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BUREAU OF AIR REGULATION

AIR CONSTRUCTION PERMIT APPLICATION FOR OKEELANTA BOILER NO. 16

OKEELANTA CORPORATION

Prepared For:
Okeelanta Corporation

Prepared By:
Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

December 2005
0537520

APPLICATION

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:
- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:
- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Okeelanta Corporation**	
2. Site Name: **Okeelanta Sugar Mill**	
3. Facility Identification Number: **0990005**	
4. Facility Location...: Street Address or Other Locator: **21250 U.S. Highway 27 South** City: **South Bay** County: **Palm Beach** Zip Code: **33493**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Matthew Capone, Director of Environmental Programs**
2. Application Contact Mailing Address... Organization/Firm: **Okeelanta Corporation** Street Address: **21250 U.S. Highway 27** City: **South Bay** State: **FL** Zip Code: **33493**
3. Application Contact Telephone Numbers... Telephone: **(561) 993-1658** ext. Fax: **(561) 992-7326**
4. Application Contact Email Address: **matthew_capone@floridacrystals.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	12-14-05
2. Project Number(s):	0990005-014-AC
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.
☐ Title V air operation permit revision.
☐ Title V air operation permit renewal.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.
☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Application to modify Mill Boiler No. 16 by limiting operation of the boiler to an annual capacity factor of 10 percent.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
014	Okeelanta Mill Boiler No. 16		

Application Processing Fee

Check one: ☐ Attached - Amount: $____________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **Ricardo A. Lima, Vice President and General Manager**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Okeelanta Corporation** Street Address: **21250 U.S. Highway 27** City: **South Bay** State: **FL** Zip Code: **33493**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(561) 993-1600** ext. Fax: **(561) 992-7326**
4.	Owner/Authorized Representative Email Address: **ricardo_lima@floridacrystals.com**
5.	Owner/Authorized Representative Statement:

I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.

RALima 12-9-05

Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - ☐ The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

   ____________________ ____________________
   Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **David A. Buff** Registration Number: **19011**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext.**545** Fax: **(352) 336-6603**
4.	Professional Engineer Email Address: **dbuff@golder.com**
5.	Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David A. Buff — Signature

12/13/05 — Date

(seal)

* Attach any exception to certification statement.

** **Board of Professional Engineers Certificate of Authorization #00001670**

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

<table>
<tr><td colspan="2">1. Facility UTM Coordinates...
Zone 17 East (km) **524.90**
North (km) **2940.10**</td><td colspan="2">2. Facility Latitude/Longitude...
Latitude (DD/MM/SS) **26°35'00"**
Longitude (DD/MM/SS) **80°45'00"**</td></tr>
<tr><td>3. Governmental Facility Code:
0</td><td>4. Facility Status Code:
A</td><td>5. Facility Major Group SIC Code:
20</td><td>6. Facility SIC(s):
2061, 2062, 4911</td></tr>
<tr><td colspan="4">7. Facility Comment :</td></tr>
</table>

Facility Contact

1. Facility Contact Name: **Matthew Capone, Director of Environmental Programs**
2. Facility Contact Mailing Address... Organization/Firm: **Okeelanta Corporation** Street Address: **21250 U.S. Highway 27 South** City: **South Bay** State: **FL** Zip Code: **33493**
3. Facility Contact Telephone Numbers: Telephone: **(561) 993-1658** ext. Fax: **(561) 992-7326**
4. Facility Contact Email Address: **matthew_capone@floridacrystals.com**

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☒ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter Total - PM	A	N
Particulate Matter - PM_{10}	A	N
Sulfur Dioxide - SO_2	A	N
Nitrogen Oxides - NO_x	A	N
Carbon Monoxide - CO	A	N
Volatile Organic Compounds - VOC	A	N
Lead - Pb	B	N
Hydrogen Chloride - H106	A	N
Mercury Compounds - H114	B	N
Total Hazardous Air Pollutants - HAPs	A	N

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID Nos. Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **OC-FI-C1** ☐ Previously Submitted, Date:_____
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **OC-FI-C2** ☐ Previously Submitted, Date:_____
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:_____ ☒ Previously Submitted, Date: **May 20, 2005**

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☒ Attached, Document ID: **OC-FI-CC1** ☐ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction or Modification: ☒ Attached, Document ID: **Part B**
3.	Rule Applicability Analysis: ☒ Attached, Document ID: **Part B**
4.	List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
6.	Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
7.	Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable

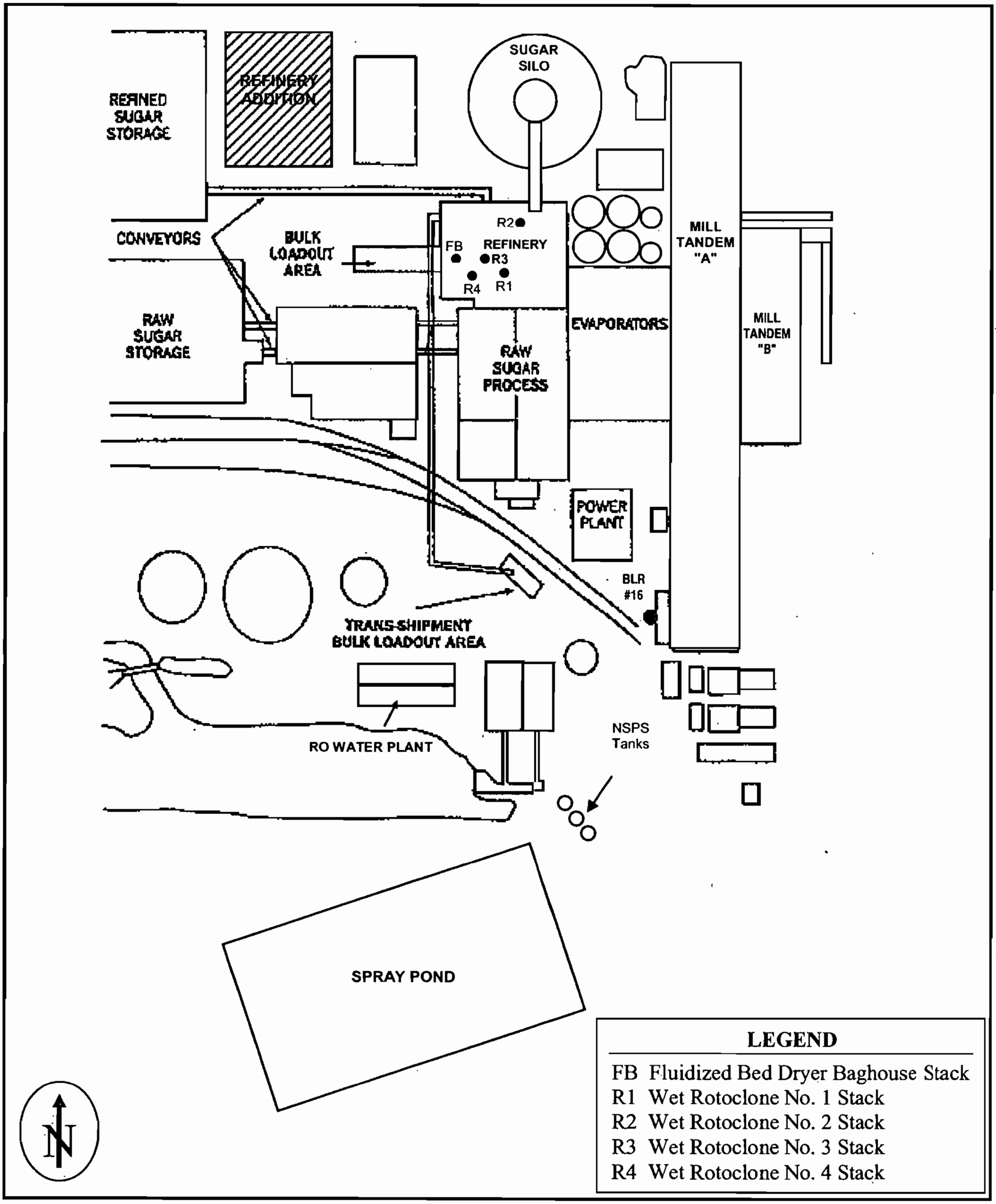
Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:____ ☐ Not Applicable (revision application)
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:____ ☐ Not Applicable (revision application with no change in applicable requirements)
3. Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:____ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☐ Not Applicable
5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:____ ☐ Not Applicable
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:____ ☐ Not Applicable

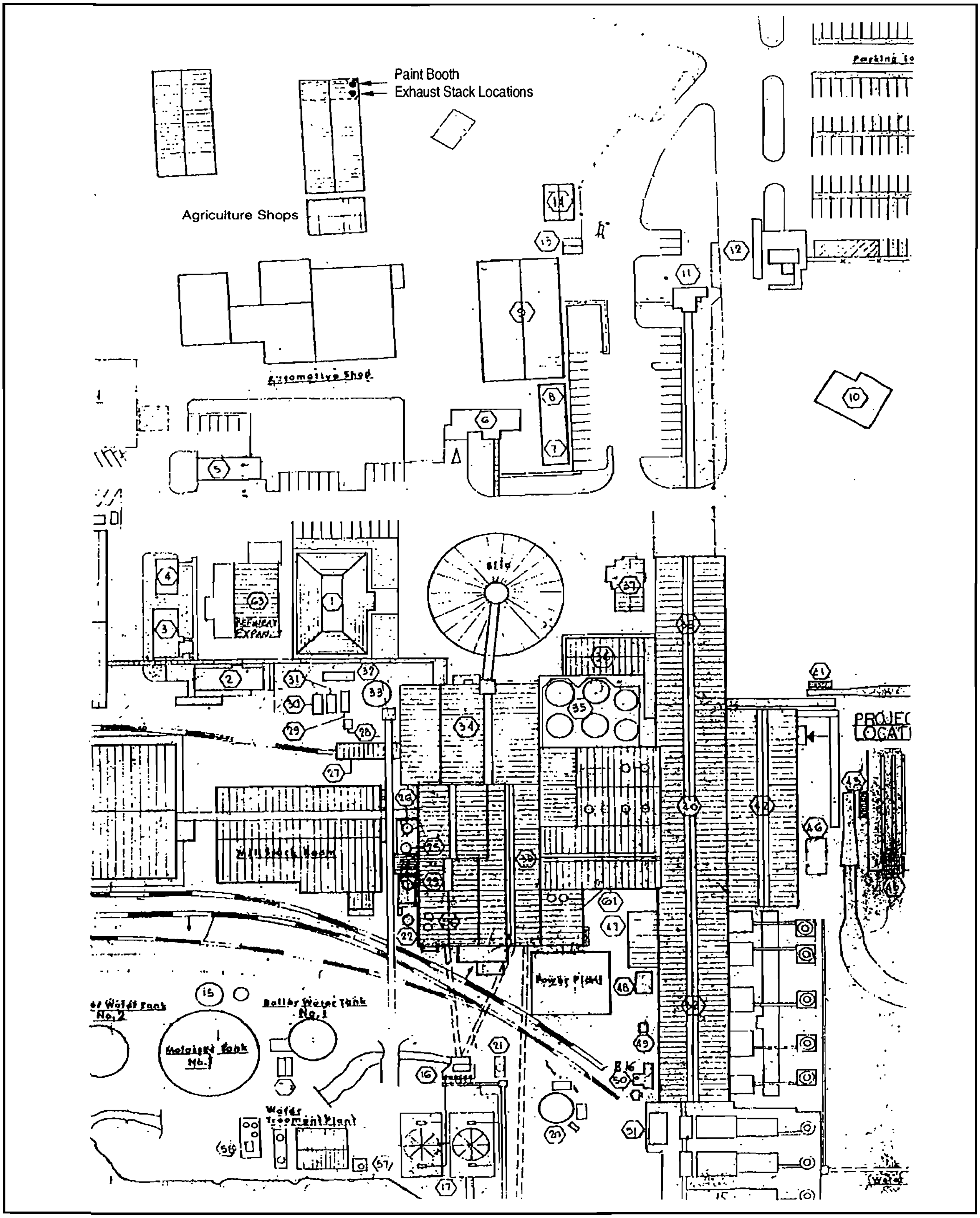
Additional Requirements Comment



Attachment OC-FI-C1a
Facility Plot Plan of Okeelanta Sugar Mill and Refinery

Note: Plot Plan is a general arrangement for informational purposes only. Plot plan is not to scale

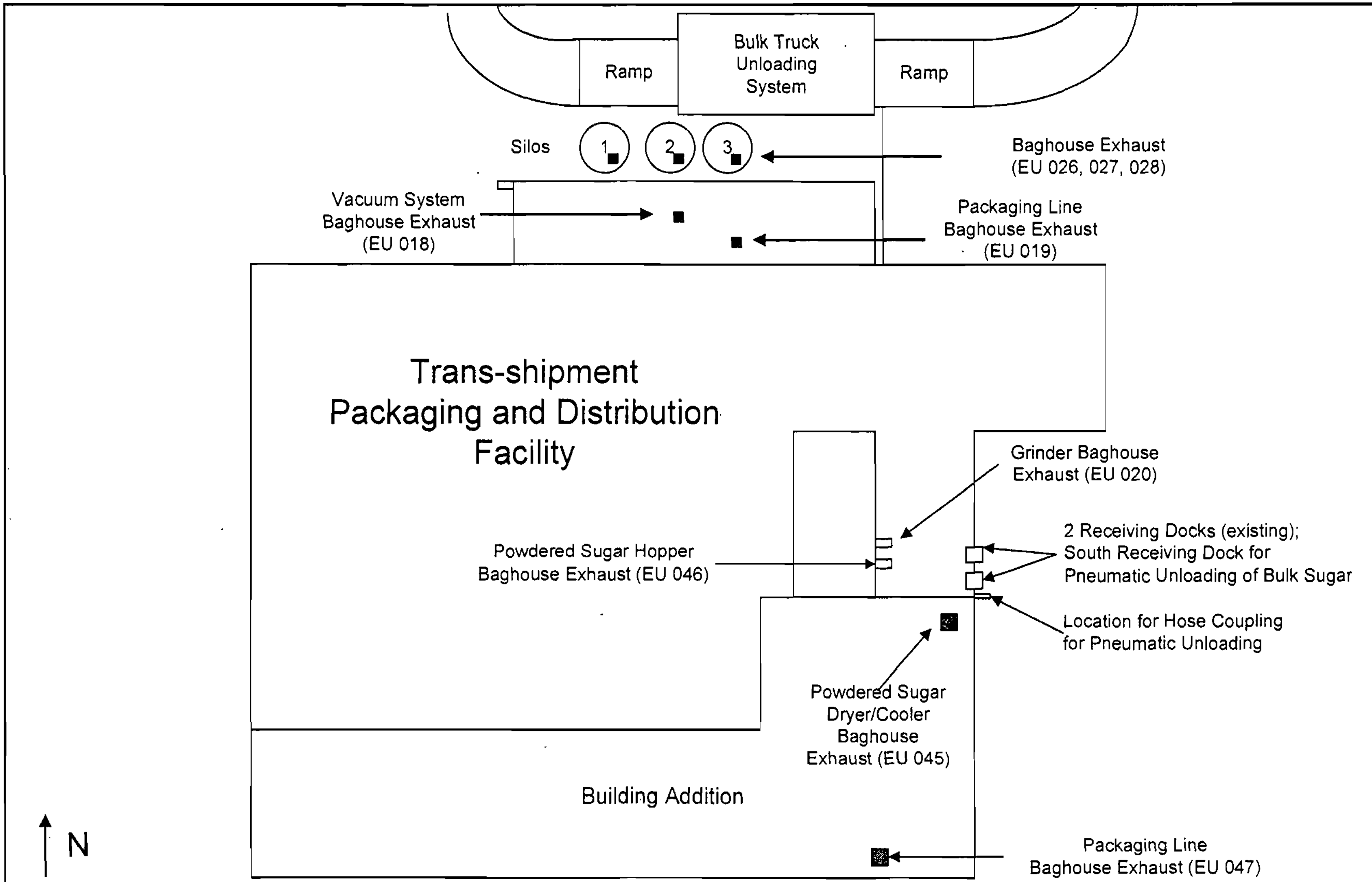
Golder Associates



Attachment OC-FI-C1b
Facility Plot Plan, including Paint Booth

Source: Golder, 2005.

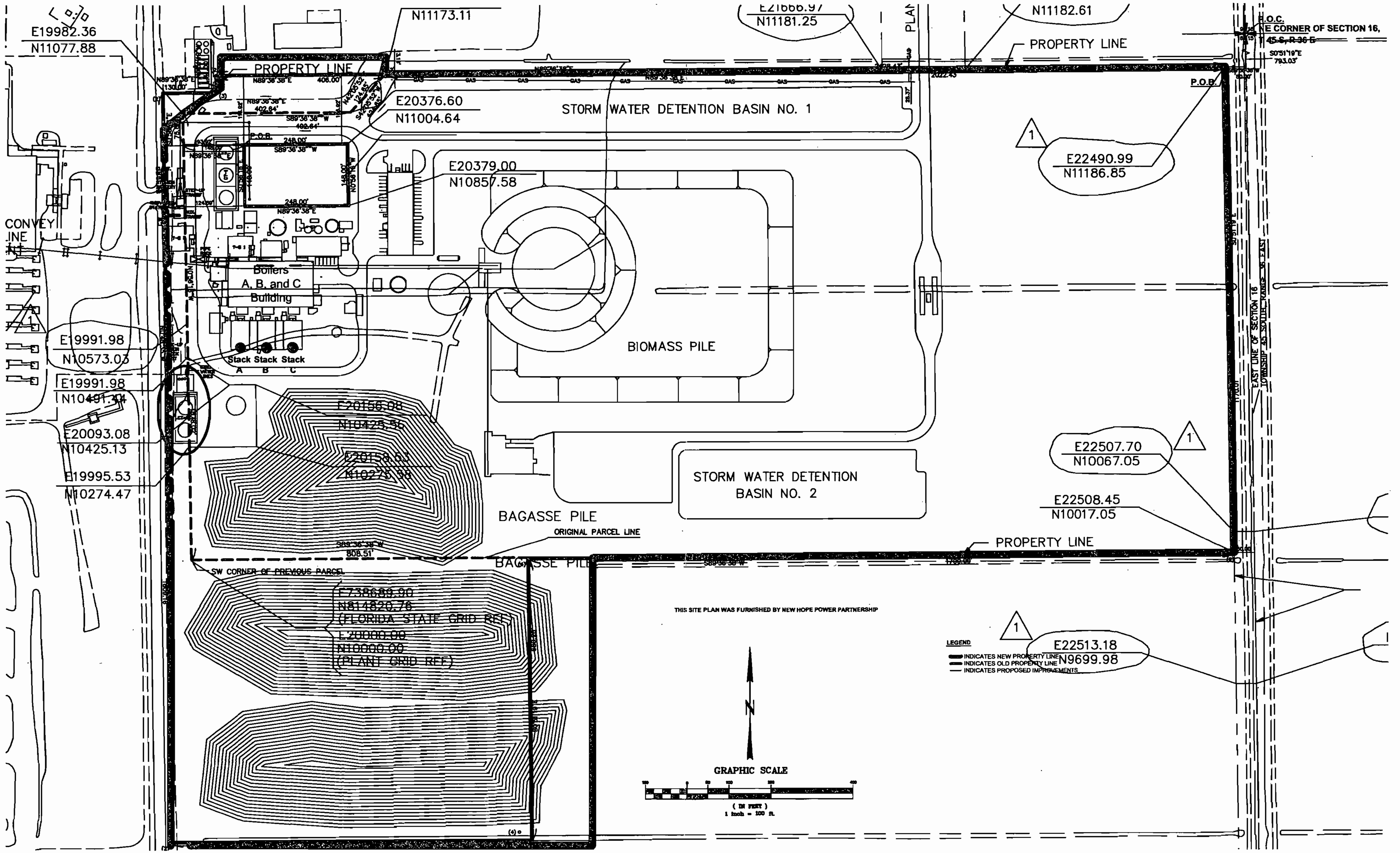
Golder Associates



Plot plan is a general arrangement for informational purposes only. Locations are approximate. Plot plan is not to scale.

Attachment OC-FI-C1c
Trans-shipment Packaging and Distribution
Facility Plot Plan
Okeelanta Corporation

Golder Associates



PAG SURVEYORS, INC. L.B. 3411
1016 SOUTHEAST 4TH STREET
BELLE GLADE, FL 33430-4330 PHONE (561) 996-6615

SEAL

DATE	8-18-03				
SCALE	1"=100'				
DRAWN	SB				
FB No.					
CHECKED	PAG	NO.	REVISIONS	BY	DATE

ATTACHMENT OC-FI-C1d. Facility Plot Plan

NEW HOPE POWER PARTNERSHIP
P.O. BOX 9
SOUTH BAY, FL 33493

PALM BEACH COUNTY, FLORIDA

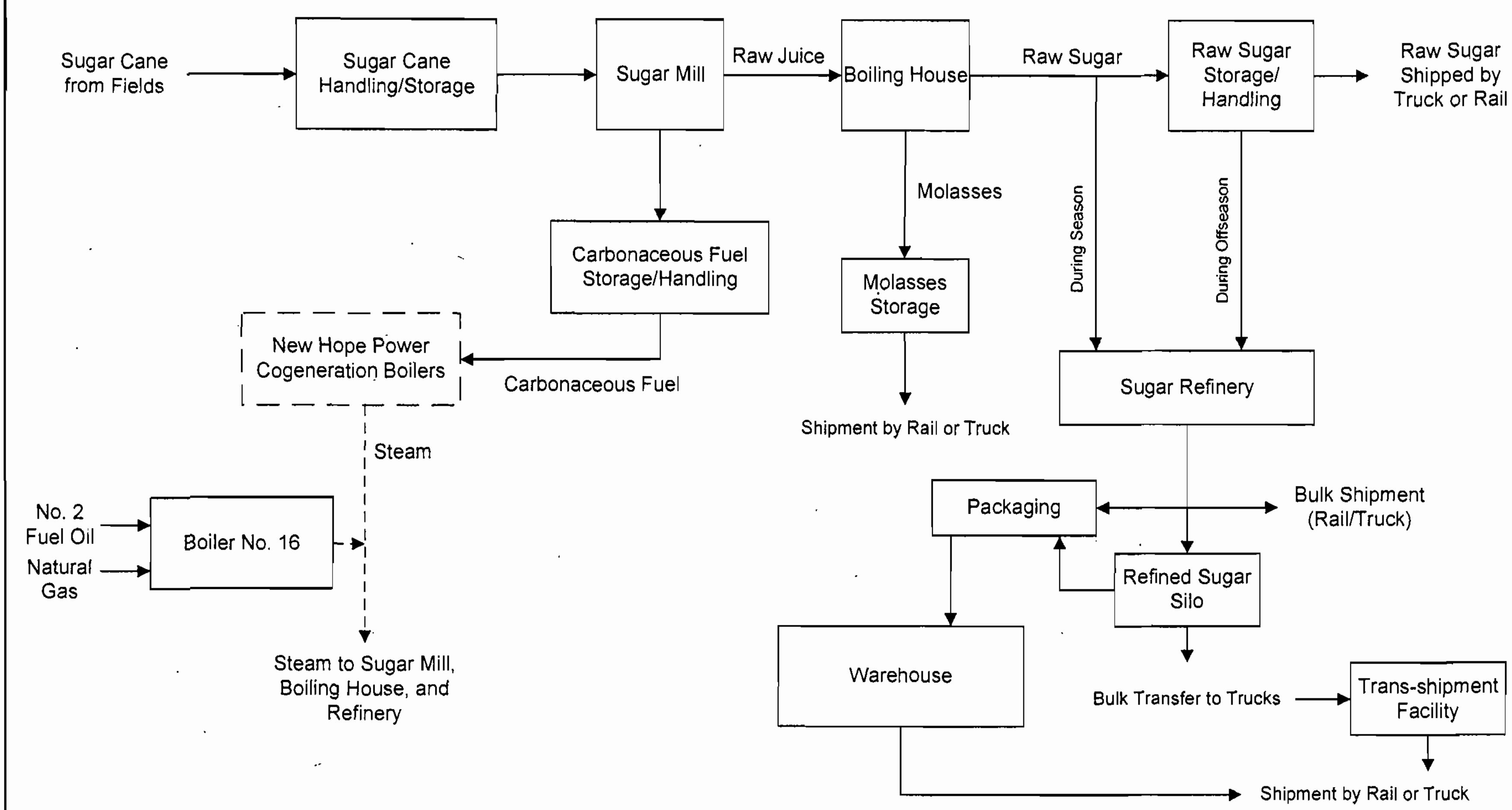
SHEET NO. 1 OF 1

WORK ORDER NO. 03-3-182

0537537/4/4.4/OC-FI-C1c.dwg

ATTACHMENT OC-FI-C2

PROCESS FLOW DIAGRAM

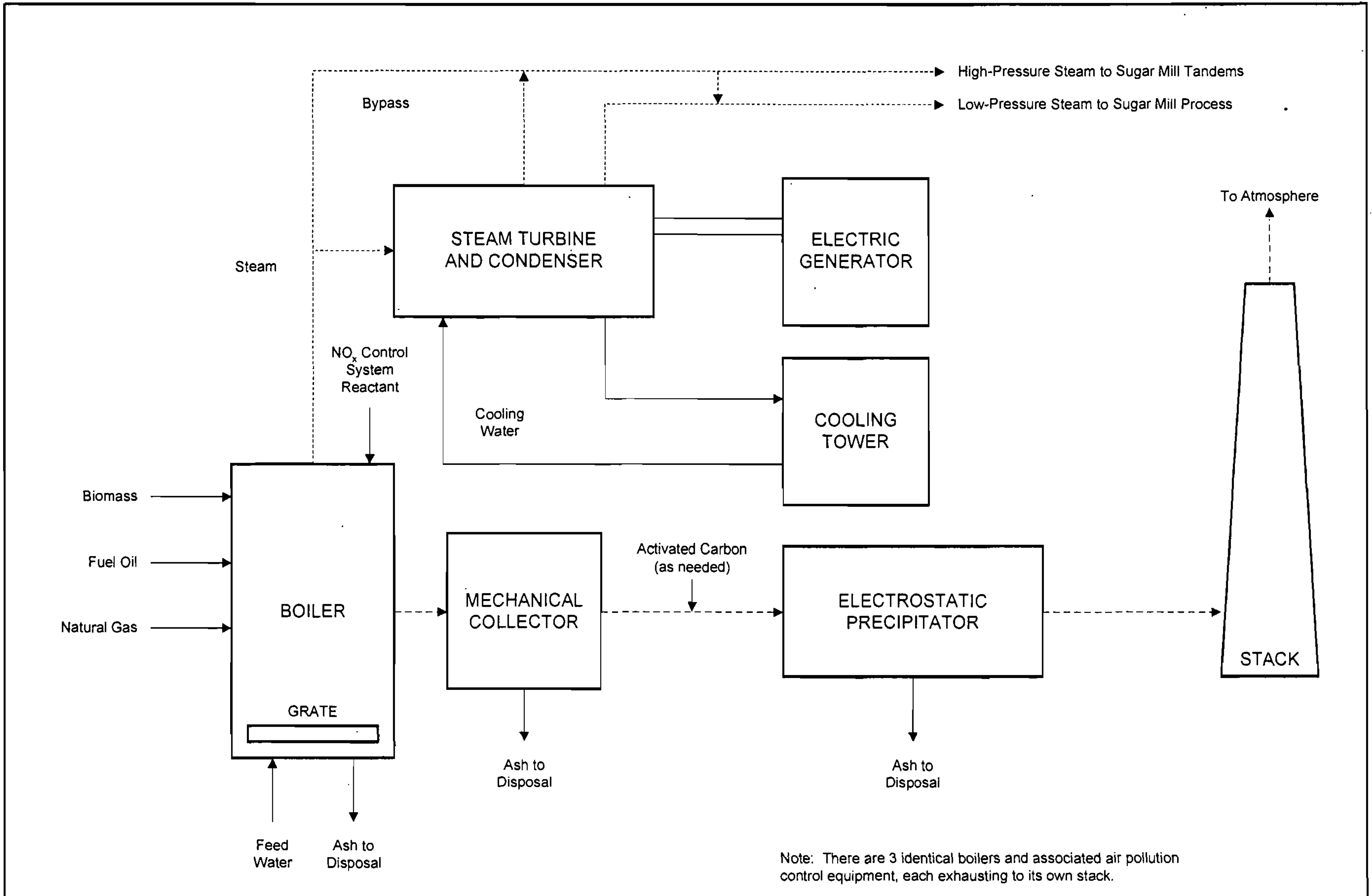


Attachment OC-FI-C2a
Sugar Manufacturing
Process Flow Diagram
Okeelanta Corporation
South Bay, FL

Overall Sugar Mill - Facility Flow Diagram

Process Flow Legend	
Solid/Liquid	——→
Steam	·········→
Gas	- - - - - -→

Golder Associates



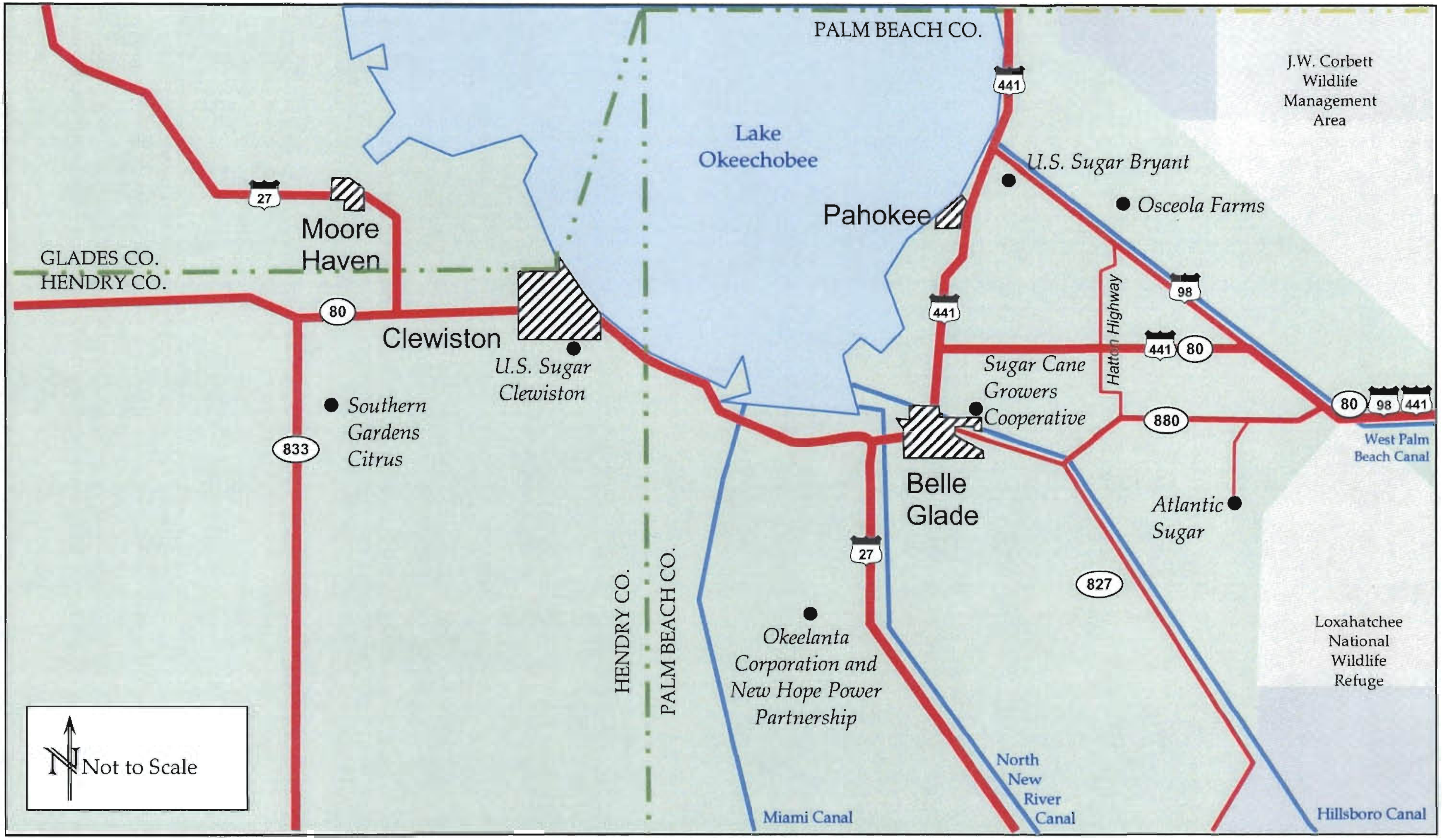
Attachment OC-FI-C2b
Simplified Flow Diagram
New Hope Power Partnership Cogeneration Facility
South Bay, FL

Process Flow Legend
Solid/Liquid
Steam
Gas

Golder Associates

ATTACHMENT OC-FI-CC1

AREA MAP SHOWING FACILITY LOCATION



Attachment OC-FI-CC1
Location of Okeelanta Corporation and New Hope Power Partnership

Source: Golder Associates Inc., 2005.

Golder Associates

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Mill Boiler No. 16

3. Emissions Unit Identification Number: **014**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A			**20**	☐ Yes ☒ No

9. Package Unit:
Manufacturer: **Babcock and Wilcox** Model Number: **FM 120-97**

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
Package Boiler equipped with Low-NO_x burners for No. 2 distillate fuel oil and natural gas. This unit is designed for approximately 15-percent flue gas recirculation.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Low-NO_x Burners** **Flue gas recirculation**	
2. Control Device or Method Code(s): **205, 026**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1.	Maximum Process or Throughput Rate:
2.	Maximum Production Rate: **150,000 lb/hr steam, 24-hour average**
3.	Maximum Heat Input Rate: **211** million Btu/hr
4.	Maximum Incineration Rate: pounds/hr tons/day
5.	Requested Maximum Operating Schedule: **24** hours/day **7** days/week **52** weeks/year **8,760** hours/year
6.	Operating Capacity/Schedule Comment: **Maximum heat input rate represents natural gas burning. The maximum heat input rate for fuel oil is 202 MMBtu/hr. Annual capactiy factor will be limited to 10 percent.**

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **BLR 16**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **75** feet	7. Exit Diameter: **5.0** feet
8. Exit Temperature: **393** °F	9. Actual Volumetric Flow Rate: **118,600** acfm	10. Water Vapor: **9** %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters are based on 2001 stack test data.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Distiillate Oil; Grades 1 and 2 Oil**		
2. Source Classification Code (SCC): **1-02-005-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **1.485**	5. Maximum Annual Rate: **1,301**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **136**
10. Segment Comment: **Based on 202 MMBtu/hr while firing No.2 fuel oil. Maximum Annual Rate based on annual capacity factor of 10 percent.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Natural Gas; Over 100 MMBtu/hr**		
2. Source Classification Code (SCC): **1-02-006-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **0.207**	5. Maximum Annual Rate: **181.2**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,020**
10. Segment Comment: **Based on 211 MMBtu/hr while firing natural gas. Maximum Annual Rate based on annual capacity factor of 10 percent.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			NS
PM_{10}			NS
SO_2			EL
NO_x	205	026	EL
CO			EL
VOC			NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **12.12** lb/hour **5.31** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.06 lb/MMBtu** Reference: **Permit No. 0990005-009-AC**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **See Table 2-1 for calculations.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Maximum emissions based on firing maximum No. 2 fuel oil. Limit applies to both fuel oil and natural gas. Limited annual capacity factor to 10 percent, which is equivalent to a fuel oil usage of 1,301,117 gallons per year.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

<u>Allowable Emissions</u> Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05 percent S**	4. Equivalent Allowable Emissions: **12.12** lb/hour **5.31** tons/year
5. Method of Compliance: **Fuel Analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit is maximum sulfur content of No. 2 fuel oil and a 10 percent annual capacity factor.**	

<u>Allowable Emissions</u> Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

<u>Allowable Emissions</u> Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **42.2** lb/hour **18.48** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.20 lb/MMBtu** Reference: **Permit No. 0990005-009-AC**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **See Table 2-1 for calculations.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Maximum emissions based on natural gas firing. Emission factor applies to both fuel oil firing and natural gas. Annual emissions based on 10 percent annual capacity factor.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **42.2** lb/hour **18.48** tons/year
5. Method of Compliance: **Annual testing using EPA Method 7, 7A, or 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on Permit No. 0990005-009-AC. Limit applies to both fuel oil and natural gas. Annual limit is based on 10 percent annual capacity factor.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **23.21** lb/hour **10.17** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.11 lb/MMBtu** Reference: **Permit No. 0990005-009-AC**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **See Table 2-1 for calculations.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Maximum emissions based on natural gas firing. Emission factor applies to both fuel oil firing and natural gas. Annual emissions based on annual capacity factor of 10 percent.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **EPA Method 9 and Alternative Monitoring Plan for Opactiy (see Attachment OC-EU1-G1)**	
5. Visible Emissions Comment: **40 CFR 60.43b(f). During startup, shutdown, or malfunction, opacity shall not exceed 20 percent, except for one 6-minute period per hour that does not exceed 27 percent.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 3

1. Parameter Code: **Steam Pressure**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Honeywell** Model Number: **DR4500 Truline**	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Existing permit condition requires monitoring of the steam pressure. No serial number or installation date provided because meter is routinely replaced to ensure optimum performance.**	

Continuous Monitoring System: Continuous Monitor 2 of 3

1. Parameter Code: **Steam Production**	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Honeywell** Model Number: **DR4500 Truline**	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Existing permit condition requires monitoring of the steam production. No serial number or installation date provided because meter is routinely replaced to ensure optimum performance.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 3 of 3

1. Parameter Code: **TEMP**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **Honeywell** Model Number: **DR4500 Truline**	Serial Number:
5. Installation Date: **01 OCT 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Existing permit condition requires monitoring of the steam temperature. No serial number provided because meter is routinely replaced to ensure optimum performance.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: OC-EU1-I1 ☐ Previously Submitted, Date _____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: OC-EU1-I2 ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: OC-EU1-I4 ☐ Previously Submitted, Date _____ ☐ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute ☒ Attached, Document ID: Part B ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: _____ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: _____ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: _____ ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____ ☐ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____ ☐ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: _____ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☐ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Not Applicable	

Additional Requirements Comment

ATTACHMENT OC-EU1-G1

BOILER NO. 16
ALTERNATE SAMPLING PROCEDURE FOR OPACITY MONITORING

ATTACHMENT OC-EU1-G1

BOILER NO. 16

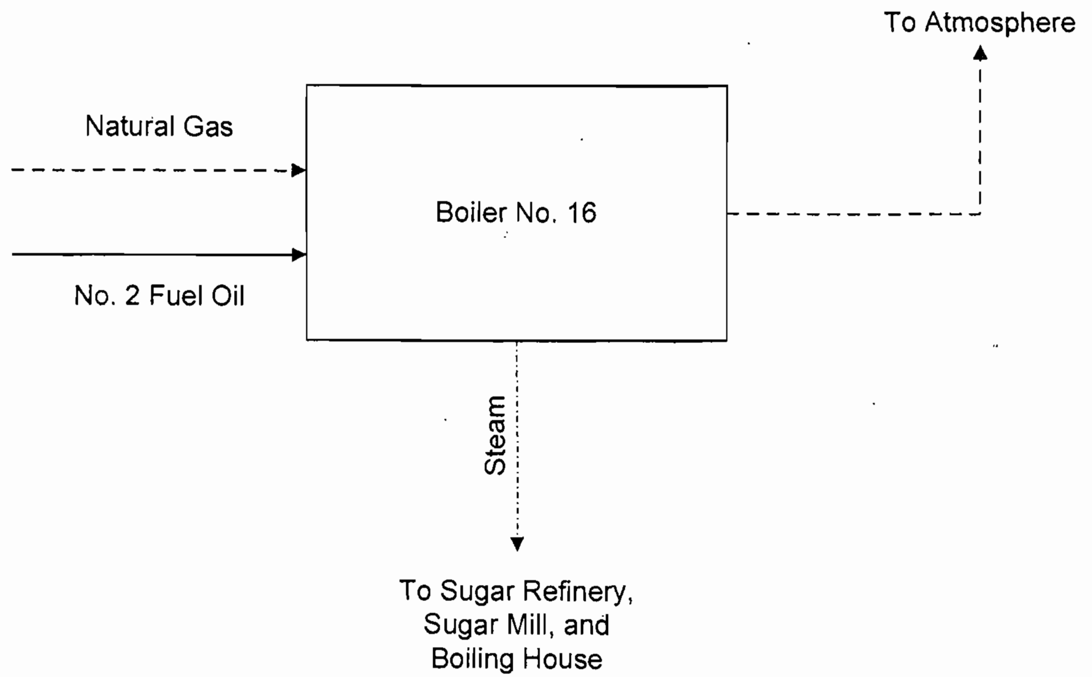
ALTERNATE SAMPLING PROCEDURE FOR OPACITY MONITORING

In accordance with 40 CFR 60, Subpart A, the following procedures are specified in lieu of the requirement for the continuous opacity monitoring requirement under 40 CFR 60.48b(a) for fuel oil firing.

1. Visible Emissions: In lieu of continuous opacity monitoring, the permittee may use the following procedure in order to determine the opacity of emissions when Boiler No. 16 burns distillate fuel oil.
   a. An individual who is trained in the use of EPA Reference Method 9 and is currently certified as a visible emissions observer by the State of Florida shall perform a twelve-minute opacity test once per daylight shift during the period that the highest oil firing rate occurs;
   b. An individual who is trained in the use of EPA Reference Method 9 and is currently certified as a visible emissions observer by the State of Florida shall perform a twelve-minute opacity test when the boiler achieves the normal operational load after a cold boiler startup with distillate fuel oil;
   c. Required observations shall be made in accordance with the provisions of EPA Reference Method 9;
   d. The observer shall maintain a log, which includes all of the information required by EPA Reference Method 9 for each set of observations and the quantity of distillate oil being burned at the time of the observations;
   e. A copy of the observation log shall be submitted to the South District Office of the Department once per calendar quarter if distillate oil was fired during that quarter. Information regarding fuel usage and fuel analysis shall also be submitted to the South District Office on a quarterly basis to verify that the 10 percent annual capacity factor limit is not exceeded;
   f. The permittee shall follow the boiler manufacturer's maintenance schedule and procedure to assure that serviceable components are well maintained, and;
   g. Permittee shall install and operate a continuous opacity monitor if either the annual capacity factor limit of 10 percent for combustion of distillate fuel oil is exceeded, or the applicable visible emission limiting standard in 40 CFR 60.43b(f) is not regularly complied with when Boiler No. 16 is operated on distillate oil.

ATTACHMENT OC-EU1-I1

PROCESS FLOW DIAGRAM



Attachment OC-EU1-I1
Boiler No. 16 - Process Flow Diagram

Okeelanta Corporation - South Bay, FL

Process Flow Legend
Solid/Liquid
Gas
Steam

Golder Associates

ATTACHMENT OC-EU1-I2

DESIGN FUEL SPECIFICATIONS

ATTACHMENT OC-EU1-I2

DESIGN FUEL SPECIFICATIONS FOR BOILER NO. 16[a]

Parameter		No. 2 Fuel Oil	Natural Gas
Specific Gravity		0.865	–
Heating Value	(Btu/lb)	19,175	–
Heating Value	(Btu/gal)	136,000	–
Heating Value	(Btu/scf)	–	1,020
Ultimate Analysis (dry basis percentage):			
Carbon		87.01	82.96
Hydrogen		12.47	5.41
Nitrogen		0.02	1.58
Oxygen		–	5.72
Sulfur		0.05	0.67
Ash/Inorganic		–	3.66
Moisture		–	4.5

[a] Represents average fuel characteristics.

Sources: Okeelanta Corp., 2002.
Combustion Engineering, 1981.

ATTACHMENT OC-EU1-I4

BOILER NO. 16

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT OC-EU1-I4

PROCEDURES FOR STARTUP AND SHUTDOWN
BOILER NO. 16

During startup and shutdown of the boiler, excess emissions for more than 2 hours in a 24-hour period are possible. Pursuant to Rule 62-210.700(1), F.A.C., the following procedures and precautions are taken to minimize the magnitude and duration of excess emissions during startup and shutdown of Boiler No. 16.

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 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(s), e.g., turboalternator, is established, boiler controls are placed in automatic.

Shutdown Procedures

1. Control is turned off and the fuel pump is shut off.
2. The atomizing steam valve is closed. The FD fan is shut off.
3. After about 3 hours, the drum level is set at maximum level.

PART B

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LIST OF ACRONYMS AND ABBREVIATIONS

AAQS	Ambient Air Quality Standards
BACT	Best Available Control Technology
Be	Beryllium
Btu/gal	British thermal units per gallon
Btu/hr-ft^3	British thermal units per hour per cubic feet
Btu/scf	British thermal units per standard cubic feet
CAA	Clean Air Act
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CO	carbon monoxide
COMS	continuous opacity monitoring system
EPA	U.S. Environmental Protection Agency
ENP	Everglades National Park
F.A.C.	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
ft	feet
gal/hr	gallons per hour
gal/yr	gallons per year
GEP	Good Engineering Practice
Hg	mercury
hr/yr	hours per year
km	kilometers
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
m	meters
MMBtu/hr	million British thermal units per hour
MMBtu/yr	million British thermal units per year
MMscf/hr	million standard cubic feet per hour
MMscf/yr	million standard cubic feet per year
NO_2	nitrogen dioxide
NO_x	nitrogen oxides

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LIST OF ACRONYMS AND ABBREVIATIONS (cont'd)

NSPS	New Source Performance Standards
Pb	lead
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter equal to or less than 10 micrometers
PSD	prevention of significant deterioration
RATA	relative accuracy test audit
SAM	sulfuric acid mist
SIP	State Implementation Plan
SO_2	sulfur dioxide
TPY	tons per year
$\mu g/m^3$	micrograms per cubic meter
VE	visible emissions
VOC	volatile organic compounds

1.0 INTRODUCTION

Okeelanta Corporation (Okeelanta) is proposing to revise the annual capacity factor limit of its existing Boiler No. 16, located at the Okeelanta sugar mill south of South Bay, Palm Beach County, Florida. The proposed revision consists of limiting Boiler No. 16 to a 10 percent annual capacity factor, which restricts No. 2 fuel oil usage to 1,301,118 gallons per year (gal/yr) and natural gas usage to 181.2 million standard cubic feet per year (MMscf/yr). The boiler will retain no limits on its annual operating hours [8,760 hours per year (hr/yr)].

Boiler No. 16 is a package boiler with a maximum steam production rate of 150,000 pounds per hour (lb/hr) (24-hour average). It is currently subject to the provisions of the new source performance standards (NSPS), Subpart Db, contained in Title 40 of the Code of Federal Regulations (CFR), Part 60. Under its current permit conditions, the boiler may fire natural gas at up to 211 million British thermal units per hour (MMBtu/hr) for 8,760 hr/yr, or No. 2 fuel oil at up to 202 MMBtu/hr, with an annual restriction on fuel oil firing of 10,000,000 gal/yr. This operation level subjects the boiler to a nitrogen oxide (NO_x) emission standard and an opacity standard under Subpart Db.

Since the boiler is subject to NO_x and opacity limits, Subpart Db requires a continuous emissions monitoring system (CEMS) for NO_x and a continuous opacity monitoring system (COMS) for opacity. Quality assurance requirements for the NO_x CEMS include daily zero and span gas calibrations, and an annual relative accuracy test audit (RATA). Quality assurance requirements for the COMS include daily zero and span calibrations. Quarterly excess emissions and monitor downtime reports for the monitors must be submitted to the Florida Department of Environmental Protection (FDEP). Okeelanta has encountered problems with the NO_x CEMS 7-day drift test as reported in the Quarterly Reports and Annual Statement of Compliance.

During the calendar year 2003, Boiler No. 16 operated only 1,244 hours. During 2004, Boiler No. 16 operated only 20 hours for the sole purpose of performing a RATA for the NO_x CEMS. Boiler No. 16 has not operated during 2005 to date. Therefore, Okeelanta is proposing to limit the annual capacity factor of the boiler in order to exempt Boiler No. 16 from the CEMS requirement for NO_x. By limiting the annual capacity factor to 10 percent, which is equivalent to a maximum heat input of 184,836 million British thermal units per year (MMBtu/yr), the boiler will no longer be subject to a NO_x emissions limit under Subpart Db, and a NO_x CEMS is not required. Okeelanta's Title V permit

(Permit No. 0990005-012-AV), which is currently in the process of being renewed, does not include an annual capacity factor restriction.

Even with the annual capacity factor limitation, Boiler No. 16 is still subject to the opacity limitation, and due to fuel oil firing, the requirement for a COMS under Subpart Db. However, since the most recent construction permit was issued on October 30, 2001 (Permit No. 0990005-009-AC), Boiler No. 16 has not fired any fuel oil. Subpart A, General Provisions of Part 60, provides for alternative monitoring procedures to be requested when the affected facility is infrequently operated [40 CFR 60.13(i)(2)]. The Environmental Protection Agency (EPA) has approved a number of alternative opacity monitoring plans for Subpart Db boilers. These plans require a 12-minute visible observation by a certified visible emissions (VE) reader once per daylight shift during the period that the highest oil-firing rate occurs, and each time the boiler is started from a cold startup and once it achieves normal operational load on fuel oil. Logs must be kept of these operations. This alternative sampling procedure for opacity in lieu of the COMS is proposed for Boiler No. 16 while firing fuel oil.

Through this application, Okeelanta requests that the FDEP limit Boiler No. 16 operation to a 10 percent annual capacity factor, retain the ability to burn both natural gas and fuel oil, drop the requirements for the NO_x CEMS and COMS, and include the alternative sampling procedures described above for opacity when firing fuel oil.

2.0 PROJECT DESCRIPTION

2.1 OVERVIEW

Okeelanta is proposing to revise the operating limits on Boiler No. 16, which currently operates at the Okeelanta sugar mill south of South Bay, Palm Beach County, Florida under Title V Permit No. 0990005-012-AV. Under the current Title V permit, Boiler No. 16 is restricted to 10,000,000 gal/yr of fuel oil and is subject to NSPS, 40 CFR 60, Subpart Db. Subpart Db imposes an emission limit for NO_x and an opacity limit, and requires a CEMS for NO_x and a COMS for opacity. By proposing to limit the annual capacity factor of the boiler to 10 percent, the necessary criteria is met for exemption from the NO_x emission limit and a NO_x CEMS. In addition, an alternate monitoring procedure for opacity for fuel oil firing is proposed based on previous plans approved by EPA.

Boiler No. 16 is an existing package boiler that was originally constructed to provide steam to the Okeelanta sugar refining operations during the off-season. In 1991, a Prevention of Significant Deterioration (PSD) permit (Permit No. PSD-FL-169) was issued, and in 2001, this permit was modified to allow the boiler to fire natural gas and very low sulfur distillate oil (Permit No. PSD-FL-169A/0990005-009-AV). The operation of Boiler No. 16 is unrestricted (8,760 hr/yr).

The proposed revision now requested will restrict the annual capacity factor of the boiler to 10 percent. An annual capacity factor of 10 percent corresponds to an annual heat input of 176,952 MMBtu/yr for No. 2 fuel oil, which is equivalent to 1,301,118 gal/yr of No. 2 fuel oil, or 184,836 MMBtu/yr for natural gas, equivalent to 181.2 MMscf/yr of natural gas. The following sections describe the project in more detail.

2.2 BOILER

2.2.1 CAPACITY

Boiler No. 16 fires pipeline-quality natural gas or very low sulfur No. 2 fuel oil. The maximum heat input rate is 211 MMBtu/hr when firing natural gas, which is approximately 0.207 million standard cubic feet per hour (MMscf/hr) based on a heat content of 1,020 British thermal units per standard cubic feet (Btu/scf). The maximum heat input rate is 202 MMBtu/hr when firing No. 2 fuel oil, which is approximately 1,485 gal/hr based on a heat content of 136,000 British thermal units per gallon (Btu/gal). A 10 percent annual capacity factor is equivalent to 184,836 MMBtu/yr for natural gas firing, and 176,952 MMBtu/yr for No. 2 fuel oil firing based on unrestricted operating hours (8,760 hr/yr). By limiting the boiler to these maximum annual heat inputs, Boiler No. 16 will be restricted to firing 1,301,118 gal/yr of No. 2 fuel oil or 181.2 MMscf/yr of natural gas.

2.2.2 FUELS

Boiler No. 16 has a maximum steam production rate of 150,000 lb/hr and a design heat release rate greater than 70,000 British thermal units per hour per cubic feet (Btu/hr-ft^3). It is fueled with pipeline-quality natural gas or very low sulfur No. 2 fuel oil. The annual capacity for burning No. 2 fuel oil will be limited to 10 percent and the maximum sulfur content for the fuel oil is 0.05 percent.

2.3 AIR POLLUTION CONTROL EQUIPMENT

2.3.1 CONTROLS

The efficient combustion of clean fuels minimizes emissions of carbon monoxide (CO), particulate matter (PM), particulate matter less than 10 microns (PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Emissions of NO_x from Boiler No. 16 are reduced with low NO_x burners, capable of firing pipeline-quality natural gas and very low sulfur No. 2 fuel oil, and flue gas recirculation (approximately 15 percent).

2.3.2 GOOD ENGINEERING PRACTICE

The 1977 Clean Air Act (CAA) Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds Good Engineering Practice (GEP) or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). The FDEP has adopted identical regulations (Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

- 65 meters (m); or
- A height established by applying the formula:

  $$Hg = H + 1.5L$$

  where: Hg = GEP stack height

  H = Height of the structure of nearby structure, and

  L = lesser dimension (height or projected width) of nearby structure(s); or
- A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 kilometers (km). Although GEP stack height regulations require that the stack height used in modeling for determining compliance with Ambient Air Quality Standards (AAQS) and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

The stack for Boiler No. 16 is 75 feet (ft) tall and 5.0 ft in diameter. According to Rule 62-210.555, F.A.C., as defined above, the stack height is less than 65 meters (213.25 ft). Therefore, the boiler will comply with the GEP stack height rule.

2.4 MAXIMUM EMISSIONS

Emissions of CO, PM/PM_{10}, SO_2, and VOC are minimized by the efficient combustion of clean fuels by Boiler No. 16. In addition, emissions of NO_x are reduced with low NO_x burners and flue gas recirculation (approximately 15 percent). Emission-limited pollutants from the boiler include SO_2, NO_x, and CO, which are limited according to Permit No. 0990005-009-AC/PSD-FL-169A under a best available control technology (BACT) determination. By limiting the annual capacity factor to 10 percent, the maximum annual emissions are greatly reduced and PSD review is not triggered for the boiler modification.

The estimated annual emissions from Boiler No. 16 are presented in Table 2-1 for both natural gas and No. 2 fuel oil. By limiting the annual capacity factor for fuel oil firing to 10 percent, the maximum annual heat input to the boiler is limited to 184,836 MMBtu/yr. The maximum annual emissions predicted for either natural gas combustion only or No. 2 fuel oil combustion only include PM/PM_{10} emissions of 2.65 tons per year (TPY), SO_2 emissions of 5.31 TPY, NO_x emissions of 18.48 TPY, CO emissions of 10.17 TPY, VOC emissions of 2.77 TPY, and sulfuric acid mist (SAM) emissions of 0.23 TPY. Lead (Pb), mercury (Hg), and beryllium (Be) maximum annual emissions are all less than 8.0×10^{-4} TPY. For all pollutants except PM, PM_{10}, SO_2, Pb, Hg, and Be, the maximum annual emissions are based on emissions from firing natural gas. Because the emission limited pollutants are below PSD significance levels, and because the emission rates are based on the heat input of the boiler, the natural gas emission factors for NO_x and CO are set equal to the fuel oil emission factors to represent the worst-case fuel, i.e. the fuel oil factor.

The estimated hourly emissions from Boiler No. 16 are also presented in Table 2-1. The maximum heat input for firing natural gas is 211 MMBtu/hr and 202 MMBtu/hr for firing No. 2 fuel oil. The maximum hourly emissions predicted for either natural gas combustion only or No. 2 fuel oil combustion only include PM/PM_{10} emissions of 6.06 lb/hr, SO_2 emissions of 12.12 lb/hr, NO_x

emissions of 42.20 lb/hr, CO emissions of 23.21 lb/hr, VOC emissions of 6.33 lb/hr, and SAM emissions of 0.52 lb/hr. Pb, Hg, and Be maximum hourly emissions are all less than 2.0×10^{-3} lb/hr. For all pollutants except PM, PM_{10}, SO_2, Pb, Hg, and Be, the maximum hourly emissions are based on emissions from firing natural gas. Because the emission limited pollutants are below PSD significance levels, and because the emission rates are based on the heat input of the boiler, the natural gas emission factors for NO_x and CO are set equal to the fuel oil emission factors to represent the worst-case fuel, i.e. the fuel oil factor.

2.5 MONITORING REQUIREMENTS

Due to the limited annual capacity factor of 10 percent, Boiler No. 16 is no longer subject to a NO_x emission limit, and as a result, a NO_x CEMS is no longer required. However, even with the limited annual capacity factor, the boiler is still subject to the opacity limitations and the requirement for a COMS due to fuel oil firing. Since the most recent construction permit was issued on October 30, 2001, Boiler No. 16 has not fired any fuel oil.

Subpart A, General Provisions, of 40 CFR Part 60 provides for alternative monitoring procedures to be requested in lieu of the COMS. Over the years, EPA has approved a number of alternative opacity monitoring plans for Subpart Db boilers. These plans are the basis for the proposed alternate monitoring procedure for Okeelanta Boiler No. 16. This plan is detailed in Attachment OC-EU1-G1 of the permit application and includes a 12-minute visible observation by a certified VE reader once per daylight shift during the period that the highest oil-firing rate occurs, and each time the boiler is started from a cold startup and once it achieves normal operational load on fuel oil. Logs, which include all of the information required by EPA Method 9, shall be maintained by the VE certified individual.

Table 2-1. Maximum Emissions from Boiler No. 16, Okeelanta Corporation

Regulated Pollutant	Natural Gas Combustion: Emission Factor ($lb/10^6$ scf)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor[a] (MMBtu/hr)	Activity Factor[b] (MMBtu/yr)	Hourly Emissions (lb/hr)	Annual Emissions (TPY)	No. 2 Fuel Oil Combustion: Emission Factor (lb/1000 gal)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor[a] (MMBtu/hr)	Activity Factor[b] (MMBtu/yr)	Hourly Emissions (lb/hr)	Annual Emissions (TPY)	Maximum Hourly Emissions Due to Either Fuel[c] (lb/hr)	Maximum Annual Emissions Due to Either Fuel[c] (TPY)
Particulate Matter (PM)	1.9	1.86E-03	1	211	184,836	0.39	0.17	--	0.03	4	202	176,952	6.06	2.65	6.06	2.65
Particulate Matter (PM_{10})	1.9	1.86E-03	1	211	184,836	0.39	0.17	--	0.03	4	202	176,952	6.06	2.65	6.06	2.65
Sulfur dioxide (SO_2)	--	1.00E-03	4	211	184,836	0.21	0.09	7.85	0.06	4	202	176,952	12.12	5.31	12.12	5.31
Nitrogen oxides (NO_x)	--	0.20	7	211	184,836	42.20	18.48	--	0.20	4	202	176,952	40.40	17.70	42.20	18.48
Carbon monoxide (CO)	--	0.11	7	211	184,836	23.21	10.17	--	0.11	4	202	176,952	22.22	9.73	23.21	10.17
Volatile Organic Compounds (VOC)	--	0.03	2	211	184,836	6.33	2.77	--	0.03	2	202	176,952	6.06	2.65	6.33	2.77
Sulfuric acid mist (SAM)	--	6.13E-05	3	211	184,836	1.29E-02	5.66E-03	--	2.57E-03	6	202	176,952	0.52	0.23	0.52	0.23
Lead (Pb)	5.E-04	4.90E-07	1	211	184,836	1.03E-04	4.53E-05	--	9.00E-06	5	202	176,952	1.82E-03	7.96E-04	1.82E-03	7.96E-04
Mercury (Hg)	2.6E-04	2.55E-07	1	211	184,836	5.38E-05	2.36E-05	--	3.00E-06	5	202	176,952	6.06E-04	2.65E-04	6.06E-04	2.65E-04
Beryllium (Be)	1.2E-05	1.18E-08	1	211	184,836	2.49E-06	1.09E-06	--	3.00E-06	5	202	176,952	6.06E-04	2.65E-04	6.06E-04	2.65E-04
Fluorides (Fl)	--	--		--		--	--	--	--		--		--	--	--	--

References:
1. Factors for natural gas combustion from AP-42, Tables 1.4-1, 1.4-2 and 1.4-4 (7/98). Factors were converted to lb/MMBtu by dividing by 1,020 Btu/scf.
2. Based on emission guarantees from vendor.
3. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil. 5% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and gaseous sulfate molecular weights (98/80).
4. Based on Permit No. 0990005-009-AC.
5. Factors for No. 2 fuel oil combustion, AP-42 Table 1.3-1, 1.3-3, and 1.3-10 (9/98). A heating value of 136,000 Btu/gal and a maximum sulfur content of 0.05% were used for the No. 2 fuel oil.
6. The emission factor for SO_3 emissions from a No. 2 fuel fired boiler with low NOx burners (5.7S $lb/10^3$ gal where S is the sulfur content) was multiplied by the ratio of sulfuric acid mist and gaseous sulfate molecular weights (98/80).
7. Natural gas emission factor based on worst-case fuel, i.e. fuel oil factor.

Footnotes:

[a] The maximum permitted heat input rate is 211 MMBtu/hr for natural gas and 202 MMBtu/hr for fuel oil.

[b] Based on 10% annual capacity factor: fuel oil usage of 1,301,118 gal/yr or 176,952 MMBtu/yr and natural gas usage of 181.2 MMscf/yr or 184,836 MMBtu/yr.

[c] Maximum emissions predicted for either natural gas combustion only or No. 2 fuel oil combustion only.

Sample Calculations:

Hourly Emissions = Emission Factor (lb/MMBtu) x Activity Factor (MMBtu/yr)

Annual Emissions = Activity Factor (MMBtu/yr) x Emission Factor (lb/MMBtu) / 2,000 (lb/ton)

Table 2-2.
Summary of Stack Parameters for Boiler No. 16

	Steam Production Rate (lb/hr)	Stack Height (ft)	Stack Diameter (ft)	Gas Parameters Flow Rate (acfm)	Velocity (ft/s)	Temperature (°F)
Boiler No. 16	150,000	75	5	118,600	100.7	393

Notes: acfm = actual cubic feet per minute
°F = degrees Fahrenheit
ft = feet
ft/s = feet per second
lb/hr = pound per hour

3.0 AIR QUALITY REVIEW REQUIREMENTS

The following discussion pertains to federal and state new source review requirements and their applicability to Okeelanta's proposed revision to Boiler No. 16.

3.1 NATIONAL AND STATE AMBIENT AIR QUALITY STANDARDS (AAQS)

The existing applicable national and Florida Ambient Air Quality Standards (AAQS) are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

Florida has adopted State AAQS in Rule 62-204.240, F.A.C. These standards are the same as the national AAQS, except in the case of SO_2. For SO_2, Florida has adopted the former 24-hour secondary standard of 260 micrograms per cubic meter ($\mu g/m^3$) and former annual average secondary standard of 60 $\mu g/m^3$.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the CAA must be reviewed and a pre-construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by the EPA. Therefore, PSD approval authority has been granted to FDEP.

According to PSD regulations, a "major facility" is defined as any one of the 28 named source categories that have the potential to emit 100 TPY or more, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under the CAA. An "emission unit" is defined as any part of activity of a facility that has the potential to emit any air pollutant. "Potential to emit" means the capability, at a maximum design capacity, to emit a pollutant, considering the application of control equipment and any other federally enforceable limitations on the emission units' capacity. A "major modification" is defined under PSD regulations as a change at an existing major stationary facility that increases emissions by greater than significant amounts. PSD significant emission rates are presented in Table 3-2.

Three classifications of areas in which a new source (or modification) will be located or have an impact are designated based on criteria established in the 1990 CAA Amendments. Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21 (Prevention of Significant Deterioration of Air Quality). The State of Florida has adopted PSD regulations that are equivalent to the federal PSD regulations (Rule 62-212.400, F.A.C.).

3.2.2 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that the best available control technology (BACT) be applied to control emissions from the source. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility exceeds the significant emission rate (see Table 3-2).

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with NSPS for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required.

3.3 POTENTIALLY APPLICABLE EMISSION STANDARDS

3.3.1 NEW SOURCE PERFORMANCE STANDARDS

NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the CAA Amendments of 1977, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

Existing non-NSPS sources may become subject to the NSPS if such sources undergo a "modification" or reconstruction". "Modification" means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

"Reconstruction" means the replacement of components of an affected 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.

40 CFR 60.5 defines "fixed capital cost" as the capital needed to provide all the depreciable components. 40 CFR 60.2 defines "capital expenditure" as:

> an expenditure for a physical or operational change to an existing facility which exceeds the project of the applicable "annual asset guideline repair percentage" specified in the latest edition of IRS Publication 534 and the existing facility's basis, as defined by Section 1012 of the IRS Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any "excluded additions" as defined in IRS Publication 534, as would be done for tax purposes.

Federal NSPS exist for fossil fuel industrial-commercial-institutional steam boilers constructed or modified after June 19, 1984 and with a maximum heat input capacity of greater than 100 MMBtu/hr. Boiler No. 16 is subject to NSPS, which are contained in 40 CFR 60, Subpart Db.

3.3.2 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Maximum Achievable Control Technology (MACT) standards, codified in 40 CFR 63, Subpart DDDDD, were promulgated for industrial boilers on September 13, 2004, with an effective date of November 12, 2004. Subpart DDDDD, also known as the Industrial, Commercial, and Institutional Boiler and Process Heater MACT, regulates HAP metals (with PM as a surrogate), hydrogen chloride, and mercury emissions for new or reconstructed large and limited-use liquid fuel-fired industrial boilers. The compliance date for existing boilers is September 13, 2007.

Existing MACT sources may become subject to new source MACT if such sources are "reconstructed". In the General Provisions for the MACT Rules, 40 CFR 63, Subpart A, "reconstruction" is defined as follows:

> Reconstruction, unless otherwise defined in a relevant standard, means the replacement of components of an affected or previously non-affected source 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 new source; and
> 2) It is technologically and economically feasible for the reconstructed source to meet the relevant standard(s) established by the Administrator pursuant to Section 112 of the Act. Upon reconstruction, an affected source, or a stationary source that becomes an affected source, is subject to relevant standards for new sources, including compliance dates, irrespective of any change in emissions of hazardous air pollutants from that source.

Since Okeelanta Boiler No. 16 is not a new or "reconstructed" boiler, but will become an existing limited-use liquid fuel boiler with the restrictions being proposed in this application, it will only be subject to the initial notification requirements in 40 CFR 63.9(b) and not subject to any emission limits [40 CFR 63.7506(b)].

3.3.3 FLORIDA RULES

Emission limitations applicable to fossil fuel generators with less than 250 MMBtu/hr of heat input are contained in Rule 62-296.406, F.A.C. This rule requires that "existing" fossil fuel steam generators meet a visible emissions limit of 20 percent opacity, except for either one six-minute period per hour during which opacity does not exceed 27 percent, or one two-minute period per hour during which opacity does not exceed 40 percent. PM and SO_2 emissions are subject to BACT.

3.4 <u>SOURCE APPLICABILITY</u>

3.4.1 AREA CLASSIFICATION

The project site is located in Palm Beach County, which has been designated by EPA and FDEP as an attainment or maintenance area for all criteria pollutants. Palm Beach County and the surrounding counties are designated as PSD Class II areas for SO_2, PM_{10}, and NO_2. The nearest Class I area to the site is the Everglades National Park (ENP), located about 92 km (57 miles) south of the Okeelanta facility.

3.4.2 PSD REVIEW

3.4.2.1 Pollutant Applicability

The existing Okeelanta facility is considered to be a major facility under the category "Fossil fuel fired boilers (or combinations thereof) totaling more than 250 MMBtu/hr of heat input" as listed in Table 212.400-1, F.A.C. Therefore, PSD review is required for any pollutant for which the increase in emissions due to the modification is greater than the PSD significant emission rates. For the proposed Boiler No. 16 modification, which includes an annual capacity factor limit of 10 percent, there is no increase in any pollutant emissions due to the modification, and therefore, no PSD review is required.

3.4.3 EMISSION STANDARDS

3.4.3.1 New Source Performance Standards

Based on a maximum heat input of greater than 100 MMBtu/hr, Boiler No. 16 is subject to the federal NSPS for Industrial, Commercial, Institutional Steam Generating Units (40 CFR 60, Subpart Db). Subpart Db regulates PM, SO_2 and NO_x emissions. However, due to the fuels Boiler No. 16 will fire, and the 10 percent annual capacity factor limitation, only an opacity standard will apply to Boiler No. 16. Subpart Db requires a COMS for opacity. Quality assurance requirements for the COMS include daily zero and span calibrations. Quarterly excess emissions and monitor downtime reports for the monitors must be submitted to the FDEP.

Subpart A, General Provisions, of Part 60, provides for alternative monitoring procedures to be requested when the affected facility is infrequently operated [40 CFR 60.13(i)(2)]. The EPA has approved a number of alternative opacity monitoring plans for Subpart Db boilers. These plans require a 12-minute visible observation by a certified VE reader once per daylight shift during the period that the highest oil-firing rate occurs, and each time the boiler is started from a cold startup and once it achieves normal operational load on fuel oil. Logs must be kept of these operations. This alternative sampling procedure for opacity in lieu of the COMS is proposed for Boiler No. 16.

3.4.3.2 NESHAPs for Source Categories

Okeelanta Boiler No. 16 is only subject to the initial notification requirements in 40 CFR 63, Subpart DDDDD for Industrial, Commercial, and Institutional Boilers and Process Heaters.

3.4.3.3 State of Florida Standards

Okeelanta Boiler No. 16 is subject to Rule 62-296.406 (BACT), F.A.C. Rule 62-296.406 (BACT) regulates existing fossil fuel steam generators with less than 250 MMBtu/hr and contains standards for PM and SO_2. The standard applicable to Boiler No. 16 requires that BACT must be used to limit emissions. When firing natural gas, the expected maximum SO_2 emissions are 0.001 lb/MMBtu, and when firing very low sulfur No. 2 oil, the expected maximum SO_2 emissions are 0.06 lb/MMBtu. When firing natural gas, the expected maximum PM emissions are 0.0019 lb/MMBtu, and when firing very low sulfur No. 2 oil, the expected maximum PM emissions are 0.03 lb/MMBtu. These low emission rates represent BACT for Boiler No. 16.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels (µg/m³)

Pollutant	Averaging Time	AAQS National Primary Standard	AAQS National Secondary Standard	AAQS State of Florida	PSD Increments Class I	PSD Increments Class II	Significant Impact Levels[d] Class I (proposed)	Significant Impact Levels[d] Class II
Particulate Matter[a]	Annual Arithmetic Mean	50	50	50	4	17	0.2	1
(PM_{10})	24-Hour Maximum[b]	150[b]	150[b]	150[b]	8	30	0.3	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	0.1	1
	24-Hour Maximum[e]	365[b]	NA	260[b]	5	91	0.2	5
	3-Hour Maximum[b]	NA	1,300[b]	1,300[b]	25	512	1	25
Carbon Monoxide	8-Hour Maximum[b]	10,000[b]	10,000[b]	10,000[b]	N/A	N/A	N/A	500
	1-Hour Maximum[b]	40,000[b]	40,000[b]	40,000[b]	N/A	N/A	N/A	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	0.1	1
Ozone[a]	1-Hour Maximum	235[c]	235[c]	235[c]	N/A	N/A	N/A	N/A
	1-Hour Maximum	235	235	NA	N/A	N/A	N/A	N/A
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	N/A	N/A	N/A	N/A

Note: NA = Not applicable, *i.e.*, no standard exists.

PM_{10} = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.

[a] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour standard of 65 µg/m³ (3-year average of 98th percentile) and an annual standard of 15 µg/m³ (3-year average at community monitors). The ozone standard was modified to be 0.08 ppm (157 µg/m³) for 8-hour average; achieved when 3-year average of 99th percentile is 0.08 ppm or less. FDEP has not yet adopted either of these standards.

[b] Short-term maximum concentrations are not to be exceeded more than once per year except for the PM_{10} AAQS (these do not apply to significant impact levels). The PM_{10} 24-hour AAQS is attained when the expected number of days per year with a 24-hour concentration above 150 µg/m³ is equal to or less than 1. For modeling purposes, compliance is based on the sixth-highest 24-hour average value over a 5-year period.

[c] Achieved when the expected number of days per year with concentrations above the standard is fewer than 1.

[d] Maximum concentrations.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978; 40 CFR 50; 40 CFR 52.21; Rule 62-204, F.A.C.

Table 3-2. PSD Significant Emission Rates and *De Minimis* Monitoring Concentrations

Pollutant	Significant Emission Rate (TPY)	De Minimis Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	40	13, 24-hour
Particulate Matter [PM(TSP)]	25	NA
Particulate Matter (PM_{10})	15	10, 24-hour
Nitrogen Dioxide	40	14, annual
Carbon Monoxide	100	575, 8-hour
Volatile Organic Compounds (Ozone)	40	100 TPY[b]
Lead	0.6	0.1, 3-month
Sulfuric Acid Mist	7	NM
Total Fluorides	3	0.25, 24-hour
Total Reduced Sulfur	10	10, 1-hour
Reduced Sulfur Compounds	10	10, 1-hour
Hydrogen Sulfide	10	0.2, 1-hour
Mercury	0.1	0.25, 24-hour
MWC Organics	3.5×10^{-6}	NM
MWC Metals	15	NM
MWC Acid Gases	40	NM
MSW Landfill Gases	50	NM

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below *de minimis* monitoring concentrations.

NA = Not applicable.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
$\mu g/m^3$ = micrograms per cubic meter.
MWC = Municipal waste combustor
MSW = Municipal solid waste

[a] Short-term concentrations are not to be exceeded.
[b] No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.

Sources: 40 CFR 52.21.
Rule 62-212.400, F.A.C.

4.0 REFERENCES

U.S. Environmental Protection Agency (EPA). 1985a. Guideline for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations) (Revised). Research Triangle Park, NC. EPA-450/4-80-023.

ATTACHMENT A

ATTACHMENT A

EU ID 014 : Mill Boiler No. 16 Rule Applicability for Okeelanta Corporation

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart A	40CFR60.1	Subpart A -- General Provisions	
APPLICABLE	60 Subpart A	40CFR60.7	Notification and Record Keeping	
APPLICABLE	60Subpart A	40CFR60.8	Performance Testing	
APPLICABLE	60 Subpart A	40CFR60.11	Compliance with standards and maintenance requirements.	
APPLICABLE	60 Subpart A	40CFR60.12	Circumvention.	
APPLICABLE	60 Subpart A	40CFR60.13	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.13(a)	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.13(b)	Monitoring requirements.	
NON-APPLICABLE	60 Subpart A	40CFR60.13(c)	Monitoring requirements.	Alternate monitoring procedure instead of COMs for opacity.
APPLICABLE	60 Subpart A	40CFR60.13(i)	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.19	General notification and reporting requirements	
NON-APPLICABLE	60 Subpart Da	40CFR60.40a	Subpart Da - NSPS for Electric Utility Units for which construction commenced after Sept. 18, 1978.	Boiler No. 16 is not an electric utility unit.
APPLICABLE	60 Subpart Db	40CFR60.40b	Subpart Db - Applicability and delegation of authority	
APPLICABLE	60 Subpart Db	40CFR60.42b	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Db	40CFR60.42b(a)		
NON-APPLICABLE	60 Subpart Db	40CFR60.42b(c)		Boiler No. 16 does not combust coal and oil as part of a combined cycle system.
NON-APPLICABLE	60 Subpart Db	40CFR60.42b(d)		Boiler No. 16 does not combust coal refuse alone.
APPLICABLE	60 Subpart Db	40CFR60.42b(e)		
NON-APPLICABLE	60 Subpart Db	40CFR60.42b(f)		Boiler No. 16 combusts oil and natural gas.
APPLICABLE	60 Subpart Db	40CFR60.42b(g)		
NON-APPLICABLE	60 Subpart Db	40CFR60.42b(h)		Boiler No. 16 does not use a fuel pretreatment to reduce sulfur dioxide emissions.
NON-APPLICABLE	60 Subpart Db	40CFR60.42b(i)		Boiler No. 16 does not use a sulfur dioxide control system.
APPLICABLE	60 Subpart Db	40CFR60.42b(j)		
APPLICABLE	60 Subpart Db	40CFR60.43b	Standard for particulate matter	
NON-APPLICABLE	60 Subpart Db	40CFR60.43b(a)		Boiler No. 16 does not combust coal.
NON-APPLICABLE	60 Subpart Db	40CFR60.43b(b)		Facility does not use conventional or emerging technology to reduce sulfur dioxide emissions.
NON-APPLICABLE	60 Subpart Db	40CFR60.43b(c)		Boiler No. 16 does not combust wood.
NON-APPLICABLE	60 Subpart Db	40CFR60.43b(d)		Boiler No. 16 does not combust municipal type solid waste.
NON-APPLICABLE	60 Subpart Db	40CFR60.43b(e)		Boiler No. 16 does not combust coal, wood, or municipal-type solid waste.
APPLICABLE	60 Subpart Db	40CFR60.43b(f)		
APPLICABLE	60 Subpart Db	40CFR60.43b(g)		
APPLICABLE	60 Subpart Db	40CFR60.44b	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Db	40CFR60.44b(k)		
NON-APPLICABLE	60 Subpart Db	40CFR60.44b(l)		Facility commenced construction/modification before July 9, 1997.
APPLICABLE	60 Subpart Db	40CFR60.45b	Compliance and performance test methods and procedures for sulfur dioxide	
APPLICABLE	60 Subpart Db	40CFR60.45b(a)		
APPLICABLE	60 Subpart Db	40CFR60.45b(j)		
APPLICABLE	60 Subpart Db	40CFR60.46b	Compliance and performance test methods and procedures for particulate matter and nitrogen oxides	Boiler No. 16 is subject to opacity standards.
APPLICABLE	60 Subpart Db	40CFR60.46b(a)		
APPLICABLE	60 Subpart Db	40CFR60.46b(d)		
APPLICABLE	60 Subpart Db	40CFR60.46b(d)(7)		EPA Method 9 is used for opacity.
APPLICABLE	60 Subpart Db	40CFR60.47b	Emission monitoring for sulfur dioxide	
APPLICABLE	60 Subpart Db	40CFR60.47b(f)		
APPLICABLE	60 Subpart Db	40CFR60.48b	Emission monitoring for particulate matter and nitrogen oxides	
APPLICABLE	60 Subpart Db	40CFR60.48b(a)	Continuous opacity monitor required	An alternative monitoring procedure is requested instead of a COMS.

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APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart Db	40CFR60.48b(i)		
APPLICABLE	60 Subpart Db	40CFR60.49b	Reporting and recordkeeping requirements	
APPLICABLE	60 Subpart Db	40CFR60.49b(a)		
NON-APPLICABLE	60 Subpart Db	40CFR60.49b(b)		No CEMS required.
NON-APPLICABLE	60 Subpart Db	40CFR60.49b(c)		Boiler No. 16 not subject to nitrogen oxide limits set forth in 40CFR60.44b.
APPLICABLE	60 Subpart Db	40CFR60.49b(d)		
NON-APPLICABLE	60 Subpart Db	40CFR60.49b(e)		Boiler No. 16 does not burn No. 6 oil.
APPLICABLE	60 Subpart Db	40CFR60.49b(f)		
NON-APPLICABLE	60 Subpart Db	40CFR60.49b(g)		Boiler No. 16 not subject to nitrogen oxide limits set forth in 40CFR60.44b.
APPLICABLE	60 Subpart Db	40CFR60.49b(h)		
APPLICABLE	60 Subpart Db	40CFR60.49b(h)(1)		
NON-APPLICABLE	60 Subpart Db	40CFR60.49b(i)		No continuous monitoring requirements for nitrogen oxides required.
APPLICABLE	60 Subpart Db	40CFR60.49b(j)		
NON-APPLICABLE	60 Subpart Db	40CFR60.49b(k)		
NON-APPLICABLE	60 Subpart Db	40CFR60.49b(l)		
NON-APPLICABLE	60 Subpart Db	40CFR60.49b(m)		Minimim amount of data obtained during reporting period.
NON-APPLICABLE	60 Subpart Db	40CFR60.49b(n)		Fuel pretreatment not used.
APPLICABLE	60 Subpart Db	40CFR60.49b(o)		
APPLICABLE	60 Subpart Db	40CFR60.49b(r)		
APPLICABLE	60 Subpart Db	40CFR60.49b(v)		
APPLICABLE	63 Subpart A	40 CFR 63.9(b)	Subpart DDDDD - NESHAP for Industrial, Commercial, and Institutional Boiler and Process Heaters - Notification Requirements	Boiler is an existing limited-use liquid fuel unit and subject to notification requirements only.
APPLICABLE	63 Subpart DDDDD	40 CFR 63.7506(b)	Subpart DDDDD - NESHAP for Industrial, Commercial, and Institutional Boiler and Process Heaters	Boiler is an existing limited-use liquid fuel unit and subject to notification requirements only.
APPLICABLE	62-204	62-204.8(b)3.	NSPS Subpart Db adopted by reference.	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
NON-APPLICABLE	62-296 <	62-296.405	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	Boiler No. 16 has a heat input of <250 MMBtu/hr
APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	
NON-APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	Boiler No. 16 was subject to PSD/BACT for Nox emissions.
NON-APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facility	Boiler No. 16 was subject to PSD/BACT for Nox emissions.
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	Okeelanta is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	Okeelanta is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	62-297	62-297	STATIONARY SOURCES - EMISSIONS MONITORING	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.310(1)	Required number of test runs.	
APPLICABLE	62-297	62-297.310(2)	Operating rate during testing.	
APPLICABLE	62-297	62-297.310(3)	Calculation of emission rate.	
APPLICABLE	62-297	62-297.310(4)	Applicable test procedures.	
APPLICABLE	62-297	62-297.310(5)	Determination of process variables.	
APPLICABLE	62-297	62-297.310(6)	Required stack sampling facilities.	
APPLICABLE	62-297	62-297.310(7)	Frequency of compliance tests.	
APPLICABLE	62-297	62-297.310(8)	Test reports.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	

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APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(6)	EPA Method 5 - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(10)	EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources - 40 CFR 60	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 22 - Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(41)	EPA Method 201 - Determination of PM10 Emissions (Exhaust Gas Recycle Procedure) - 40 CFR 51	
APPLICABLE	62-297	62-297.401(41)(a)	EPA Method 201 - Determination of PM10 Emissions (Exhaust Gas Recycle Procedure) - 40 CFR 51	
	62-297	62-297.620	Exceptions and Approval of Alternate Procedures and Requirements.	