is any 1-hour average of 15% opacity or more. An alarm shall alert the operator. An excursion requires documentation, investigation, and corrective action.
- Corrective actions may include: adjusting the power to each ESP field; resetting the rapper frequency; adjusting the fuel feed rate and over-fire air system; firing supplemental natural gas or distillate oil; etc.

The CAM plan is included in Appendix CM of Section 4 of the Title V air operation permit.

3. COGENERATION PLANT

Process Description

Cogeneration Boilers A (EU-001), B (EU-002) and C (EU-003) are each spreader stoker boilers 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 (605 MMBtu per hour) and distillate oil (490 MMBtu per hour). Pollution control equipment includes low-NO_X 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, SO_2, 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.

The cogeneration plant also includes:

- Material handling and storage operations (EU-004) such as unloading operations, stockpiles, transfer operations, conveyors, screens, crushers, hoppers, silos and storage tanks. This unit is subject to the conditions regarding the control of particulate matter from silos as well as fugitive dust from the storage and handling of biomass.

Table 3A. Summary of CAM Applicability, Active Regulated Emissions Units with Add-on Control Equipment

EU No.	Description	Control	Pollutant	Standard	Major?	Integral?	CEMS?	CAM?
ARMS ID No. 0990005 - Okeelanta Corporation Sugar Mill and Refinery								
014	Mill/Refinery Boiler No. 16	FGR	NO_X	0.20 lb/MMBtu	No	---	---	No
018	Central Vacuum System	Baghouse	PM	5% opacity (only)	---	---	---	No
019	Sugar Packaging Lines 0-9, including 8A and 8B	Baghouse	PM	5% opacity (only)	---	---	---	No
020	Sugar Grinder/Hopper	Baghouse	PM	5% opacity (only)	---	---	---	No
021	Rotary Dryer, Central Dust Collector 1	Rotoclone 1	PM	5% opacity (only)	---	---	---	No
022	Central Dust Collector 2	Rotoclone 2	PM	5% opacity (only)	---	---	---	No
023	Cooler 1	Rotoclone 3	PM	5% opacity (only)	---	---	---	No
024	Cooler 2	Rotoclone 4	PM	5% opacity (only)	---	---	---	No
025	Fluidized Bed Dryer/Cooler	Baghouse	PM	5% opacity (only)	---	---	---	No
030	Sugar Silos 1, 2, And 3	Baghouse	PM	5% opacity (only)	---	---	---	No
031	Railcar Sugar Unloading Receiver 1	Baghouse	PM	5% opacity (only)	---	---	---	No
032	Railcar Sugar Unloading Receiver 2	Baghouse	PM	5% opacity (only)	---	---	---	No
045	Powdered sugar dryer/cooler, Packaging Line 8A and 8B	Baghouse	PM	5% opacity (only)	---	---	---	No
046	Powdered Sugar Hopper	Baghouse	PM	5% opacity (only)	---	---	---	No
047	Sugar packaging Lines 12 and 13	Baghouse	PM	5% opacity (only)	---	---	---	No
048	Paint Booth for Okeelanta Shop	Paint filter	PM	20% opacity (only)	---	---	---	No
		None	VOC	---	---	---	---	No
049	Sugar packaging Line 14	Baghouse	PM	5% opacity (only)	---	---	---	No
ARMS ID No. 0990332 - New Hope Power Company Cogeneration Plant								
001 002 003	Cogeneration Boiler A Cogeneration Boiler B Cogeneration Boiler C	ESP	PM	0.03 lb/MMBtu	Yes	No	No	**Yes**
		SNCR	NOx	0.15 lb/MMBtu	Yes	No	Yes	No
		ACI	Hg	5.4×10^{-06}	No	---	---	No
004	Materials Handling/Storage	None	PM	---	---	---	---	No
	Fly Ash Silo	Baghouse	PM	5% opacity (only)	---	---	---	No
	Activated Carbon Silo	Baghouse	PM	5% opacity (only)	---	---	---	No

Notes:

a. ACI means activated carbon injection. ESP means electrostatic precipitator. FGR means flue gas recirculation. SNCR means selective non-catalytic reduction.

b. In the above table, the review proceeds from left to right and stops once CAM is determined to be "not applicable".

c. CAM is not required for units that are subject only to an opacity standard.

- Miscellaneous unregulated activities (EU-005) such as boiler drum blow-down tank, diesel fire pump engine and tank, propane tank, hydrogen sulfide degasifier, distillate oil tank, oil/water separators, sodium hydroxide tank, wastewater neutralization tank, cold cleaning devices (parts washers), and sulfuric acid storage and distribution systems. This unit consists of both unregulated and insignificant activities.
- Miscellaneous support equipment (EU-006), such as a nominal 75 MW steam turbine-electrical generator, a nominal 65 MW steam turbine-electrical generator, condensers, two cooling towers, a switchyard, etc. This unit is subject only to generally applicable requirements and consists of both unregulated and insignificant activities.

Specific State Regulations

Rule 62-212.400 (PSD), F.A.C.: The cogeneration boilers were constructed in accordance with Permit No. PSD-FL-196 to satisfy the PSD preconstruction review requirements. Each cogeneration boiler is subject to the following BACT determinations for CO, F, NO_X, Pb, PM/PM_{10}, SAM, SO_2 and VOC.

<table>
<tr><th rowspan="2">Pollutant</th><th colspan="3">BACT Standards for Each Cogeneration Boiler</th></tr>
<tr><th>Averaging Period</th><th>lb/MMBtu</th><th>lb/hr</th></tr>
<tr><td rowspan="2">Carbon Monoxide (CO)
Based on "good combustion practices".</td><td>30-day rolling CEMS avg.</td><td>0.50</td><td rowspan="2">380.0</td></tr>
<tr><td>12-month rolling CEMS avg.</td><td>0.35</td></tr>
<tr><td>Nitrogen Oxides (NO_X)
Based on SNCR.</td><td>30-day rolling CEMS avg.</td><td>0.15</td><td>114.0</td></tr>
<tr><td rowspan="3">Sulfur Dioxide (SO_2)
Based on "low sulfur fuels". The SO_2 standards are also surrogate standards for sulfuric acid mist (SAM) emissions.</td><td>24-hour rolling CEMS avg.</td><td>0.20</td><td rowspan="3">152.0</td></tr>
<tr><td>30-day rolling CEMS avg.</td><td>0.10</td></tr>
<tr><td>12-month rolling CEMS avg.</td><td>0.06</td></tr>
<tr><td>Opacity
Based on mechanical dust collectors and ESP.</td><td>6-minute block COMS average and EPA Method 9</td><td colspan="2">≤ 20% opacity, except for one 6-minute block per hour ≤ 27% opacity</td></tr>
<tr><td>Particulate Matter (PM)
Based on mechanical dust collectors and ESP.</td><td>3-run test avg.</td><td>0.026</td><td>19.8</td></tr>
<tr><td>Volatile Organic Compounds (VOC)
Based on "good combustion practices".</td><td>3-run test avg.</td><td>0.05</td><td>38.0</td></tr>
<tr><td>Lead (Pb) and Fluorides (F)
Based on "clean fuels".</td><td colspan="3">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></tr>
</table>

Material handling and storage operations (EU- 004) were constructed in accordance with Permit No. PSD-FL-196 to satisfy the PSD preconstruction review requirements for PM/PM_{10}. For the fly ash storage silo and activated carbon silo, BACT was determined to be control by a baghouse 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 must meet this equipment specification based on vendor design information. Opacity from these devices shall not exceed 5%. Fugitive dust must be controlled by enclosing, confining, watering, or adding windbreaks as necessary.

On 10/27/03, the Department issued Permit No. 0990332-016-AC (PSD-FL-196O), which revised the heat input rates for the cogeneration boilers. On 06/06/05, the Department issued Permit No. Project No. 0990332-017-AC (PSD-FL-196P), which revised the electrical power generation for the cogeneration boilers. In addition, obsolete references to coal storage and handling activities were removed. These latest permit modifications will be incorporated into the renewed Title V permit.

Rule 62-296.320(4)(c), F.A.C.: This regulation establishes requirements to control fugitive dust emissions, which will be minimized by taking the reasonable precautions described above for the material handling and storage operations (EU 004).

Rule 62-296.405(2), F.A.C.: The rule applies to fossil fuel-fired steam generators with more than 250 MMBtu per hour of heat input. The cogeneration boilers are considered "new units" under this rule, which establishes the NSPS Subpart Da standards for opacity and emissions of PM, SO_2 and NO_X. The BACT standards of Permit No. PSD-FL-196 are more stringent.

Rule 62-296.410, F.A.C.: The rule applies to carbonaceous fuel burning equipment, which is defined in Rule 62-210.200 (Definitions), F.A.C. as, "A firebox, furnace or combustion device which burns carbonaceous and fossil fuels for the primary purpose of producing steam or to heat other liquids or gases. The term includes bagasse burners, bark burners, and waste wood burners, but does not include teepee or conical wood burners or incinerators." The rule establishes opacity and PM standards for affected units. The BACT standards of Permit No. PSD-FL-196 are more stringent.

Rule 62-296.570, F.A.C.: The rule subjects major VOC- and NOx-emitting facilities to Reasonably Available Control (RACT) requirements. The BACT standards of Permit No. PSD-FL-196 are more stringent.

NSPS Provisions in 40 CFR 60

Subpart A: The cogeneration boilers are subject to the applicable general provisions in Subpart A for all units subject to an NSPS.

Subpart Da: The cogeneration boilers are subject to the applicable provisions of Subpart Da for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978. The federal provisions regulate opacity and emissions of PM, SO_2 and NO_X. Subpart Da was revised to include new requirements for PM, SO_2, NO_X and mercury for units constructed, reconstructed or modified after February 28, 2005. Permit No. 0990332-016-AC was a PSD modification that increased the heat input rates to these units, which increased the maximum hourly mass emissions rates. However, this permit was issued on October 27, 2003, which is prior to the applicability date for the new requirements. Therefore, the existing units remain subject to the requirements for units constructed prior to February 28, 2005. The boiler remains subject to the NSPS Subpart Da standards for NO_X, PM and SO_2.

Subpart Ea: Provided certain conditions are met, the cogeneration boilers are not subject to the provisions of NSPS Subpart Ea for Municipal Waste Combustors for which Construction is Commenced after December 20, 1989 and on or Before September 20, 1994. Specifically, 40 CFR 60.50a (d) states, "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." A 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." The permittee has met the above notification requirements. The Title V permit restricts municipal solid waste to less than 30% by weight as measured on a calendar quarter basis and includes appropriate recordkeeping requirements.

NESHAP Provisions in 40 CFR 63

At this time, no units are subject to any National Emissions Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR 63. NESHAP Subpart DDDDD (Industrial Boilers) was vacated and remanded to EPA for reconsideration.

Title IV Acid Rain Provisions

The cogeneration plant is currently classified as a "Qualifying Cogeneration Facility" under 40 CFR Part 72 and is exempt from the Acid Rain provisions. However, to maintain the exemption as a qualifying cogeneration facility, total electrical generation may not exceed 219,000 MWe-hours 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. The Title V permit includes recordkeeping and reporting requirement to monitor the total electrical generation.

CAM Plan

As previously mentioned, a CAM plan is required for particulate matter emissions from the cogeneration boilers. See Appendix CM in Section 4 of the Title V permit.

4. SUGAR MILL AND REFINERY - BOILER 16

Process Description

Boiler 16 (EU-014) is Babcock and Wilcox Model No. FM 120-97 package boiler with a maximum steam production rate of 150,000 pounds per hour based on a 24-hour average. The design heat release rate for this unit is greater than 70,000 BTU/hour-ft^3. The unit is fired with natural gas or distillate oil. The maximum heat input rate is 211 MMBtu per hour when firing natural gas, which is approximately 0.207 million standard cubic feet (scf) of gas per hour based on a heat content of 1020 MMBtu per million scf. The maximum heat input rate is 202 MMBtu per hour when firing very low sulfur distillate oil, which is approximately 1485 gallons per hour based on a heat content of 136 MMBtu per thousand gallons. The efficient combustion of clean fuels minimizes emissions of CO, PM/PM_{10}, SO_2 and VOC. Emissions of NO_X are reduced with low-NO_X burners and approximately 15% flue gas recirculation. Exhaust gases exit a stack that is 75 feet tall and 5.0 feet in diameter with a volumetric flow rate of 118,600 acfm at 393° F.

Specific State Regulations

Permit No. 0990005-018-AC: The boiler is regulated in accordance with this minor source air construction permit, which restricts the annual capacity factor for the combined firing of distillate oil and natural gas to less than 10% during any calendar year (184,836 MMBtu per year). The annual heat input rate shall be determined from records of the higher heating value of each authorized fuel and the actual fuel consumption for the calendar year. Each year, the annual capacity factor and annual heat input rate shall be reported with the required Annual Operating Report. The purpose of this restriction is to limit potential emissions below all PSD significant emission rates and allow the unit to avoid the continuous monitoring requirements of NSPS Subpart Db.

Rule 62-296.406 (BACT), F.A.C.: This state regulation requires a determination of BACT for PM and SO_2 emissions. For these pollutants, BACT is determined to be the firing of natural gas or No. 2 distillate oil with a maximum sulfur content of 0.05% by weight. In addition, the permit limits visible emissions from the boiler stack to no more than 20% opacity, except for one 6-minute period per hour that does not exceed 27% opacity.

Rule 62-212.400(12) (Source obligation), F.A.C.: To avoid PSD preconstruction review, NO_X emissions shall not exceed 0.20 lb/MMBtu (42.2 lb/hour) when firing natural gas based on the average of three test runs and 0.20 lb/MMBtu (40.4 lb/hour) when firing distillate oil based on the average of three test runs. Compliance is based on stack testing.

Specific Federal Regulations

NSPS Subpart Db: The boiler is subject to the applicable requirements of this federal regulation for Industrial-Commercial-Institutional Steam Generating Units. However, the boiler is now permitted to fire only natural gas and distillate oil (≤ 0.05% sulfur by weight) with an annual capacity factor of no more than 10%. Based on these restrictions, there are no applicable standards for particulate matter or nitrogen oxides. However, since the unit is restricted to the firing natural gas or low sulfur distillate oil (≤ 0.30% sulfur by weight), there are few requirements for this limited use boiler.

- 40 CFR 60.42b limits SO_2 emissions by the firing of low sulfur distillate oil (≤ 0.3% sulfur by weight).

- 40 CFR 60.43b limits PM emissions by the firing of low sulfur distillate oil (≤ 0.3% sulfur by weight).
- 40 CFR 60.44b does not establish a NO_X standard for such limited use units.
- 40 CFR 60.45b, 40 CFR 60.46b and 40 CFR 60.47b and 40 CFR 60.49b allow allows the permittee to demonstrate compliance with the fuel sulfur limit by maintaining fuel receipts.

5. SUGAR REFINERY

Process Description

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 LÜB-beck (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, which exhausts 89 feet above grade. Wet Rotoclone No. 1 also controls dust from two specialty sugar conveyors that transfer sugar products during production with the rotary dryer and coolers. 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.

Central Dust Collection System No. 2 (EU-022) is used to control dust emissions from several miscellaneous sources including: bucket elevator #10, #16 and #43; the silo scale; belt conveyors #11, #16, #18, #19 A and B; screw conveyors #20, #26, #28, #40, #45, #Q1, #Q2, #S1 and #S2; the packing room bins; the bulk curing bins #1 through #8; and the Sweco shaker screen. The system is controlled by Rotoclone No. 2, which exhausts 86 feet above grade. Rotoclone No. 2 operates when either the Fluidized Bed Dryer or the Rotary Dryer are operating.

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. The sugar refinery is regulated in accordance with air construction Permit No. 0990005-021-AC.

Controls

The Fluidized Bed Dryer (EU-025) controls particulate emissions with a baghouse control system meeting the following specifications: a design exhaust flow rate of 70,620 acfm; a filtering area of 9041 ft^2; and an air-to-cloth ration of 7.81 acfm/ft^2. The design PM/PM_{10} control efficiency is 99.8%.

Rotoclones meeting the following specifications are used to control particulate emissions from the two Central Dust Collection Systems (EU 021 and 022) and the two Coolers (EU 023 and 024).

EU No.	Description	Control Type	Design Flow Rates acfm	Water Injection Rate (gpm, min.)	Control Efficiency	
					PM	PM_{10}
021	Rotary Dryer, Central Dust Collection System No. 1	Rotoclone No. 1	15,000	2	99.9%	99%
022	Central Dust Collection System No. 2	Rotoclone No. 2	15,000	2	99.9%	99%
023	Cooler No. 1	Rotoclone No. 3	15,000	2	99.9%	99%
024	Cooler No. 2	Rotoclone No. 4	15,000	2	99.9%	99%

Capacities

The hours of operation for the sugar refinery are not restricted (8760 hours/year). Equipment at the sugar refinery shall be limited to the following maximum capacities:

- Total refined sugar production (Fluidized Bed Dryer (EU-025), Rotary Dryer (EU-021) and Cooler No. 1 (EU-023) shall not exceed 490,000 tons during any consecutive 52-week period.
- The Rotary Dryer (EU-021) and Cooler No. 1 (EU-023) shall not process more than 130,000 tons during any consecutive 52-week period.
- The Bulk Load-Out Operation (EU-034) shall not process more than 139,000 tons of refined sugar during any consecutive 52-week period.
- 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.
- Sugar refinery alcohol usage (EU-043) from the sugar refinery shall not exceed 78,040 pounds during any consecutive 52-week period.

Emissions Standards

As determined by EPA Method 9, visible emissions from the control device exhausts of the following emissions units shall not exceed 5% opacity: Rotary Dryer, Central Dust Collection No. 1 (EU-021); Central Dust Collection System No. 2 (EU-022); Cooler No. 1 (EU-023); Cooler No. 2 (EU-024); and Fluidized Bed Dryer

(EU-25). Visible emissions from the Bulk Load-Out Operation (EU-034) and the Transfer Bulk Load-Out Station (EU-035) shall not exceed 20% opacity. During each federal fiscal year (October 1st to September 30th), each Rotoclone and baghouse exhaust point shall be tested to demonstrate compliance with the specified opacity standard.

6. 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 4600 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 13 packaging lines, which are controlled by baghouse systems (Lines 0-8A and 8B-9 (EU-019), Lines 12 and 13 (EU-047) and Line 14 (EU-049)). 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 and packaging Line 14 vents to a dedicated baghouse (EU-049). Sugar is metered from surge bins above the packaging lines for processing into a variety of packages and containers for wholesale and retail distribution.

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.

Controls

Each of the following emissions units are 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.

ID	Emission Unit Description	Baghouse Specification [a] grains/scf	Exhaust Rate scfm	Stack/Vent Height Feet	Maximum Emissions [b]	
					lb/hour	tons/year
018	Central vacuum system No. 1	0.01	280	8	0.024	0.11
019	Sugar packaging Lines 0-9, including 8A and 8B	0.01	9869	27	0.85	3.71
020	Sugar grinder	0.0005	2961	39	0.013	0.06
030	Sugar silo No. 1 (Point #S1101)	0.02	500	65	0.086	0.38
	Sugar silo No. 2 (Point #S1102)	0.02	500	65	0.086	0.38
	Sugar silo No. 3 (Point #S1103)	0.02	500	65	0.086	0.38

ID	Emission Unit Description	Baghouse Specification [a] grains/scf	Exhaust Rate scfm	Stack/Vent Height Feet	Maximum Emissions [b]	
					lb/hour	tons/year
031	Railcar unloading receiver No. 1	0.02	615	5	0.11	0.46
032	Railcar unloading receiver No. 2	0.02	615	5	0.11	0.46
045	Powdered sugar dryer/cooler, packaging Lines 8A and 8B	0.01	8640	48	0.74	3.24
046	Powdered sugar hopper	0.01	1728	42	0.15	0.68
047	Sugar packaging Lines 12 and 13	0.01	3629	48	0.49	2.16
049	Sugar packaging Line 14	0.02	2212	9	0.38	1.66
					Total	13.68

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 8760 hours of operation per year. These rates are not enforceable emissions standards.

Capacity

The maximum sugar packaging rate is 1300 tons per day. The hours of operation of are not limited (8760 hours per year).

Emissions Standards

As determined by EPA Method 9 observations, visible emissions from each baghouse exhaust point shall not exceed 5% opacity. During each federal fiscal year (October 1st to September 30th), each baghouse exhaust point shall be tested to demonstrate compliance with the specified opacity standard.

7. DISTILLATE OIL STORAGE TANKS

Concurrent Permit No. 0990005-016-AC includes a new permit condition explaining the applicability of the NSPS Subpart Kb provisions to fuel tanks. In short, NSPS Subpart Kb does not apply to any fuel storage tanks at the New Hope Power Company's Okeelanta Cogeneration Plant or the Okeelanta Corporation's Sugar Mill and Refinery.

8. PAINT SPRAY BOOTH IN THE OKEELANTA SHOP

Description and Controls

The paint spray booth (EU-048) is the drive-through model of the Crossflo truck spray booth manufactured by AFC, Inc. (Model Number TSD6036). Paint is applied to agricultural equipment, trailers, and other vehicles. Paint will be applied by one of two methods: compressed air spray gun or an airless paint sprayer. The compressed air spray gun will use house air within a pressure range of 60 to 80 pounds per square inch (psi). The airless paint sprayer will operate at a pressure of approximately 3,200 psi. The paint booth has a design exhaust flow rate of 45,500 acfm. There are two exhaust stacks for the paint spray booth. Each stack is 25.7 feet tall and 4-foot diameter. The permittee shall operate and maintain functional glass fiber paint arrestor pads to remove paint overspray from the exhaust.

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_{10}). It is primarily regulated by minor source air construction Permit No. 0990005-015-AC.

Capacity

The hours of operation are not limited (8760 hours/year). The maximum throughput rate of paint and thinner shall not exceed 4950 gallons in any consecutive 12 months.

Emissions Standards

VOC emissions from the paint spray booth 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. 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 VOC. Compliance shall be demonstrated by maintaining material and usage records.

Pursuant to Rule 62-296.320, F.A.C., visible emissions from the paint spray booth shall not exceed 20% opacity.

9. COMPLIANCE PLAN

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

Mill Boiler No. 16 (EU-014)

Permit No. 0990005-018-AC

1. *Deviation*: As required by Condition III.A.9 of the permit, the initial compliance tests for NO_X and opacity were not conducted by April 12, 2007.

   Underlying Cause: Boiler 16 has not operated since the permit was issued on April 12, 2006. The last day of operation was March 16, 2004. The permittee has no immediate plans to operate Boiler 16.

   Plan: The permittee shall conduct each required compliance test within 60 days of initially operating the boiler on a particular fuel type.

2. *Deviation*: As required by Condition III.A.10 of the permit, the initial sampling and analysis of distillate oil in the associated tanks for fuel sulfur was not conducted concurrently with the initial emissions compliance tests.

   Underlying Cause: Boiler 16 has not operated since March 16, 2004. No oil has been delivered or fired since this time.

   Plan: The permittee shall conduct the required sampling/analysis and provide the results within 30 days after commencing operation of Boiler 16 on distillate oil.

3. *Deviation*: As previously reported in the Annual Statements of Compliance, 40 CFR 60.49b(q) requires quarterly reporting of the annual capacity factor and the hours of operation during each quarter. However, when the permit was issued, Boiler 16 had already been shut down for a year. Therefore, Boiler 16 was already subject to the 60-day advance notification of startup required by Rule 62-210.300(5), F.A.C. for shutdown units.

   Underlying Cause: Boiler 16 did not operate and the annual capacity factor and hours of operation were zero.

   Plan: The permittee shall provide written notification of intent to startup Boiler 16 at least 60 days before the intended startup and in accordance with the requirements of Rule 62-210.300(5), F.A.C. Pursuant to 40 CFR 60.49b(q), the permittee shall begin quarterly reporting of the annual capacity factor and hours of operation for the first quarter in which Boiler 16 begins operation.

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)

Rule 62-297.310(2), F.A.C.

Deviation: If a compliance test is conducted below permitted capacity (90% to 100% of maximum operation rate allowed by the permit), this rules limits subsequent operation to 110% of the tested 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.

Underlying Cause: On September 30, 2009, a compliance test was conducted to determine opacity with the unit operating at 608 tons/day, which is below permitted capacity (1300 tons/day). Subsequently, the unit was operated above 110% of the tested rate. On February 15, 2010, the permittee conducted another compliance test at 822 tons/day, which is still below permitted capacity and limits subsequent operation to 904.5 tons/day.

Plan: As necessary, the permittee shall conduct additional opacity tests to remain in compliance with the current tested rate demonstrating compliance with the standard.

10. CONCLUSION

Based on reasonable assurances of compliance provided by the applicant and the Responsible Official's certification of compliance, the Department intends to issue a Title V Air Operation Permit under the provisions of Chapter 403, F.S. and Chapters 62-4, 62-210, 62-213, F.A.C. The permit authorizes operation of 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.

PERMITTEE

Okeelanta Corporation
New Hope Power Company
21250 U.S. Highway 27 South
South Bay, Florida 33493

PERMITTING AUTHORITY

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

PROJECT

Permit No. 0990005-017-AV
Okeelanta Sugar Mill and Refinery
Okeelanta Cogeneration Plant

The purpose of this project is to revise and renew the Title V air operation permit for the above referenced facility.

NOTICE AND PUBLICATION

The Department distributed a Draft/Proposed Title V Air Operation Permit Renewal package on April 19, 2010. The applicant published the Public Notice of Intent to Issue a Title V Air Operation Permit Renewal in The Palm Beach Post on May 23, 2010. The Department received the proof of publication on May 26, 2010.

COMMENTS

No comments on the draft/proposed permit were received from the EPA Region 4 Office, the Palm Beach County Health Department or the public. The applicant submitted the following comments requesting corrections and clarifications.

Draft/Proposed permit No. 0990005-017-AV

Section 1, Regulatory Categories: Clarify that Boiler 16 may be subject to future NESHAP Subpart DDDDD provisions; however, the cogeneration boilers are considered electric utility boilers and not industrial boilers. *Response*: The correction was made.

Section 3, Subsection A, Cogeneration Boilers

Condition 11: Clarify the second sentence as follows, "In addition to the primary fuels, ~~E~~each boiler may startup ~~solely~~ on natural gas or distillate oil." *Response*: The clarification was made.

Condition 13.g: Since Condition 19.e includes Method 30B for mercury testing, correct Condition 13.g by adding Method 30B to be consistent. *Response*: The correction was made.

Condition 17.c.1): Correct this condition to reflect the changes in concurrent Permit No. 0990005-016-AC, "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 ~~operating temperature recommended by the~~ ESP ~~manufacturer is maintained (approximately 340° F to 350 ° F), it shall be~~ is placed on line, ~~and~~ the boiler shall comply with the specified opacity standard." *Response*: The correction was made.

Condition 18.a.3): Correct this condition to reflect the changes in concurrent Permit No. 0990005-016-AC, "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 ~~operating temperature recommended by the ESP manufacturer is maintained (approximately 340° F to 350 ° F), the~~ ESP is placed in service~~.~~, the boiler shall comply with the specified opacity standard. The ESP shall be on line and functioning properly before firing any biomass. *Response*: The correction was made.

Conditions 20.a.3) and 20.b: Correct the conditions to reflect the changes made in concurrent Permit No. 0990005-016-AC that identify the installed CO_2 monitor instead of an O_2 monitor. *Response*: The correction was made.

Section 3, Subsection B, Material Handling and Storage operations – Cogeneration Plant

Condition 8: Clarify this condition as follows, "Due to infrequent use, the baghouse vent for the fly ash silo shall be tested during any federal fiscal year in which the fly ash silo operates more than 400 hours per year, 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 per year." *Response*: This is the intent of this condition and the clarification was made.

Section 3, Subsection C, Boiler 16 – Sugar Mill/Refinery

Under Emissions Unit Description: NESHAP Subpart DDDDD is listed as a primary applicable requirement. Please clarify that this regulation has been vacated and remanded to EPA for reconsideration. *Response*: The clarification was made.

Section 3, Subsection D, Sugar Refinery

Miscellaneous Process Descriptions: Correct the stated capacity of the Fluidized Bed Dryer/Cooler from 1200 to 1350 tons per day. *Response*: The correction was made.

Condition 5.b.2): Clarify that Cooler No. 2 (EU-024) is Cooler No. 2 (with Rotoclone No. 4, EU-024). *Response*: The clarification was made.

Section 3, Subsection F, Distillate Oil Storage Tanks

Condition 1: Correct this condition to reflect the changes in concurrent Permit No. 0990005-016-AC, which state that NSPS Subpart Kb does not apply to the storage tanks. *Response*: The correction was made.

Section 4, Appendix AM, Ash Management Plan

Quality Control Measures: Request the following minor corrections and clarifications:

> 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 ~~plies~~ piles in the storage bunker. …
>
> If the fly ash is being collected in the silo, weekly fly ash grab samples are obtained ~~(also by the Chemical Technician) weekly~~ from the transfer point between the collecting fly ash chain conveyor and the bucket elevator conveyor, as ash is loaded into the silo. Additionally, grab samples of the bottom ash are obtained weekly from the bottom ash piles in the storage bunker.
>
> *Response*: The corrections and clarifications were made.

Section 4, Appendix CP, Compliance Plan

Heading, "Sugar Processing Lines 0 – 9 (EU-019)": Correct heading to, "Sugar Packaging Lines 0 – 9 (EU-019). *Response*: The correction was made.

Section 4, Appendix HI, Permit History

Emissions Units Descriptions: For EU-004, EU-005 and EU-006, correct the descriptions to be consistent with those in the body of the permit. *Response*: The corrections were made.

Section 4, Appendix SS, Summary of Standards

Emissions Units Descriptions: For EU-005 and EU-006, correct the descriptions to be consistent with those in the body of the permit. *Response*: The corrections were made.

Permit Subsection 3D – Sugar Refinery: Correct descriptions of the emissions units and permitted capacities to be consistent with underlying Permit No. 0990005-021-AC. *Response*: The corrections were made.

Section 4, Appendix UI, Unregulated and Insignificant Emissions Units and/or Activities

On March 15, 2010, Okeelanta Corporation notified the Department of the following insignificant activities: a 300 hp gas-fired boiler and a specialty sugar receiving bin with dust collector (refined sugar warehouse #3). Identify these insignificant emissions units on Page UI-3. *Response*: The Department identified these units under EU-037, but moved these to Page UI-3. The equipment is identified as insignificant activities.

CONCLUSION

The final action of the Department is to issue the permit with the corrections and clarifications identified above.

TITLE V AIR OPERATION PERMIT

Permit No. 0990005-017-AV
Renewal of Permit No. 0990005-012-AV

APPLICANT

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

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

21250 U.S. Highway 27 South
South Bay, Palm Beach County, Florida 33493

Permitting Authority

State of Florida
Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
New Source Review Section
2600 Blair Stone Road
Mail Station #5505
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
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Compliance Authority

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Permit No. 0990005-017-AV
Okeelanta Corporation
Facility ID No. 0990005
New Hope Power Company
Facility ID No. 0990332
Title V Air Operation Permit
Palm Beach County, Florida

The purpose of this permit is to renew the Title V air operation permit 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, 524.90 km East and 2940.10 km North (Latitude 26° 35' 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: July 17, 2010
Renewal Application Due Date: July 16, 2015
Expiration Date: December 3, 2014

Joseph Kahn, Director
Division of Air Resource 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 transsshipment 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; one 211 MMBtu per hour industrial boiler; 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 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), Subpart Da (Electric Utility Steam Generating Units) and Subpart Db (Industrial-Commercial-Institutional Steam Generating Units).
- No units are currently subject to any National Emissions Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR 63. *{Permitting Note: NESHAP Subpart DDDDD (Industrial Boilers) was vacated and remanded to EPA for reconsideration.}*

Appendix SS provides a summary of the applicable requirements for each regulated unit.

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 (NO_X), sulfur dioxide (SO_2), particulate matter (PM); particulate matter with a mean particle diameter of 10 microns or less (PM_{10}), 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 (H_2S); total reduced sulfur (TRS), including H_2S; reduced sulfur compounds, including H_2S; 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

EU No.	Emissions Unit Description	Process Area
014	Boiler No. 16	Sugar Mill and Refinery
018	Central Vacuum System	Transshipment Facility
019	Sugar Packaging Lines 0-9, including 8A and 8B	Transshipment Facility
020	Sugar Grinder/Hopper	Transshipment Facility
021	Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1	Sugar Refinery
022	Central Dust Collection System No. 2 with Rotoclone No. 2	Sugar Refinery
023	Cooler No. 1 with Rotoclone No. 3	Sugar Refinery
024	Cooler No. 2 with Rotoclone No. 4	Sugar Refinery
025	Fluidized Bed Dryer/Cooler with Baghouse	Sugar Refinery
030	Sugar Silos Nos. 1, 2, and 3	Transshipment Facility
031	Railcar Sugar Unloading Receiver 1	Transshipment Facility
032	Railcar Sugar Unloading Receiver 2	Transshipment Facility
034	Bulk Load-Out Operation	Sugar Refinery
035	Transfer Bulk Load-Out Operation	Sugar Refinery
043	Sugar Refinery Alcohol Usage	Sugar Refinery
045	Powdered Sugar Dryer/Cooler, Packaging Line 8A And 8B	Transshipment Facility
046	Powdered Sugar Hopper	Transshipment Facility
047	Sugar Packaging Lines 12 and 13	Transshipment Facility
048	Paint Booth	Okeelanta Shop
049	Sugar Packaging Line 14	Transshipment Facility

{Permitting Note: The original sugar mill boilers (EU-001 - EU-013) have been permanently shutdown.}

ARMS ID No. 0990332 – New Hope Power Company

EU No.	Emissions Unit Description	Process Area
001	Cogeneration Boiler A	Cogeneration Plant
002	Cogeneration Boiler B	Cogeneration Plant
003	Cogeneration Boiler C	Cogeneration Plant
004	Cogeneration Plant - Material Handling and Storage	Cogeneration Plant

Unregulated Emissions Units and/or Activities

ARMS ID No. 0990005 – Okeelanta Corporation

EU No.	Emissions Unit Description	Process Area
015	Fuel Storage Tank	Sugar Mill and Refinery

EU No.	Emissions Unit Description	Process Area
016	Fuel Storage Tank	Sugar Mill and Refinery
017	Fuel Storage Tank	Sugar Mill and Refinery
033	Sugar Refinery Miscellaneous Support Equipment	Sugar Refinery
036	Shop Operations	Sugar Mill
037	Sugar Mill Boiler House	Sugar Mill
038	Sugarcane Dumping Area	Sugar Mill
039	Sugarcane Processing Facility	Sugar Mill
040	Fuel Farm	Sugar Mill
041	Potable Water System	Sugar Mill
042	Sewer Plant	Sugar Mill
044	Okeelanta Facility - Miscellaneous Unregulated Activities	Okeelanta Facility
050	Transshipment Facility, Miscellaneous Support Equipment	Transshipment Facility

ARMS ID No. 0990332 – New Hope Power Company

EU No.	Emissions Unit Description	Process Area
005	Cogeneration Plant – Miscellaneous Support Equipment	Cogeneration Plant

Unregulated and insignificant emissions units and activities are also summarized in Appendix UI in Section 4 of this permit.

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 33902-2549. The telephone number is 239/332-6975 and the fax number is 239/332-6969. 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 Resource Section of the Department's South District Office at: 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-2549. The telephone number is 239/332-6975 and the fax number is 239/332-6969. Copies of all such documents shall also 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 (Telephone No. 561/837-5900 and Facsimile No. 561/837-5295).

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. [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% 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 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.

    Rule 62-210.700, F.A.C., cannot vary any federal NSPS or NESHAP provisions. [Rule 62-210.700(1), F.A.C.]

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, Telephone: 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.

EU No.	Emissions Unit Description (ARMS ID No. 0990332)
001 002 003	**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 (605 MMBtu per hour) and distillate oil (490 MMBtu per hour). Pollution control equipment includes low-NO_X 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 ofCO, SAM, SO_2, 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.

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, NO_X, Pb, PM/PM_{10}, SAM, SO_2, 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 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).

Specific State Regulations: Rule 62-296.405(2), F.A.C. applies to fossil fuel-fired steam generators with more than 250 MMBtu per hour of heat input. Rule 62-296.410, F.A.C. applies to carbonaceous fuel burning equipment. Rule 62-296.570, F.A.C. applies RACT to major VOC- and NOx-emitting facilities.

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 62-297.345, F.A.C. [Permit No. PSD-FL-196P; Rules 62-4.070(3) and 62-297.335, 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-NO_X natural gas burners rated for no more than 0.15 lb of NO_X 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.

   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% 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% removal of particulate matter.

   d. A selective non-catalytic reduction system designed for at least 40% 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-196P; 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, NO_X, CO_2, and SO_2 in a manner sufficient to demonstrate compliance with the standards of this permit. The opacity monitor shall be placed in the ductwork between the electrostatic precipitator and the stack or in the stack. [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% biomass, 605 MMBtu/hr when burning 100% natural gas, and 490 MMBtu/hr when burning 100% 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% 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% 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% 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.]

12. Fuel Management Plan: The permittee shall abide by the Fuel Management Plan specified in Appendix FM. [Permit No. PSD-FL-196P]

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:

Pollutant	Averaging Period	Emissions Standards per Boiler [i]	
		lb/MMBtu	lb/hr
Carbon Monoxide [a]	30-day rolling CEMS avg.	0.50	380.0
	12-month rolling CEMS avg.	0.35	
Nitrogen Oxides [b]	30-day rolling CEMS avg.	0.15	114.0
Sulfur Dioxide [c]	24-hour rolling CEMS avg.	0.20	152.0
	30-day rolling CEMS avg.	0.10	
	12-month rolling CEMS avg.	0.06	
Stack Opacity [d]	6-minute block average by COMS and EPA Method 9	≤ 20% opacity, except for one 6-minute block per hour ≤ 27% opacity	
Particulate Matter [e]	3-run test avg.	0.026	19.8
Volatile Organic Compounds [f]	3-run test avg.	0.05	38.0
Mercury [g]	3-run test avg.	5.4×10^{-06}	NA

Pollutant	Averaging Period	Emissions Standards per Boiler[i]	
		lb/MMBtu	lb/hr
Lead and Fluorides[h]	The BACT determination for lead and fluoride emissions is the use of fuels containing low levels of these compounds (bagasse, wood, distillate oil, and natural gas) and prospective removal with the fly ash by the mechanical dust collectors and electrostatic precipitators.		

a. Compliance shall be determined by data collected from the required CO CEMS in terms of "lb/MMBtu of heat input". The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and be consistent with the NO_X monitoring requirements below. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period.

b. Compliance shall be determined by data collected from the required NO_X 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 NO_X 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 SO_2 standards shall be determined by data collected from the required SO_2 CEMS in terms of "lb/MMBtu of heat input". The 24-hour average shall be determined by calculating the arithmetic average of all valid hourly emission rates for 24 successive boiler-operating hours. The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler-operating days and the requirements of 40 CFR 60.13, 60.43a, 60.46a, 60.47a, 60.48a, and 60.49a. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period. Valid SO_2 hourly averages shall not be excluded from any compliance average. 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 SO_2 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 SO_2 emissions with the firing of low sulfur fuels. For reporting purposes, sulfuric acid mist emissions shall be estimated as 6% of the total measured SO_2 emissions.}*

d. Continuous compliance with the opacity standard shall be determined by data collected from the required COMS in terms of "percent opacity" based on 6-minute block averages. Alternatively, compliance may also be determined by conducting EPA Method 9 observations. 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% opacity (6-minute average), except for one 6-minute period per hour of not more than 27% 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 PM_{10} emissions, it shall be assumed that all particulate matter emitted is PM_{10}. 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 x 10^{-05} lb/MMBtu and average fluoride emissions are expected to be 1.9 x 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% opacity except that a density of 40% 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 NO_X-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_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_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_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.

[Permit No. PSD-FL-196P; Rules 62-4.070(3), 62-210.200, and 62-210.700, F.A.C.; 40 CFR 60.8; and 40 CFR 60.46a]

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.

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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% wood materials by weight. Testing of emissions shall be conducted with each cogeneration boiler operating at permitted capacity, which is defined as a heat input rate between 684 and 760 MMBtu/hour and firing 100% biomass. If it is impracticable to test at permitted capacity, a cogeneration boiler may be tested at less than the maximum permitted capacity; in this case, subsequent operation is limited to 110 percent of the test rate until a new test is conducted. Within three days of completing a test below permitted capacity, the permittee shall provide written notification of the restricted operational capacity to the Compliance Authority. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(7)(a)9, F.A.C. and 40 CFR 60.7, 60.8]

e. *Test Methods*: 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.

EPA Method	Description
1	Selection of sample site and velocity traverses
2	Stack gas flow rate when converting concentrations to or from mass emission limits
3A	Gas analysis when needed for calculation of molecular weight or percentO_2
4	Moisture content when converting stack velocity to dry volumetric flow rate for use in converting concentrations in dry gases to or from mass emission limits
5	Particulate matter emissions
6 or 6C	Sulfur dioxide emissions
7 or 7E	Nitrogen oxide emissions
9	Visible emissions determination of opacity *{Permitting Note: Although each unit is required to monitor opacity with a COMS, visible observations may also be used to demonstrate compliance.}*
10	Carbon monoxide emissions
12	Inorganic lead emissions
19	Calculation of sulfur dioxide and nitrogen oxide emission rates
25A	Volatile organic compounds emissions *{Permitting Note: EPA Method 18 may be conducted concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. Otherwise, all emissions measured by EPA Method 25A shall be considered "volatile organic compounds".*
29	Multiple metals emissions
30B	Determination of Total Vapor Phase Mercury
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 CT of this permit. The permittee shall use CEMS and COMS data to demonstrate compliance with the emissions standards for CO, NOx, SO_2 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. <u>CEMS and COMS</u>: 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, NO_X, CO_2 (for O_2), and SO_2 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 NO_X and SO_2 CEMS shall comply with Performance Specification 2 in Appendix B of 40 CFR 60. The SO_2 reference method for the annual RATA shall be EPA Method 6 (or 6C) in Appendix A of 40 CFR 60. The NO_X reference method for the annual RATA shall be EPA Method 7 (or 7E) in Appendix A of 40 CFR 60.

        3) The CO_2 CEMS shall comply with Performance Specification 3 in Appendix B of 40 CFR 60. The CO_2 reference method for the annual RATA shall be EPA Method 3A 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 SO_2 CEMS shall express the 1-hour emission averages in terms of "lb/MMBtu of heat input". The CO_2 CEMS shall express the 1-hour emission average (CO_2 and O_2) 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. NO_X and SO_2 CEMS shall comply with NSPS Subpart Da in 40 CFR 60.

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

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

d. *Monitor Availability.* Monitor availability shall not be less than 95% in any calendar quarter. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

e. *Other Applicable Requirements*: Each CEMS shall comply with the following applicable requirements Rules 62-204.800 (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_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_X standards. Should the NO_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 (MWe-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 SO_2 emissions and the 12-month rolling total 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), and Subpart Ea (Applicability for Municipal Waste Combustors). The applicable provisions are specified in Appendices 60A, 60Da 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.

This subsection addresses the following emissions units.

EU No.	Emissions Unit Description
004	**Cogeneration Plant - Material Handling and Storage** includes unloading operations, stockpiles, transfer operations, conveyors, screens, crushers, hoppers and silos.

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.

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

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% 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% 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 1st through September 30th), 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.]

C. Boiler No. 16 - Sugar Mill/Refinery

This section of the permit addresses the following emissions unit.

EU No.	Description
014	**Boiler No. 16** is Babcock and Wilcox Model No. FM 120-97 package boiler with a maximum steam production rate of 150,000 pounds per hour (24-hour average). The design heat release rate for this unit is greater than 70,000 BTU/hour-ft^3. *Fuels*: This unit is fired with natural gas or distillate oil. *Capacity*: The heat input rate is 211 MMBtu per hour when firing natural gas, which is approximately 0.207 million cubic feet of gas per hour based on a heat content of 1020 MMBtu per million SCF. The heat input rate is 202 MMBtu per hour when firing very low sulfur distillate oil, which is approximately 1485 gallons per hour based on a heat content of 136 MMBtu per thousand gallons. *Controls*: The efficient combustion of clean fuels minimizes emissions of CO, PM/ PM_{10}, SO_2, and VOC. Emissions of NO_X are reduced with low-NO_X burners and flue gas recirculation (approximately 15%). *Stack Parameters*: Exhaust gases exit a 75' tall stack that is 5.0' in diameter at 393° F with a volumetric flow rate of 118,600 acfm.

The following describes the primary applicable requirements for the boiler.

NSPS Provisions in 40 CFR 60, incorporated by reference in Rule 62-204.800, F.A.C., including: NSPS Subpart A (General Provisions) and Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units).

Specific State Regulations, including: Rule 62-296.405(2), F.A.C. (Fossil Fuel-fired 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. (RACT for Major VOC- and NOx-Emitting Facilities).

EQUIPMENT SPECIFICATIONS

1. NOx Controls: The permittee shall tune, maintain and operate the low-NO_X burner system along with flue gas recirculation (FGR) to achieve the emissions standards specified in this permit. The burner system shall be capable of firing natural gas and distillate oil. [Permit No. 0990005-018-AC; Rule 62-4.070(3), F.A.C.]

CAPACITY, FUELS AND PERFORMANCE RESTRICTIONS

2. Authorized Fuel: The boiler shall fire only natural gas or No. 2 distillate oil with a maximum sulfur content of 0.05% by weight. [Permit No. 0990005-018-AC; Rules 62-210.200 (PTE) and 62-296.406 (BACT), F.A.C.]

3. Permitted Capacity: The maximum design heat input rates to the boiler are 211 MMBtu per hour when firing natural gas and 202 MMBtu per hour when firing distillate oil. The maximum steam production rate shall not exceed 150,000 pounds per hour based on a 24-hour block average. The boiler shall be equipped with integrating fuel flow meters to monitor the consumption of natural gas and distillate oil. The boiler shall be equipped with instruments to continuously monitor the steam production rate (pounds per hour), steam temperature (° F), and steam pressure (psig). [Permit No. 0990005-018-AC; Rule 62-210.200 (PTE), F.A.C.]

4. Restricted Operation: The hours of operation are not limited (8760 hours per year); however, the annual capacity factor for the combined firing of distillate oil and natural gas shall not exceed 10% during any calendar year. The heat input rate to the boiler shall not exceed 184,836 MMBtu per year (10% of the maximum permitted heat input rate). The annual heat input rate shall be determined from records of the higher heating value of each authorized fuel and the actual fuel consumption for the calendar year. Each

year, the annual capacity factor and annual heat input rate shall be reported with the required Annual Operating Report. *{Permitting Note: This restriction limits potential emissions below all PSD significant emission rates and allows the unit to avoid the continuous monitoring requirements of NSPS Subpart Db.}* [Permit No. 0990005-018-AC; § 60.41b (Definitions); § 60.44b (Nitrogen Oxides); Rule 62-210.200 (PTE), F.A.C.]

EMISSION LIMITING STANDARDS

5. Stack Opacity: As determined by EPA Method 9 observations, visible emissions from the boiler stack shall not exceed 20% opacity, except for one 6-minute period per hour that does not exceed 27% opacity. [Permit No. 0990005-018-AC; Rule 62-296.406(1), F.A.C.]

6. Nitrogen Oxides (NOx) Emissions: As determined by EPA Method 7E, NO_X emissions shall not exceed 0.20 lb/MMBtu (42.2 lb/hour) when firing natural gas based on the average of three test runs. As determined by EPA Method 7E, NO_X emissions shall not exceed 0.20 lb/MMBtu (40.4 lb/hour) when firing distillate oil based on the average of three test runs. [Permit No. 0990005-018-AC; Rule 62-4.070(3), F.A.C.; Rule 62-212.400(2)(g), F.A.C.]

7. Fuel Specification: The boiler shall fire only natural gas or No. 2 distillate oil with a maximum sulfur content of 0.05% sulfur by weight. Emissions of carbon monoxide (CO), particulate matter (PM/ PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC) shall be minimized by the efficient combustion of these authorized fuels. *{Permitting Note: The expected maximum CO emissions are 0.11 lb/MMBtu (natural gas or distillate oil). The expected maximum PM/PM_{10} emissions are 0.002 lb/MMBtu (natural gas) and 0.03 lb/MMBtu (distillate oil). The expected maximum SO_2 emissions are 0.001 lb/MMBtu (natural gas) and 0.05 lb/MMBtu (distillate oil). The expected maximum VOC emissions are 0.03 lb/MMBtu (natural gas or distillate oil).}* [Permit No. 0990005-018-AC; Rule 62-4.070(3), F.A.C.; Rule 62-296.406(2) and (3)]

STARTUP, SHUTDOWN, AND MALFUNCTION

8. 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) Check to ensure all the boiler doors/registers are closed.

      2) Propane supply to the gun is opened and compressed air is admitted to atomizing system.

      3) The start switch is turned on to activate the startup sequence. Once oil firing is established, minimum fire (10%) is maintained for 30 minutes on and 30 minutes off for approximately 2 hours.

      4) Continuous firing is established and steam pressure is increased to about 150 psig. Firing continues on low fire until operating pressure (350 psig) is available on the line (about 5 hours after initial firing). Atomization is changed to steam.

      5) Once consistent steam flow to user (e.g., turbo-alternator) is established, boiler controls are placed on automatic.

   b. *Shutdown Procedures.*

      1) Control is turned off and the fuel pump is shut off.

      2) The atomizing steam valve is closed. The F.D. fan is shut off.

      3) After about 3 hours, the drum level is set at maximum level.

   [Application No. 0990005-017-AV]

TESTING

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

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources

In addition, it may be necessary to perform EPA Methods 1 through 4 as part of the above test methods. These test methods are specified in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used to demonstrate compliance unless prior written approval is received from the Department. Other applicable testing requirements are included in Appendix CT of the permit. [Permit No. 0990005-018-AC; Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

10. Compliance Tests: The permittee shall conduct NO_X compliance tests within 12 months before the expiration date of the Title V operation permit. NO_X emissions shall be reported in terms of "lb per MMBtu of heat input" and "lb per hour" using the appropriate F-factors for each fuel. The permittee shall conduct compliance tests for opacity during any federal fiscal year (October 1st to September 30th) that the boiler fires distillate oil for 400 hours or more. [Permit No. 0990005-018-AC; Rule 62-4.070(3), F.A.C.; Rule 62-297.310(7)(a)1, F.A.C.]

RECORD KEEPING AND REPORTING

11. Fuel Sulfur Records: Compliance with the distillate oil fuel sulfur limit shall be demonstrated by taking an initial sample, analyzing the sample for fuel sulfur and reporting the results with the initial emissions compliance test report using fuel oil. Sampling and analyzing the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions or equivalent methods may be used. For each subsequent distillate oil delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content. The permittee shall abide by the Fuel Management Plan specified in Appendices FM. [Permit No. 0990005-018-AC; Rules 62-4.070(3), 62-4.160(15), and 62-297.310(7)(b), F.A.C.; §60.42b (j), §60.45b (j), §60.47b (f), and §60.49b (r)]

12. Operational Records: The permittee shall maintain records sufficient to determine compliance with the following: fuel consumptions rates and hours of operation for each authorized fuel; higher heating value of each authorized fuel; maximum annual heat input rate for the calendar year; and steam production records. Information shall be available for inspection within at least three days of a request from the Department or a Compliance Authority. [Permit No. 0990005-018-AC; Rules 62-4.160(15) and 62-4.070(3), F.A.C.]

13. Test Reports: For each 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. [Permit No. 0990005-018-AC; Rules 62-297.310(8), F.A.C.]

OTHER APPLICABLE REQUIREMENTS

14. 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.]

15. NSPS Provisions: In accordance with Rule 62-204.800(8), F.A.C., Boiler 16 is subject to the applicable requirements of 40 CFR 60, including: Subpart A (General Provisions) and Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units). The applicable provisions are specified in Appendix 60A and Appendix Db in Section 4 of this permit. *{Permitting Note: There are few applicable requirements because this unit fires distillate oil (≤ 0.05% sulfur by weight) and is restricted to an annual capacity factor of 10% by permit.}*

This subsection addresses the following emissions units.

EU No.	Emissions Unit Description
021	Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1
022	Central Dust Collection System No. 2 with Rotoclone No. 2
023	Cooler No. 1 with Rotoclone No. 3
024	Cooler No. 2 with Rotoclone No. 4
025	Fluidized Bed Dryer/Cooler with Baghouse
034	Bulk Load-Out Operation
035	Transfer Bulk Load-out Station
043	Sugar Refinery Alcohol Usage

{Permitting Note: The sugar refinery was last modified by Permit No. 0990005-021-AC.}

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 LÜB-beck (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, which exhausts 89 feet above grade. Wet Rotoclone No. 1 also controls dust from two specialty sugar conveyors that transfer sugar products during production with the rotary dryer and coolers. 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.

Central Dust Collection System No. 2 (EU-022) is used to control dust emissions from several miscellaneous sources including: bucket elevator #10, #16 and #43; the silo scale; belt conveyors #11, #16, #18, #19 A and B; screw conveyors #20, #26, #28, #40, #45, #Q1, #Q2, #S1 and #S2; the packing room bins; the bulk curing bins #1 through #8; and the Sweco shaker screen. The system is controlled by Rotoclone No. 2, which exhausts 86 feet above grade. Rotoclone No. 2 operates when either the Fluidized Bed Dryer or the Rotary Dryer are operating.

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:

Parameter	Specification
Design exhaust flow rate	70,620 acfm
Filtering area	9041 ft^2
Air-to-cloth ratio	7.81 cfm/ft^2
Control efficiency	99.8% (PM and PM_{10})

[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:

EU No.	Description	Control Type	Design Flow Rates acfm	Water Injection Rate (gpm, min.)	Control Efficiency	
					PM	PM_{10}
021	Rotary Dryer, Central Dust Collection System No. 1	Rotoclone No. 1	15,000	2	99.9%	99%

EU No.	Description	Control Type	Design Flow Rates acfm	Water Injection Rate (gpm, min.)	Control Efficiency	
					PM	PM_{10}
022	Central Dust Collection System No. 2	Rotoclone No. 2	15,000	2	99.9%	99%
023	Cooler No. 1	Rotoclone No. 3	15,000	2	99.9%	99%
024	Cooler No. 2	Rotoclone No. 4	15,000	2	99.9%	99%

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

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.

   [Rules 62-4.210 and 62-4.070(3), F.A.C.; and Permit No. 0990005-021-AC]
4. Hours of Operation: Operation of the sugar refinery is limited by the limitations on processing capacities. The hours of operation of are not limited (8760 hours per year). [Permit No. 0990005-021-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]

EMISSION LIMITING STANDARDS

6. Opacity Standards:

   a. Visible emissions shall not exceed 5% opacity from the following exhaust points: Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1 (EU-021); Central Dust Collection System No. 2 with Rotoclone No. 2 (EU-022); Cooler No. 1 with Rotoclone No. 3 (EU-023); Cooler No. 2 with Rotoclone No.4 (EU-024); and Fluidized Bed Dryer/Cooler with Baghouse (EU-025).

   b. Visible emissions shall not exceed 20% 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 21.70 tons of PM per year and 2.70 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 with Rotoclone No. 2 (EU-022); the Cooler No. 1 with Rotoclone No. 3 (EU-023); the Cooler No. 2 with Rotoclone No.4 (EU-024); the Fluidized Bed Dryer/Cooler with Baghouse (EU-025); 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]

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

EU No.	Description	Tons/Year	
		PM	PM_{10}
021	Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1	4.104	1.645
022	Central Dust Collection System No. 2 with Rotoclone No. 2	0.563	0.225
023	Cooler No. 1 with Rotoclone No. 3	4.09	1.64
024	Cooler No. 2 with Rotoclone No.4	0.45	0.18
025	Fluidized Bed Dryer/Cooler with Baghouse	14.70	0.588
034	Bulk Load-Out Operation	3.63	0.15
035	Transfer Bulk Load-out Station	1.83	0.07

[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).

EU No.	Description	PM		PM_{10}	
		Uncontrolled	Control Efficiency	Uncontrolled	Control Efficiency
021	Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1	3.150% (from dryer)plus 0.209 lb/ton (from transfer points)	99.9%	0.126% (from dryer)plus 0.00836 lb/ton (from transfer points)	99.0%
022	Central Dust Collection System No. 2 with Rotoclone No. 2	2.2994 lb/ton	99.9%	0.09198 lb/ton	99.0%

EU No.	Description	PM		PM_{10}	
		Uncontrolled	Control Efficiency	Uncontrolled	Control Efficiency
023	Cooler No. 1 with Rotoclone No. 3	0.175%	99.9%	0.007%	99.0%
024	Cooler No. 2 with Rotoclone No.4	0.175%	99.9%	0.007%	99.0%
025	Fluidized Bed Dryer/Cooler with Baghouse	1.5%	99.8%	0.060%	99.8%
034	Bulk Load-Out Operation	0.105 lb/ton	50%	0.00418 lb/ton	50%
035	Transfer Bulk Load-out Station	0.105 lb/ton	90%	0.00418 lb/ton	90%

[Permit No. 0990005-021-AC]

10. Alcohol Usage: VOC emissions from alcohol usage shall not exceed 39.00 tons during any consecutive 52 weeks 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 Rotoclone 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 Rotoclone No. 1 (EU-021); Central Dust Collection System No. 2 with Rotoclone No. 2 (EU-022); Cooler No. 1 with Rotoclone No. 3 (EU-023); Cooler No. 2 with Rotoclone No.4 (EU-024); and Fluidized Bed Dryer/Cooler with Baghouse (EU-025). [Rule 62-297.310(7)(a)4, F.A.C. and Permit No.0990005-021-AC]

12. Tests Prior to Renewal: Within the 12-month period prior to renewing the operation permit, the following baghouse and Rotoclone 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 Rotoclone No. 1 (EU-021); Central Dust Collection System No. 2 with Rotoclone No. 2 (EU-022); Cooler No. 1 with Rotoclone No. 3 (EU-023); Cooler No. 2 with Rotoclone No.4 (EU-024); and Fluidized Bed Dryer/Cooler with Baghouse (EU-025). [Rule 62-297.310(7)(a)3, F.A.C.]

13. Test Method: Tests to determine visible emissions 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. [Rules 62-204.800 and 62-297.310(4), F.A.C.; 40 CFR 60, Appendix A; and Permit No. 0990005-021-AC]

14. PM Testing: The PM compliance test requirements are waived in lieu of the alternative opacity standard of 5% for: Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1 (EU-021); Central Dust Collection System No. 2 with Rotoclone No. 2 (EU-022); Cooler No. 1 with Rotoclone No. 3 (EU-023); Cooler No. 2 with Rotoclone No.4 (EU-024); and Fluidized Bed Dryer/Cooler with Baghouse (EU-025). 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 weeks period total for all permitted refined sugar production limits. [Rule 62-4.070(3), F.A.C. and Permit No. 0990005-021-AC]

This section of the permit addresses the following emissions units.

ID	Emission Unit Description	ID	Emission Unit Description
018	Central vacuum system No. 1	032	Railcar sugar unloading receiver No. 2
019	Sugar packaging Lines 0-9, including 8A and 8B	045	Powdered sugar dryer/cooler, packaging Line 8A and 8B
020	Sugar grinder	046	Powdered sugar hopper
030	Sugar silos Nos. 1, 2, and 3 (Points #1101-1103)	047	Sugar packaging Lines 12 and 13
031	Railcar sugar unloading receiver No. 1	049	Sugar packaging Line 14

{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 4600 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 and 13 (EU-047) and Line 14 (EU-049)). 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 and packaging Line 14 vents to a dedicated baghouse (EU-049). Sugar is metered from surge bins above the packaging lines for processing into a variety of packages and containers for wholesale and retail distribution.

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 house keeping 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.

ID	Emission Unit Description	Baghouse Specification [a] grains/scf	Exhaust Rate scfm	Stack/Vent Height Feet	Maximum Emissions [b]	
					lb/hour	tons/year
018	Central vacuum system No. 1	0.01	280	8	0.024	0.11
019	Sugar packaging Lines 0-9, including 8A and 8B	0.01	9869	27	0.85	3.71
020	Sugar grinder	0.0005	2961	39	0.013	0.06
030	Sugar silo No. 1 (Point #S1101)	0.02	500	65	0.086	0.38
	Sugar silo No. 2 (Point #S1102)	0.02	500	65	0.086	0.38
	Sugar silo No. 3 (Point #S1103)	0.02	500	65	0.086	0.38
031	Railcar unloading receiver No. 1	0.02	615	5	0.11	0.46
032	Railcar unloading receiver No. 2	0.02	615	5	0.11	0.46
045	Powdered sugar dryer/cooler, packaging Lines 8A and 8B	0.01	8640	48	0.74	3.24
046	Powdered sugar hopper	0.01	1728	42	0.15	0.68
047	Sugar packaging Lines 12 and 13	0.01	3629	48	0.49	2.16
049	Sugar packaging Line 14	0.02	2212	9	0.38	1.66
					Total	13.68

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 8760 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 1300 tons per day. [Permit Nos. 0990005-019-AC and 0990005-023-AC; Rule 62-210.200 (PTE), F.A.C.]

3. Restricted Operation: The hours of operation of are not limited (8760 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% 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 1st to September 30th), each baghouse exhaust point shall be tested to demonstrate compliance with the specified opacity standard. [Rule 62-

297.310(7)(a)4, F.A.C.]

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.]

F. Distillate Oil Storage Tanks

This subsection addresses the following emissions units.

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

EU No.	Emissions Unit Description	Process Area
005	Distillate Oil Storage Tank (50,000 gallons)	Cogeneration Plant

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

EU No.	Emissions Unit Description	Process Area
015	Distillate Oil Storage Tank (29,500 gallons)	Sugar Mill and Refinery
016	Distillate Oil Storage Tank, (29,500 gallons)	Sugar Mill and Refinery
017	Distillate Oil Storage Tank (29,500 gallons)	Sugar Mill and Refinery
040	Fuel Farm	Sugar Mill

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. *ARMS ID No. 0990005*: The three distillate oil storage tanks (EU-015, EU-016 and EU-017) each have a capacity of 29,500 gallons. [Permit No. 0990005-016-AC]
   c. 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.]

G. Paint Spray Booth – Farm Operations

This permit addresses the following emissions unit:

EU No.	Emissions Unit Description	Process Area
048	Paint Booth	Okeelanta Shop

{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_{10}).}

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). [Permit Nos. 0990005-015-AC and 0990005-016-AC]

EMISSIONS LIMITING AND PERFORMANCE RESTRICTIONS

2. Hours of Operation: The hours of operation for this emissions unit are not restricted (8760 hours per year). [Permit No. 0990005-015-AC; Rules 62-4.160(2) and 62-210.200 (PTE), F.A.C.]
3. Permitted Capacity: The maximum throughput rate of paint and thinner shall not exceed 4950 gallons in any consecutive 12 months. [Permit No. 0990005-015-AC; Rules 62-4.160(2) and 62-210.200 (PTE), F.A.C.]
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. [Specific Conditions 7 and 9 in Permit No. 0990005-015-AC; Rule62-210.200 (PTE), F.A.C.]
5. Visible Emissions: Visible emissions from the paint spray booth shall not exceed 20% opacity. [Specific Condition 12 in Permit No. 0990005-015-AC; Rule 62-296.320 (General VE), F.A.C.]
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 materialscontaining volatile organic compounds (VOC). [Permit No. 0990005-015-AC; Rule 62-210.200 (PTE), F.A.C.]

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. [Permit No. 0990005-015-AC; Rule 62-297.310(7)(b), F.A.C.]

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.]

Contents

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 140° F and is sized to accommodate and store up to 2 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 in 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 7-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 of 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

"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

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
ft^2: square feet
ft^3: 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
NO_X: nitrogen oxides
NSPS: New Source Performance Standards
O&M: operation and maintenance
O_2: oxygen
ORIS: Office of Regulatory Information Systems
OS: organic solvent
Pb: lead
PM: particulate matter
PM_{10}: 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
SO_2: 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

Compliance Assurance Monitoring Plan

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).

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]

Compliance Assurance Monitoring Plan

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)

Parametric Criteria	Indicator
Indicator	Opacity
Measurement Approach	Data from the continuous opacity monitoring system (COMS) shall be used to determine potential emissions excursions.
Indicator Range	**An excursion is any 1-hour average of 15% opacity or more.** An excursion requires documentation, investigation, and corrective action.
Data Representativeness	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.
QA/QC Practices	The COMS shall be maintained and calibrated in accordance with the applicable requirements of the permit and 40 CFR 60.
Monitoring Frequency	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.
Data Collection Procedures	The COMS shall continuously report opacity and determine a 1-hour block average.
Averaging Period	1-hour block average

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.

Mill Boiler No. 16 (EU-014)

Permit No. 0990005-018-AC

1. *Deviation*: As required by Condition III.A.9 of the permit, the initial compliance tests for NO_X and opacity were not conducted by April 12, 2007.

   Underlying Cause: Boiler 16 has not operated since the permit was issued on April 12, 2006. The last day of operation was March 16, 2004. The permittee has no immediate plans to operate Boiler 16.

   Plan: The permittee shall conduct each required compliance test within 60 days of initially operating the boiler on a particular fuel type.

2. *Deviation*: As required by Condition III.A.10 of the permit, the initial sampling and analysis of distillate oil in the associated tanks for fuel sulfur was not conducted concurrently with the initial emissions compliance tests.

   Underlying Cause: Boiler 16 has not operated since March 16, 2004. No oil has been delivered or fired since this time.

   Plan: The permittee shall conduct the required sampling/analysis and provide the results within 30 days after commencing operation of Boiler 16 on distillate oil.

3. *Deviation*: As previously reported in the Annual Statements of Compliance, 40 CFR 60.49b(q) requires quarterly reporting of the annual capacity factor and the hours of operation during each quarter. However, when the permit was issued, Boiler 16 had already been shut down for a year. Therefore, Boiler 16 was already subject to the 60-day advance notification of startup required by Rule 62-210.300(5), F.A.C. for shutdown units.

   Underlying Cause: Boiler 16 did not operate and the annual capacity factor and hours of operation were zero.

   Plan: The permittee shall provide written notification of intent to startup Boiler 16 at least 60 days before the intended startup and in accordance with the requirements of Rule 62-210.300(5), F.A.C. Pursuant to 40 CFR 60.49b(q), the permittee shall begin quarterly reporting of the annual capacity factor and hours of operation for the first quarter in which Boiler 16 begins operation.

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)

Rule 62-297.310(2), F.A.C.

Deviation: If a compliance test is conducted below permitted capacity (90% to 100% of maximum operation rate allowed by the permit), this rules limits subsequent operation to 110% of the tested 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.

Underlying Cause: On September 30, 2009, a compliance test was conducted to determine opacity with the unit operating at 608 tons/day, which is below permitted capacity (1300 tons/day). Subsequently, the unit was operated above 110% of the tested rate. On February 15, 2010, the permittee conducted another compliance test at 822 tons/day, which is still below permitted capacity and limits subsequent operation to 904.5 tons/day.

Plan: As necessary, the permittee shall conduct additional opacity tests to remain in compliance with the current tested rate demonstrating compliance with the standard.

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 297.310-1 CALIBRATION SCHEDULE			
ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass	5° F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5° F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/- 0.001" mean of at least three readings; Max. deviation between readings, 0.004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, when 5% change observed, annually	Spirometer or calibrated wet test or dry gas test meter	2%
	2. One Point: Semiannually		
	3. Check after each test series	Comparison check	5%

[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. <u>Required Stack Sampling Facilities</u>: 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. <u>Frequency of Compliance Tests</u>: 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.

b. *Special Compliance Tests.* When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

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 reclaimer 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, 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.]

Good Combustion Plan, Cogeneration Boilers

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 O_2, NO_X, 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 NO_X CEMS data, the permittee shall determine the influence of the flue gas oxygen content on CO and NO_X emissions throughout the range of typical operating loads. As necessary, the permittee shall adjust the flue has oxygen content in the boilers to control CO and NO_X within the permitted emissions standards.

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

EU ID No.	Description	Permit Nos.	Issue Date	Exp. Date.
014	Mill Boiler No. 16			
	Initial Construction	AC50-191876/PSD-FL-169	07/29/1991	030/1/1993
	Extension	AC50-245400/PSD-FL-169	03/15/1994	10/30/1994
	Amendment	AC50-191876/PSD-FL-169	---	10/30/1994
	Amendment	AC50-191876/PSD-FL-169	---	10/30/1994
	Modification, conversion to distillate oil and gas	0990005-009-AC/PSD-FL-169A	10/30/2001	11/01/2003
	Modification, restricted to 10% annual capacity factor	0990005-018-AC/PSD-FL-169A	04/12/2006	04/01/2007
015	Fuel Storage Tank			
		AC50-265485	5/23/1995	05/22/1996
016	Fuel Storage Tank			
	Initial (After-the-Fact)	AC50-265485	5/23/1995	05/22/1996
017	Fuel Storage Tank			
	Initial (After-the-Fact)	AC50-265485	5/23/1995	05/22/1996
018	Central Vacuum System			
	Initial (After-the-Fact)	0990005-001-AC	01/26/1996	01/26/2001
	Modification	0990005-004-AC	07/11/2000	07/11/2005
	Modification, expansion	0990005-008-AC	05/10/2001	05/10/2006
	Concurrent Modification w/Permit No. 0990005-012-AV	0990005-013-AC	11/13/2003	08/22/2006
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
019	Packaging Lines, including 8A and 8B			
	Initial (After-the-Fact) Construction	0990005-001-AC	01/26/1996	01/26/2001
	Modification	0990005-004-AC	07/11/2000	07/11/2005
	Modification	0990005-008-AC	05/10/2001	05/10/2006
	Concurrent Modification w/Permit No. 0990005-012-AV	0990005-013-AC	11/13/2003	08/22/2006
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
	Modification	0990005-023-AC	01/16/2009	01/15/2010

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

EU ID No.	Description	Permit Nos.	Issue Date	Exp. Date.
020	Sugar Grinder and Hopper			
	Initial (After-the-Fact) Construction	0990005-001-AC	01/26/1996	01/26/2001
	Modification	0990005-004-AC	07/11/2000	07/11/2005
	Modification	0990005-008-AC	05/10/2001	05/10/2006
	Concurrent Modification w/Permit No. 0990005-012-AV	0990005-013-AC	11/13/2003	08/22/2006
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
021	Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1			
	Initial (After-the-Fact) Construction	0990005-002-AC	7/18/1996	07/18/2001
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
022	Central Dust Collection System No. 2 with Rotoclone No. 2			
	Initial (After-the-Fact)	0990005-002-AC	7/18/1996	07/18/2001
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
023	Cooler No. 1 with Rotoclone No. 3			
	Initial (After-the-Fact)	0990005-002-AC	7/18/1996	07/18/2001
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
024	Cooler No. 2 with Rotoclone No.4			
	Initial (After-the-Fact)	0990005-002-AC	7/18/1996	07/18/2001
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
025	Fluidized Bed Dryer/Cooler with Baghouse			
	Initial	0990005-002-AC	7/18/1996	07/18/2001
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
026	Sugar Silo (S1101)			

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

EU ID No.	Description	Permit Nos.	Issue Date	Exp. Date.
	Initial (After-the-Fact)	0990005-001-AC	01/26/1996	01/26/2001
	Construction	0990005-008-AC	05/10/2001	05/10/2006
	Concurrent Modification w/Permit No. 0990005-012-AV	0990005-013-AC	11/13/2003	08/22/2006
027	Sugar Silo (S1102)			
	Initial (After-the-Fact)	0990005-001-AC	01/26/1996	01/26/2001
	Construction	0990005-008-AC	05/10/2001	05/10/2006
	Concurrent Modification w/Permit No. 0990005-012-AV	0990005-013-AC	11/13/2003	08/22/2006
028	Sugar Silo (S1103)			
	Initial (After-the-Fact)	0990005-001-AC	01/26/1996	01/26/2001
	Construction	0990005-008-AC	05/10/2001	05/10/2006
	Concurrent Modification w/Permit No. 0990005-012-AV	0990005-013-AC	11/13/2003	08/22/2006
030	Sugar silos Nos. 1, 2, and 3 (Points #1101-1103)			
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
031	Railcar Sugar Unloading Receiver No. 1			
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
032	Railcar Sugar Unloading Receiver No. 2			
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
034	Bulk Load-Out Operation			
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
035	Transfer Bulk Load-Out Station			
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
043	Sugar Refinery Alcohol Usage			
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008

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

EU ID No.	Description	Permit Nos.	Issue Date	Exp. Date.
045	Powdered Sugar Dryer/Cooler, packaging Lines 8A and 8B			
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
	Modification	0990005-023-AC	01/16/2009	01/15/2010
046	Powdered Sugar Hopper			
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
047	Sugar Packaging Lines (11-14)			
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
	Modification	0990005-023-AC	01/16/2009	01/15/2010
048	Paint Booth			
	Initial Construction	0990005-010-AC	08/22/2001	08/22/2006
	Modification	0990005-015-AC	11/02/2005	11/02/2010
049	Sugar packaging Line 14			
	Initial Construction	0990005-023-AC	01/162009	01/15/2010

ARMS ID. No. 0990332 – New Hope Power's Okeelanta Cogeneration Plant

EU ID No.	Description
001	Cogeneration Boiler No. A
002	Cogeneration Boiler No. B
003	Cogeneration Boiler No. C
004	Cogeneration Plant - Material Handling and Storage
005	Cogeneration Plant – Miscellaneous Support Equipment

Description	Permit Nos.	Issue Date	Exp. Date.
Initial air construction permit (AC50-219413)	AC50-219413 (PSD-FL-196)	09/27/1993	07/01/1996
Extension of initial air construction permit	AC50-219413 (PSD-FL-196)	---	Unknown
Modified to add limit of 30% yard trash (NSPS Subpart Ea)	0990332-001-AC (PSD-FL-196A)	02/20/1996	04/01/1997
1st Extension for simultaneous operation with mill boilers	0990332-002-AC (PSD-FL-196B)	06/14/1996	04/01/1997
Temporary permit to conduct trial burn of TDF (expired)	0990332-003-AC (PSD-FL-196C)	01/22/1997	12/31/1998
Modified SAM test method	0990332-004-AC (PSD-FL-196D)	04/18/1997	12/31/1998
2nd Extension for simultaneous operation with mill boilers	0990332-005-AC (PSD-FL-196E)	04/05/1997	04/01/1998
Modified of CO, Pb, and Hg standards	0990332-006-AC (PSD-FL-196F)	10/24/1997	07/01/1998
Modified performance test schedule (Specific Condition #11)	0990332-007-AC (PSD-FL-196G)	05/08/1997	04/01/1998
Withdrawn	0990332-008-AC (PSD-FL-196H)	09/15/1997	Withdrawn
3rd Extension for simultaneous operation with mill boilers	0990332-009-AC (PSD-FL-196I)	06/15/1998	04/01/2001
Modified CO standard	0990332-010-AC (PSD-FL-196J)	06/24/1999	04/01/2001
4th Extension for simultaneous operation with mill boilers	0990332-011-AC (PSD-FL-196K)	11/16/2000	10/01/2002
Modified to add mechanical dust collectors before ESP	0990332-012-AC (PSD-FL-196K)	12/22/1999	10/01/2002
Modified to add natural gas as startup/supplemental fuel	0990332-013-AC (PSD-FL-196L)	01/24/2001	10/01/2002
Modified CO, Fl, Pb, Hg, SO_2, and SAM standards	0990332-014-AC (PSD-FL-196M)	01/31/2002	10/01/2002
Modified electrical generation basis from "gross" to "net"	0990332-015-AC (PSD-FL-196N)	05/01/2001	10/01/2002
Modified maximum heat input rate to 760 MMBtu per hour	0990332-016-AC (PSD-FL-196O)	10/27/2003	09/01/2004
Modified to add 65 MW steam turbine electrical generator	0990332-017-AC (PSD-FL-196P)	06/06/2005	12/15/2006

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_2, NO_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_X; 260 tons/year of PM; 260 tons/year of PM_{10}; 37 tons/year of SAM; 599 tons/year of SO_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 H_2O
- 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:

1. Transformer/Rectifier (T/R) Set
   a. Transformer Liquid
   b. Ground Connections
   c. High Tension Bus Duct
   d. Conduits
   e. Alarm Connections
   f. Ground Switch Operation
   g. High Voltage Connections
   h. Surge Arrestors

2. T/R Control Panel
   a. Wire Terminations
   b. Ground Connections
   c. Circuit Breakers Trip
   d. Mechanism
   e. Meter Terminations
   f. Air Filters, For Cleanliness
   g. Fans

3. Control Panels
   a. Indicator Lights
   b. Locked Cabinets
   c. Meters Recorded

4. Insulator Compartment System
   a. Bushing
   b. Sealings

5. Casing, Nozzles, & Inlet Duct
   a. Buildup
   b. Corrosion

6. Stacks
   a. Buildup
   b. Corrosion

7. Gas Distribution Plates
   a. Buildup
   b. Corrosion

8. Inspection Doors
   a. Gasket
   b. Locking Arrangement
   c. Corrosion

9. Through Hopper
   a. Build-up
   b. Corrosion
   c. Leaks
   d. Access Doors

10. Rappers
   a. Seals
   b. Bearings
   c. Clearance to Supports
   d. Shaft Alignment
   e. Free Rotation of Hammers
   f. Shaft Insulators
   g. Hammer/Anvil Alignment
   h. Inner Arm Wear
   i. Hammer Attached

11. Rapper Motors
   a. Motor/Lubrication
   b. Sequencing
   c. Noise
   a.

12. Discharge Electrodes
   b. Support Tubes and Insulators
   c. Electrodes
   d. Alignment
   e. Corrosion
   f. Build-up

13. Collecting Electrodes
   a. Supports
   b. Alignment
   c. Corrosion
   d. Buildup

14. Gas Sneakage Baffles
   a. Buildup
   b. Properly Located

15. Screw Conveyors
   a. Lubrication
   b. Gear Box Lubrication
   c. Condition of Screw
   d. Pluggage (Inlet & Outlet)
   e. Belt Tension

16. Rotary Air Locks
   a. Lubrication
   b. Gear Box Lubrication
   c. Condition of Rotor
   d. Pluggage (Inlet and Outlet)
   e. Belt Tension

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_X control. The technology is a selective non-catalytic reduction (SNCR) process, which reduces NO_X emissions through chemical reactions with urea. In this process, urea is injected into the flue gas stream and reacts with NO_X to form nitrogen and water vapor. The NOx 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_X emission rate of 0.15 lb/MMBtu when firing biomass or No. 2 fuel oil. At maximum capacity, the Urea injection rate is approxiamtely 65 gph and the ammonia slip may be as high as 25 ppmvd. The NOx 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_X pump in service, NO_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 NO_X control plan identifies the minimum urea injection rate that has demonstrated continuous compliance with the NO_X emissions limit at various load conditions. The purpose of this plan is to monitor compliance with the NO_X standards when the CEM for NO_X is not operating. If a CEM for NO_X 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 NO_X monitors at New Hope Power Company have had downtimes of less than 1 percent. As a result, the alternative NO_X 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/filer. 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.

Quarterly Report, Cogeneration Boilers

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

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

Emissions Unit Description Spreader stoker boiler with maximum heat input of 760 MMBtu/hour ARMS EU ID No. ______ Cogeneration Boiler: ___ A ___ B ___ C	**Unit Operation in Calendar Quarter** ________ hours

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

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

Pollutant Monitored ***(Check one.)*** _____ CO _____ NOx _____ SO2 _____ Opacity	**Calendar Quarter of Operation Covered** ***(Check one.)*** ___ 1 ___ 2 ___ 3 ___ 4 for year ________
Continuous Monitor Information Manufacturer: ____________________ Model No. ____________________ Date of last certification or audit: ____________	**Emission Standards** _______ lb/MMBtu of heat input, 24-hour rolling avg. _______ lb/MMBtu of heat input, 30-day rolling avg. _______ lb/MMBtu of heat input, 12-month rolling avg. _______ % opacity, except for one 6-minute block per hour ≤ ______ % opacity
Emission Data Summary 1. Duration of excess emissions in reporting period due to: a. Startup/shutdown .... ______ b. Control equipment problems .... ______ c. Process problems .... ______ d. Other known causes .... ______ e. Unknown causes .... ______ 2. Total duration of excess emissions .... ______ 3. [Total duration of excess emissions] x (100%) .... ______ [Total source operating time]	**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]
Note: Report "excess emissions" as emission averages that are in excess of a permitted emissions standard. For gases, report excess emissions in terms of hours. For opacity, report excess emissions in terms of minutes.	*If monitor availability is not at least 95%, provide a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability*

Emissions Data Exclusion

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

PERMIT SUBSECTION 3A - COGENERATION BOILERS

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

EU No.	Emissions Unit Description
001	Cogeneration Boiler A
002	Cogeneration Boiler B
003	Cogeneration Boiler C
004	Cogeneration Plant – Material Handling and Storage

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)

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 (CO_2) in lieu of oxygen, and sulfur dioxide (SO_2).

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:

Pollutant	Averaging Period	Compliance Method
CO	0.50 lb/MMBtu, 30-day rolling avg.	CEMS
	0.35 lb/MMBtu, 12-month rolling avg.	
NO_X	0.15 lb/MMBtu, 30-day rolling avg.	CEMS
SO_2	0.20 lb/MMBtu, 24-hour rolling avg.	CEMS
	0.10 lb/MMBtu, 30-day rolling avg.	
	0.06 lb/MMBtu, 12-month rolling avg.	
Opacity	≤ 20%, except for one 6-minute block per hour that is ≤ 27%	COMS and EPA Method 9
PM/PM_{10}	0.026 lb/MMBtu, 3-run test avg.	EPA Method 5 Stack Test
VOC	0.05 lb/MMBtu, 3-run test avg.	EPA Method 25A Stack Test
Mercury	5.4×10^{-06} lb/MMBtu, 3-run test avg.	EPA Method 101A or 29 or 30B

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.

Federal Regulations: NSPS Subpart A (General Provisions); Subpart Da (Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978); 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)

CAM: PM/PM_{10} emissions controlled by multi-cyclones and ESP

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

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

EU No.	Emissions Unit Description
004	Material Handling and Storage Operations includes unloading operations, stockpiles, transfer operations, conveyors, screens, crushers, hoppers and silos. Hours of operation are not restricted.

Fly Ash Silo and Activated Carbon Silo:

Controls: Baghouses ≤ 0.01 grains per acfm (design specification for new and replacement bags).

Opacity Standard: Visible emissions ≤ 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 - BOILER 16, SUGAR MILL & REFINERY

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

EU No.	Emissions Unit Description
EU-014	Boiler 16

Maximum Heat Input Rate: 211 MMBtu/hour (gas) and 202 MMBtu/hours (oil)

Maximum Steam Rate: 150,000 lb/hour, 24-hour average

Authorized Fuels: Natural gas and distillate oil (≤ 0.05% sulfur by weight)

Restrictions: Operating hours are not restricted. Maximum heat input rate is restricted to 184,836 MMBtu per calendar year. This is less than 10% of the maximum potential annual heat input rate, which avoids PSD preconstruction review and most of the NSPS Subpart Db monitoring provisions.

Monitoring: Continuous monitoring of steam rate, steam temperature, steam pressure, and fuel flow rates.

NOx Controls: Low-NOx burners and flue gas recirculation (~15%)

Opacity Standard: ≤ 20% except for one 6-minute period per hour ≤ 27%

NOx Standard (Gas): 0.20 lb/MMBtu (42.2 lb/hour)

NOx Standard (Oil): 0.20 lb/MMBtu (40.4 lb/hour)

Compliance Tests: Conduct EPA Method 7E for NOx prior to permit renewal. Conduct EPA Method 9 for opacity each year that the boiler fires 400 hours or more of distillate oil.

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

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

Fuel Records: Maintain certified fuel analyses from vendors for each delivery.

Operational Records: Maintain records of: fuel consumptions rates and hours of operation for each authorized fuel; higher heating value of each authorized fuel; maximum annual heat input rate for the calendar year; and steam production records.

Federal Regulations: NSPS Subpart Db; NESHAP Subpart DDDDD

CAM: No

PERMIT SUBSECTION 3D - SUGAR REFINERY

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

EU No.	Emissions Unit Description
021	Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1
022	Central Dust Collection System No. 2 with Rotoclone No. 2
023	Cooler No. 1 with Rotoclone No. 3
024	Cooler No. 2 with Rotoclone No. 3
025	Fluidized Bed Dryer/Cooler with Baghouse
034	Bulk Load-Out Operation
035	Transfer Bulk Load-out Station
043	Sugar Refinery Alcohol Usage

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.

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

ID	Emission Unit Description	ID	Emission Unit Description
018	Central vacuum system No. 1	032	Railcar sugar unloading receiver No. 2
019	Sugar packaging Lines 0-9, including 8A and 8B	045	Powdered sugar dryer/cooler, packaging Line 8A and 8B
020	Sugar grinder	046	Powdered sugar hopper
030	Sugar silos Nos. 1, 2, and 3 (Points #1101-1103)	047	Sugar packaging lines (11-14)
031	Railcar sugar unloading receiver No. 1	049	Sugar packaging Line 14

Permitted Capacity: The maximum sugar packaging rate is 1300 tons/day. Hours of operation of 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.

Compliance Tests: Conduct EPA Method 9 for opacity annually.

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

EU No.	Emissions Unit Description
005	Cogeneration Plant – Miscellaneous Support Equipment

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

EU No.	Emissions Unit Description
015	Distillate Oil Storage Tank (29,500 gallons)
016	Distillate Oil Storage Tank (29,500 gallons)
017	Distillate Oil Storage Tank (29,500 gallons)

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

EU No.	Emissions Unit Description
048	Paint Booth

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

TV17. Permit Revision Procedures. The permittee shall revise its permit as required by Rules 62-213.400, 62-213.412, 62-213.420, 62-213.430 & 62-4.080, F.A.C.; and, in addition, the Department shall revise permits as provided in Rule 62-4.080, F.A.C. & 40 CFR 70.7(f).

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 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)(d)1., 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)2., 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.

b. *Continuous Emissions Monitoring System (CEMS).*

(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.

c. *Mass Balance Calculations.*

(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

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)

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

Unregulated and Insignificant Emissions Units and/or Activities

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

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

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

- Hi-Vac industrial vacuum system
- 300 hp gas-fired package boiler
- Sugar bin with dust collector (refined sugar warehouse #3)

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

ID No.	EU Description	Activities/Equipment
005	Cogeneration Plant - Miscellaneous support equipment	• 50,000 gallon distillate oil tank • Nominal 75 MW Steam Turbine Electrical Generator • Nominal 65 MW Steam Turbine Electrical Generator • Condensers • Two Cooling Towers • Switchyard, etc. • Boiler Drum Blowdown Tank • Diesel Fire Pump Engine • Propane Tank • Hydrogen Sulfide Degasifier • Oil/water Separators • Sodium Hydroxide Tank • Wastewater Neutralization Tank • Cold Cleaning Devices (Parts Washers) • Sulfuric Acid Storage and Distribution Systems • Painting Operations

ID No.	EU Description	Activities/Equipment
		• Portable Diesel Air Compressors • Portable Electric Generators • Portable Welders • Pressurized LPG Tanks • Portable Pumps • Forklift, loader and crane operations

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) and Boiler 16 (EU 014)

In accordance with Rule 62-204.800(8), F.A.C., the cogeneration boilers and Boiler 16 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 controlagency 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 60.1(a), (b) and (c)]

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 re-port (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)]

(c) 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)].

(d) 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 perfomance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) 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)].

(f) 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) (1) 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 continuos 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).
[Rule 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.

[Rule 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 60.45(g)(3), 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.
[Rule 62-296.800, F.A.C.; 40 CFR 60.14(f)].

(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.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(d)].

(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.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(e)].

(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.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(f)].

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(g)].

§ 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, Vmax, as determined by the following equation:

$$V_{max}=(X_{H2}-K_1)*K_2$$

Where:

V_{max}=Maximum permitted velocity, m/sec.

K_1=Constant, 6.0 volume-percent hydrogen.

K_2=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:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Eq. 1

where:

HT=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;

$$K = \text{Constant, } 1.740 \times 10^{-7} \left(\frac{1}{\text{ppm}}\right) \left(\frac{\text{g mole}}{\text{scm}}\right) \left(\frac{\text{MJ}}{\text{kcal}}\right)$$

where the standard temperature for $\left(\frac{\text{g mole}}{\text{scm}}\right)$ is 20°C;

Eq. 2

Ci=Concentration of sample component i 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

Hi=Net heat of combustion of sample component i, kcal/g mole at 25 °>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, Vmax, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation. Log10 (Vmax)=(HT+28.8)/31.7

Vmax=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, Vmax, for air-assisted flares shall be determined by the following equation.

Vmax=8.706+0.7084 (HT)

Vmax=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)*: SO_2 NO_X TRS H_2S 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: ____________

Emission Data Summary [1]		**CMS Performance Summary** [1]	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/shutdown	____	a. Monitor equipment malfunctions	____
b. Control equipment problems	____	b. Non-Monitor equipment malfunctions	____
c. Process problems	____	c. Quality assurance calibration	____
d. Other known causes	____	d. Other known causes	____
e. Unknown causes	____	e. Unknown causes	____
2. Total duration of excess emissions	____	2. Total CMS Downtime	____
3. [Total duration of excess emissions] x (100%) / [Total source operating time]	____ % [2]	3. [Total CMS Downtime] x (100%) / [Total source operating time]	____ % [2]

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: ____________

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.

§ 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 de-fined 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. <u>NSPS Subpart Da</u>: 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.

§ 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 SO_2 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 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:

(1) If emissions of sulfur dioxide to the atmosphere are greater than 260 ng/J (0.60 lb/million Btu) heat input

$E_s = (340x+520\,y)/100$ and

$\%P_s = 10$

(2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 260 ng/J (0.60 lb/million Btu) heat input:

$E_s = (340x+520\,y)/100$ and

$\%Ps = (10x+30\,y)/100$

where:

Es is the prorated sulfur dioxide emission limit (ng/J heat input),

%Ps 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.}*

§ 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 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) NO_X emission limits.

Fuel type	Emission limit for heat input	
	ng/J	(lb/MMBtu)
Gaseous fuels: All other fuels	86	0.20
Liquid fuels: All other fuels	130	0.30
Solid fuels: All other fuels	260	0.60

(2) NO_X reduction requirement.

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25%
Liquid fuels	30%
Solid fuels	65%

(b) *{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:

$E_n = [86\ w + 130\ x + 210\ y + 260\ z + 340\ v]/100$

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) *{Not applicable.}*

§ 60.45Da Standard for mercury.

(a) and (b) *{Not applicable.}*

§ 60.46Da [Reserved]

§ 60.47Da Commercial demonstration permit.

(a) through (e) *{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) After the initial performance test required under Sec. 60.8, 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 SO_2 and NO_X emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_X only), or emergency conditions (SO_2) only.

(2) Compliance with applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 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, the owner or operator shall 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 paragraph (j) of this section.

(1) Method 6 shall be used to determine the SO_2 concentration at the same location as the 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 NO_X concentration at the same location as the 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 O_2 or CO_2 concentration at the same location as the O_2 or 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 O_2, SO_2, and NO_X concentrations respectively.

(2) SO_2 or NO_X (NO), as applicable, shall be used for preparing the calibration gas mixtures (in 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 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent 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 SO_2 and NO_X. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the particulate matter standards in Sec. 60.42Da as follows:

(1) The dry basis F factor (O_2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

(2) For the particular 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 O_2 concentration. The O_2 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 O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 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 SO_2 standards in Sec. 60.43Da as follows:

(1) through (3) *{Not applicable.}*

(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) as applicable.

(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) *{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) *{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 SO_2 and/or NO_X and/or opacity and/or 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 electronic 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 - BOILER 16 (EU 014)

In accordance with Rule 62-204.800(8), F.A.C., Boiler 16 (EU 014) is subject to the applicable requirements of 40 CFR 60 Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. For these requirements, the original rule numbering has been retained.

{Permitting Note: There are few applicable requirements because this unit fires distillate oil (≤ 0.05% sulfur by weight) and is restricted to an annual capacity factor of 10% by permit.}

§ 60.40b Applicability and Delegation of Authority

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 million Btu/hour.

§ 60.41b Definitions

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §§60.42b(a), 60.43b(a), or 60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396-78, Standard Specifications for Fuel Oils (incorporated by reference -see §60.17).

Very low sulfur oil means oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 215 ng/J (0.5 lb/million Btu) heat input.

§ 60.42b Standard for Sulfur Dioxide

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (2) maintaining fuel receipts as described in §60.49b(r).

§ 60.43b Standard for Particulate Matter

(h) (5) On or after the date on which the initial performance test is completed or is required to be completed under Sec. 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.3 weight percent sulfur or other liquid or gaseous fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less is not subject to the PM or opacity limits in this section. *{Permitting Note: On March 1, 2006, the Department received an email from EPA Region 4 clarifying the February 2006 revisions to NSPS Subpart Db for industrial boilers. If the facility combusts only oil containing no more than 0.3% sulfur by weight, the revisions now exempt affected facilities constructed, reconstructed, or modified after February 18, 2005 from particulate matter and opacity limits. Boiler 16 is permitted to fire only natural gas or distillate oil containing no more than 0.05% sulfur by weight. In accordance with § 60.46b(i), compliance must be demonstrated obtaining fuel supplier certifications of sulfur content.}*

§ 60.44b Standard for Nitrogen Oxides

(k) Affected facilities that meet the criteria described in paragraphs (j) (1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 million Btu/hour) or less, are not subject to the nitrogen oxides emission limits under this section.

(j) The sub-paragraphs in paragraph (j) state:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a Federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil and a nitrogen content of 0.30 weight percent or less.

{Note: The boiler is authorized to fire only natural gas and distillate oil (≤ 0.05% sulfur by weight). The permit restricts the annual capacity to no more than 10%. Therefore, there is no applicable NO_X standard.}

§ 60.45b Compliance and Performance Test Methods and Procedures for Sulfur Dioxide

(j) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

§ 60.46b Compliance and Performance Test Methods and Procedures for Particulate Matter and Nitrogen Oxides

(i) Units burning only oil that contains no more than 0.3 weight percent sulfur or liquid or gaseous fuels with a potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less may demonstrate compliance by maintaining fuel supplier certifications of the sulfur content of the fuels burned.

{Permitting Note: There are no applicable standards for particulate matter or nitrogen oxides.}

§ 60.47b Emission Monitoring for Sulfur Dioxide

(f) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the emission monitoring requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

§ 60.48b Emissions Monitoring for Particulate Matter and Nitrogen Oxides

{Permitting Note: There are no applicable standards for particulate matter or nitrogen oxides.}

§ 60.49b Reporting and Recordkeeping Requirements

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility.

(2) If applicable, a copy of any a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i).

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired.

{Note: The permittee has previously complied with the above initial requirement.}

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date,

(2) The number of hours of operation, and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator on a quarterly basis:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the quarter, if residual oil was fired; and

(3) If the affected facility meets the criteria described in §60.44b(j), the results of any nitrogen oxides emission tests required during the quarter, the hours of operation during the quarter, and the hours of operation since the last nitrogen oxides emission test.

(r) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under Sec. 60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in Sec. 60.41b. For the purposes of this section, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Quarterly reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the preceding quarter.

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) *{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.

§ 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 de-fined 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.

Friday, Barbara

To:	ricardo_lima@floridacrystals.com
Cc:	'matthew_capone@floridacrystals.com'; 'dbuff@golder.com'; Satyal, Ajaya; 'James_Stormer@doh.state.fl.us'; Halpin, Mike; 'Forney.Kathleen@epamail.epa.gov'; abrams.heather@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Koerner, Jeff; Holtom, Jonathan; Walker, Elizabeth (AIR)
Subject:	OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV
Attachments:	0990005-017-AVSignedNoticeofFinalPermit.pdf

Dear Sir/ Madam:

Attached is the official **Notice of Final Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document

Attention: Jeff Koerner

Owner/Company Name: OKEELANTA CORP
Facility Name: OKEELANTA SUGAR REFINERY
Project Number: 0990005-017-AV
Permit Status: FINAL
Permit Activity: PERMIT RENEWAL
Facility County: PALM BEACH

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0990005.017.AV.F_pdf.zip

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/emission/apds/default.asp . "

Permit project documents that are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation.

Barbara Friday
Bureau of Air Regulation
Division of Air Resource Management (DARM)
(850)921-9524

Friday, Barbara

From: Microsoft Exchange
To: ricardo_lima@floridacrystals.com; 'matthew_capone@floridacrystals.com'
Sent: Friday, July 16, 2010 10:58 AM
Subject: Relayed: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:

ricardo_lima@floridacrystals.com

'matthew_capone@floridacrystals.com'

Subject: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Sent by Microsoft Exchange Server 2007

Friday, Barbara

From: Ricardo Lima [Ricardo_Lima@floridacrystals.com]
To: Friday, Barbara
Sent: Tuesday, July 20, 2010 4:24 PM
Subject: Read: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Your message was read on Tuesday, July 20, 2010 4:24:19 PM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Matthew Capone [Matthew_Capone@floridacrystals.com]
Sent: Friday, July 16, 2010 2:26 PM
To: Friday, Barbara
Cc: Ricardo Lima
Subject: RE: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

This reply confirms receipt and viewing of permit documents.

Matthew Capone
Okeelanta Corporation &
New Hope Power Company
(561)993-1658

From: Friday, Barbara [mailto:Barbara.Friday@dep.state.fl.us]
Sent: Friday, July 16, 2010 10:58 AM
To: Ricardo Lima
Cc: Matthew Capone; dbuff@golder.com; Satyal, Ajaya; James_Stormer@doh.state.fl.us; Halpin, Mike; Forney.Kathleen@epamail.epa.gov; abrams.heather@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Koerner, Jeff; Holtom, Jonathan; Walker, Elizabeth (AIR)
Subject: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Dear Sir/ Madam:

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Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document

Attention: Jeff Koerner

Owner/Company Name: OKEELANTA CORP
Facility Name: OKEELANTA SUGAR REFINERY
Project Number: 0990005-017-AV
Permit Status: FINAL
Permit Activity: PERMIT RENEWAL
Facility County: PALM BEACH

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0990005.017.AV.F_pdf.zip

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/emission/apds/default.asp . "

Permit project documents that are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation.

Barbara Friday
Bureau of Air Regulation
Division of Air Resource Management (DARM)
(850)921-9524

The Department of Environmental Protection values your feedback as a customer. DEP Secretary Michael W. Sole is committed to continuously assessing and improving the level and quality of services provided to you. Please take a few minutes to comment on the quality of service you received. Simply click on this link to the DEP Customer Survey. Thank you in advance for completing the survey.

Friday, Barbara

From: Mail Delivery System [MAILER-DAEMON@mx1.golder.com]
To: dbuff@golder.com
Sent: Friday, July 16, 2010 10:58 AM
Subject: Relayed: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:

dbuff@golder.com

Subject: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Friday, Barbara

From: Buff, Dave [DBuff@GOLDER.com]
To: Friday, Barbara
Sent: Friday, July 16, 2010 11:20 AM
Subject: Read: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Your message was read on Friday, July 16, 2010 11:20:29 AM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Microsoft Exchange
To: Satyal, Ajaya; Walker, Elizabeth (AIR); Koerner, Jeff
Sent: Friday, July 16, 2010 10:58 AM
Subject: Delivered: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Your message has been delivered to the following recipients:

Satyal, Ajaya

Walker, Elizabeth (AIR)

Koerner, Jeff

Subject: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Sent by Microsoft Exchange Server 2007

Friday, Barbara

From: Satyal, Ajaya
To: Friday, Barbara
Sent: Friday, July 16, 2010 11:15 AM
Subject: Read: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Your message was read on Friday, July 16, 2010 11:14:47 AM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Satyal, Ajaya
Sent: Friday, July 16, 2010 11:16 AM
To: Friday, Barbara
Subject: RE: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Thanks Barbara, received the document.

AJ Satyal
FDEP-SD

From: Friday, Barbara
Sent: Friday, July 16, 2010 10:58 AM
To: ricardo_lima@floridacrystals.com
Cc: matthew_capone@floridacrystals.com; dbuff@golder.com; Satyal, Ajaya; James_Stormer@doh.state.fl.us; Halpin, Mike; Forney.Kathleen@epamail.epa.gov; abrams.heather@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Koerner, Jeff; Holtom, Jonathan; Walker, Elizabeth (AIR)
Subject: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

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Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document

Attention: Jeff Koerner

Owner/Company Name: OKEELANTA CORP
Facility Name: OKEELANTA SUGAR REFINERY
Project Number: 0990005-017-AV
Permit Status: FINAL
Permit Activity: PERMIT RENEWAL
Facility County: PALM BEACH

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0990005.017.AV.F_pdf.zip

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/emission/apds/default.asp . "

Permit project documents that are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation.

Barbara Friday
Bureau of Air Regulation
Division of Air Resource Management (DARM)
(850)921-9524

The Department of Environmental Protection values your feedback as a customer. DEP Secretary Michael W. Sole is committed to continuously assessing and improving the level and quality of services provided to you. Please take a few minutes to comment on the quality of service you received. Simply click on this link to the DEP Customer Survey. Thank you in advance for completing the survey.

Friday, Barbara

From: Microsoft Exchange
To: 'James_Stormer@doh.state.fl.us'
Sent: Friday, July 16, 2010 10:58 AM
Subject: Relayed: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:

'James_Stormer@doh.state.fl.us'

Subject: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Sent by Microsoft Exchange Server 2007

Friday, Barbara

From: James_Stormer@doh.state.fl.us
To: Friday, Barbara
Sent: Friday, July 16, 2010 12:06 PM
Subject: Read: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Your message was read on Friday, July 16, 2010 12:05:38 PM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Microsoft Exchange
To: Halpin, Mike; Holtom, Jonathan; Gibson, Victoria
Sent: Friday, July 16, 2010 10:58 AM
Subject: Delivered: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Your message has been delivered to the following recipients:

Halpin, Mike

Holtom, Jonathan

Gibson, Victoria

Subject: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Sent by Microsoft Exchange Server 2007

Friday, Barbara

From: Holtom, Jonathan
To: Friday, Barbara
Sent: Friday, July 16, 2010 1:08 PM
Subject: Read: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Your message was read on Friday, July 16, 2010 1:07:52 PM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Halpin, Mike
Sent: Friday, July 16, 2010 11:02 AM
To: Friday, Barbara
Subject: Delivered: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV
Attachments: ATT00001

Your message was delivered to the recipient.

Friday, Barbara

From: Halpin, Mike
To: Friday, Barbara
Sent: Friday, July 16, 2010 11:04 AM
Subject: Read: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Your message was read on Friday, July 16, 2010 11:04:06 AM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Gibson, Victoria
To: Friday, Barbara
Sent: Friday, July 16, 2010 11:32 AM
Subject: Read: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Your message was read on Friday, July 16, 2010 11:32:25 AM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Mail Delivery System [MAILER-DAEMON@mseive02.rtp.epa.gov]
To: Forney.Kathleen@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; abrams.heather@epamail.epa.gov
Sent: Friday, July 16, 2010 10:58 AM
Subject: Relayed: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:

Forney.Kathleen@epamail.epa.gov

Oquendo.Ana@epamail.epa.gov

abrams.heather@epamail.epa.gov

Subject: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Friday, Barbara

From: Koerner, Jeff
To: Friday, Barbara
Sent: Friday, July 16, 2010 11:00 AM
Subject: Read: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV

Your message was read on Friday, July 16, 2010 10:59:59 AM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Walker, Elizabeth (AIR)
Sent: Friday, July 16, 2010 11:02 AM
To: Friday, Barbara
Subject: Delivered: OKEELANTA CORPORATION, SUGAR MILL AND REFINERY; 0990005-017-AV
Attachments: ATT00001

Your message was delivered to the recipient.