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BUREAU OF AIR REGULATION

PSD PERMIT APPLICATION TO MODIFY BOILER NO. 16

OKEELANTA CORPORATION SOUTH BAY, FLORIDA

Prepared For:

Okeelanta Corporation
21250 U.S. Highway 27
South Bay, Florida 33493

Prepared By:

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

March 2001
0037593Y/F1

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6 Copies – FDEP, Tallahassee
2 Copies – Okeelanta Corporation
1 Copy - Golder Associates Inc.

PART A

AIR PERMIT APPLICATION

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Okeelanta Corporation**	
2. Site Name: **Okeelanta Sugar and Refinery Mill**	
3. Facility Identification Number: **0990005** [ ] Unknown	
4. Facility Location: Street Address or Other Locator: **6 Miles South of South Bay on US 27** City: **South Bay** County: **Palm Beach** Zip Code: **33493**	
5. Relocatable Facility? [ ] Yes [**X**] No	6. Existing Permitted Facility? [**X**] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **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) 996 - 9072 x 1658** Fax: **(561) 992-8212**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3/23/01
2. Permit Number:	0990005-017-AC
3. PSD Number (if applicable):	PSD-FL-316
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: ________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: ________________

Operation permit number to be revised: ________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected: ________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised: ________________

Reason for revision: ________________

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[**X**] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **Ricardo A. Lima, Vice President - General Manager**
2.	Owner/Authorized Representative or Responsible Official 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 or Responsible Official Telephone Numbers: Telephone: (**561**) **996 - 9072** Fax: (**561**) **992 - 7326**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [X], if so) of the Title V source addressed in this application, whichever is applicable. 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. 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 any permitted emissions unit.* [signature] 3-21-01 Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **David 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** Fax: (**352**) **336 - 6603**

4. 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.

If the purpose of this application is to obtain a Title V source 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 schedule is submitted with this application.

*If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [**X**], 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.*

If the purpose of this application is to obtain an initial air operation permit or operation permit revision 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

3/21/01
Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
014	Boiler No. 16	AC1A	

Application Processing Fee

Check one: [X] Attached - Amount: $: 7,500 [ ] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations: **To convert Boiler No. 16 to a dual fired unit capable of burning No. 2 fuel oil and natural gas and increase operation to 8,760 hours.**	
2. Projected or Actual Date of Commencement of Construction	**16 Apr 2001**
3. Projected Date of Completion of Construction:	**01 Apr 2003**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **524.90**	North (km): **2940.10**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **26 / 35 /**		Longitude (DD/MM/SS): **80 / 45 /**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **20**	6. Facility SIC(s): **2061, 2062, 4911**
7. Facility Comment (limit to 500 characters): **See Attachment OC-FI-A7.**			

Facility Contact

1. Name and Title of Facility Contact: **Matthew Capone, Director of Environmental Programs**
2. Facility Contact Mailing Address: Organization/Firm: **Okeelanta Corporation** Street Address: **21250 U.S. Highway 27** City: **South Bay** State: **FL** Zip Code: **33493**
3. Facility Contact Telephone Numbers: Telephone: **(561) 996 - 9072 x 1658** Fax: **(561) 992 - 8212**

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [X] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): **See Attachment OC-AI-AD**	

List of Applicable Regulations

See attached Title V Core List, eff. 3/25/97	

Title V Core List

Effective:03/25/97

[**Note:** The Title V Core List is intended to simplify the completion of the "List of Applicable Regulations" that apply facility-wide (see Subsection II.B. of DEP Form No. 62-210.900(1), Application for Air Permit - Long Form. The Title V Core List is a list of rules to which all Title V Sources are presumptively subject. The Title V Core List may be referenced in its entirety, or with specific exceptions. The Department may periodically update the Title V Core List.

Requirements that apply to emissions units must be identified in Subsection III.B. of DEP Form No. 62-210.900(1), Application for Air Permit - Long Form.

Applicants must identify all "applicable requirements" in order to claim the "permit shield" described at Rule 62-213.460, F.A.C.]

Federal: ***(description)***

40 CFR 61: National Emission Standards for Hazardous Air Pollutants (NESHAP)
40 CFR 61: Subpart M: NESHAP for Asbestos.
40 CFR 64: Compliance Assurance Monitoring
40 CFR 82: Protection of Stratospheric Ozone.
40 CFR 82: Subpart B: Servicing of Motor Vehicle Air Conditioners (MVAC).
40 CFR 82: Subpart F: Recycling and Emissions Reduction.

State: ***(description)***

CHAPTER 62-4, F.A.C.: PERMITS, effective 10-16-95

62-4.030, F.A.C.: General Prohibition.
62-4.040, F.A.C.: Exemptions.
62-4.050, F.A.C.: Procedure to Obtain Permits; Application
62-4.060, F.A.C.: Consultation.
62-4.070, F.A.C.: Standards for Issuing or Denying Permits; Issuance; Denial.
62-4.080, F.A.C.: Modification of Permit Conditions.
62-4.090, F.A.C.: Renewals.
62-4.100, F.A.C.: Suspension and Revocation.
62-4.110, F.A.C.: Financial Responsibility.
62-4.120, F.A.C.: Transfer of Permits.
62-4.130, F.A.C.: Plant Operation - Problems.
62-4.150, F.A.C.: Review
62-4.160, F.A.C.: Permit Conditions.
62-4.210, F.A.C.: Construction Permits.
62-4.220, F.A.C.: Operation Permit for New Sources.

CHAPTER 62-103, F.A.C.: RULES OF ADMINISTRATIVE PROCEDURE, effective 12-31-95

62-103.150, F.A.C.: Public Notice of Application and Proposed Agency Action.
62-103.155, F.A.C.: Petition for Administrative Hearing; Waiver of Right to Administrative Proceeding

CHAPTER 62-210, F.A.C.: STATIONARY SOURCES - GENERAL REQUIREMENTS, effective 03-21-96

62-210.300, F.A.C.: Permits Required.
62-210.300(1), F.A.C.: Air Construction Permits.
62-210.300(2), F.A.C.: Air Operation Permits.
62-210.300(3), F.A.C.: Exemptions.
62-210.300(3)(a), F.A.C.: Full Exemptions.
62-210.300(3)(b), F.A.C.: Temporary Exemption.

62-210.300(5), F.A.C.: Notification of Startup.
62-210.300(6), F.A.C.: Emissions Unit Reclassification.

62-210.350, F.A.C.: Public Notice and Comment.
62-210.350(3), F.A.C.: Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources.

62-210.360, F.A.C.: Administrative Permit Corrections.

62-210.370(3), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility.

62-210.650, F.A.C.: Circumvention.

62-210.900, F.A.C.: Forms and Instructions.
62-210.900(1) Application for Air Permit - Long Form, Form and Instructions.
62-210.900(5) Annual Operating Report for Air Pollutant Emitting Facility, Form and Instructions.

CHAPTER 62-213, F.A.C.: OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION, effective 03-20-96

62-213.205, F.A.C.: Annual Emissions Fee.
62-213.400, F.A.C.: Permits and Permit Revisions Required.
62-213.410, F.A.C.: Changes Without Permit Revision.
62-213.412, F.A.C.: Immediate Implementation Pending Revision Process.
62-213.420, F.A.C.: Permit Applications.
62-213.430, F.A.C.: Permit Issuance, Renewal, and Revision.
62-213.440, F.A.C.: Permit Content.
62-213.460, F.A.C.: Permit Shield.

62-213.900, F.A.C.: Forms and Instructions.
62-213.900(1) Major Air Pollution Source Annual Emissions Fee Form, Form and Instructions.

CHAPTER 62-256, F.A.C.: OPEN BURNING AND FROST PROTECTION FIRES, effective 11-30-94

CHAPTER 62-257, F.A.C: ASBESTOS NOTIFICATION AND FEE, effective 03/24/96

CHAPTER 62-281, F.A.C: MOTOR VEHICLE AIR CONDITIONING REFRIGERANT RECOVERY AND RECYCLING, effective 03-07-96

CHAPTER 62-296, F.A.C.: STATIONARY SOURCES - EMISSION STANDARDS, effective 03-13-96

62-296.320(2), F.A.C.: Objectionable Odor Prohibited.
62-296.320(3), F.A.C.: Industrial, Commercial, and Municipal Open Burning Prohibited
62-296.320(4)(c), F.A.C.: Unconfined Emissions of Particulate Matter

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
PM	**A**				**Particulate Matter – Total**
PM_{10}	**A**				**Particulate Matter – PM_{10}**
SO_2	**A**				**Sulfur Dioxide**
NO_X	**A**				**Nitrogen Oxides**
CO	**A**				**Carbon Monoxide**
VOC	**A**				**Volatile Organic Compounds**
PB	**B**				**Lead**
H114	**B**				**Mercury**
H021	**B**				**Beryllium Compounds**
FL	**B**				**Fluorides - Total**
SAM	**B**				**Sulfuric Acid Mist**
HAPs	**A**				**Hazardous Air Pollutants See Att. OC-AI-AD**

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID:________ [X] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [X] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID:__________ [X] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [X] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:_________[X] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:____________________________) [X] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:________ [X] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________ [X] Not Applicable

ATTACHMENT OC-AI-AC

APPLICATION COMMENT

ATTACHMENT OC-AI-AC
APPLICATION COMMENT

The contact shown is for the Okeelanta Corporation sugar mill and refinery. The application contact for Okeelanta Power L.P. cogeneration facility is:

James Meriwether, Env. Health & Safety Rep.
Okeelanta Power L.P.
P.O. Box 9
8001 U.S. Highway 27 South
South Bay, FL, 33493
Phone: (561) 993-1003
Fax: (561) 996-6596

APPLICATION OC-AI-AD

FACILITY POLLUTANTS COMMENT

ATTACHMENT OC-AI-AD
FACILITY POLLUTANTS COMMENT

At this time, it is unclear whether Okeelanta Corporation or Okeelanta Power L.P. should be classified as major for HAPs. Okeelanta Power L.P. has no emissions test data indicating significant HAP emissions from its boilers. Emissions test data from the Pulp and Paper Industry indicate HAPs emissions from wood-fired boilers. However, these emissions data may not be representative of Okeelanta Power HAP emissions. In addition, recent sugar industry test data indicate HAPs emissions from sugar industry bagasse fired boilers. However, these emissions data may not be representative of Okeelanta Corporation HAP emissions. Okeelanta is currently not operating its sugar mill boilers, as steam is being supplied by Okeelanta Power.

Okeelanta Power has emission limits for the HAPs lead, mercury, and beryllium, and has limited actual test data for these HAPs as well as chromium and arsenic. These limits and test data show Okeelanta Power to be well below the major source threshold for HAPs. Okeelanta Corporation has no emissions test data related to HAP emissions from its boilers, which are now shutdown. As a result, Okeelanta Corporation/Okeelanta Power cannot determine if the facility is major for individual HAPs or for total HAPs, nor if HAPs emissions from any individual emissions unit exceeds a reporting threshold.

APPLICATION OC-FI-A7

FACILITY COMMENT

ATTACHMENT OC-FI-A7
FACILITY COMMENT

This facility consists of two operating units: the Okeelanta Corporation (OC) Sugar Mill, Refinery, Packaging and Transhipment operations; and the Okeelanta Power Limited Partnership (OPLP) cogeneration facility.

OKEELANTA CORPORATION SUGAR MILL

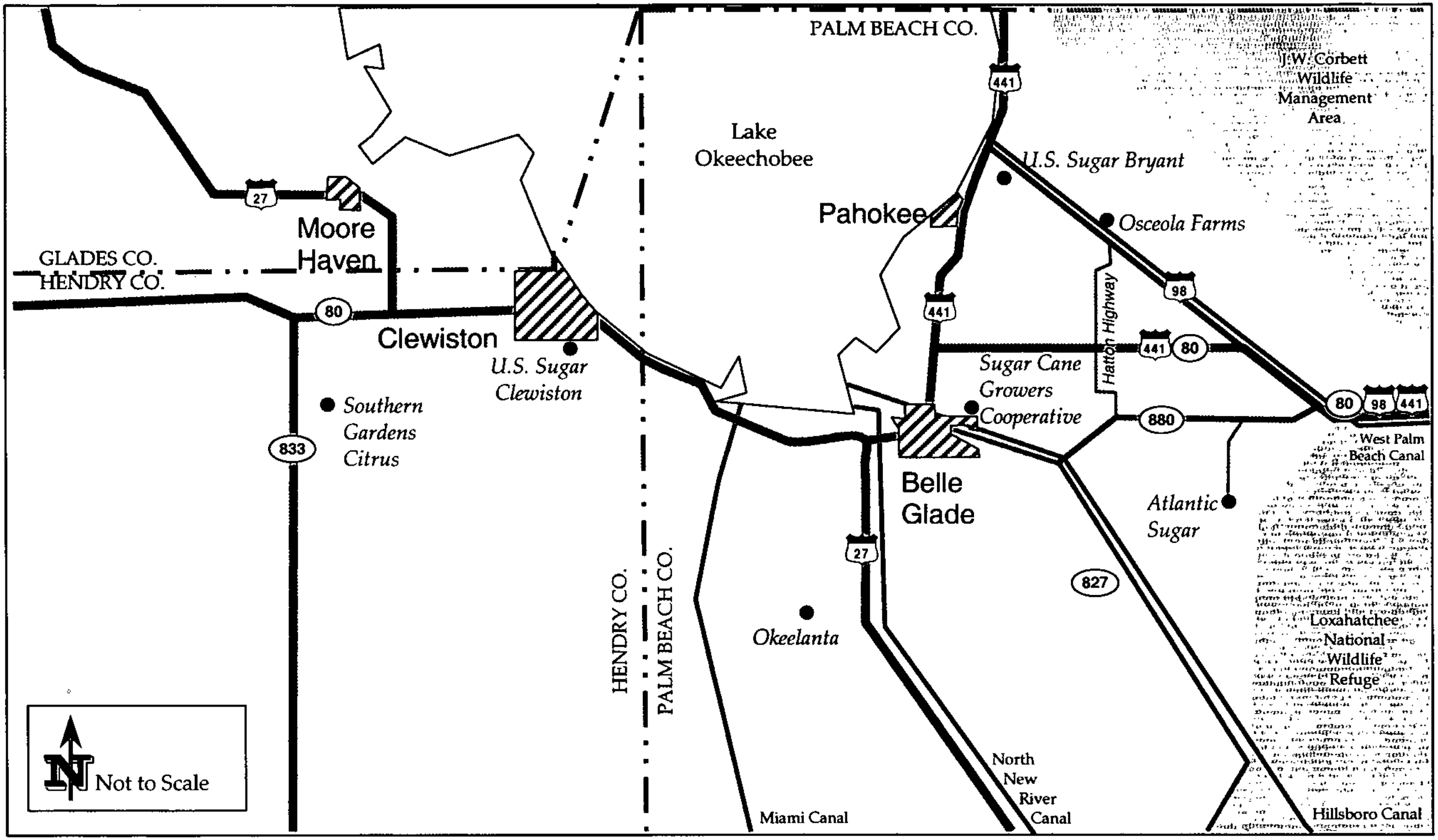
The OC Sugar Mill consists of all operations necessary to manufacture raw sugar from sugar cane. In reference to the OC Sugar Mill facility flow diagram (Attachment OC-FE-3), based on historical agricultural crop seasons, approximately 27,000 tons of cane can be processed per day. This operating rate will vary from season to season depending on agricultural, market, and weather conditions. The Refinery and Transhipment operations are permitted to operate 8,760 hr/year.

OKEELANTA POWER L.P. COGEN FACILITY

The OPLP cogeneration facility consists of three boilers and all operations necessary to generate steam for the OC sugar mill and refinery, as well as generate electricity for sale to the grid.

ATTACHMENT OC-FI-C1

AREA MAP SHOWING FACILITY LOCATION



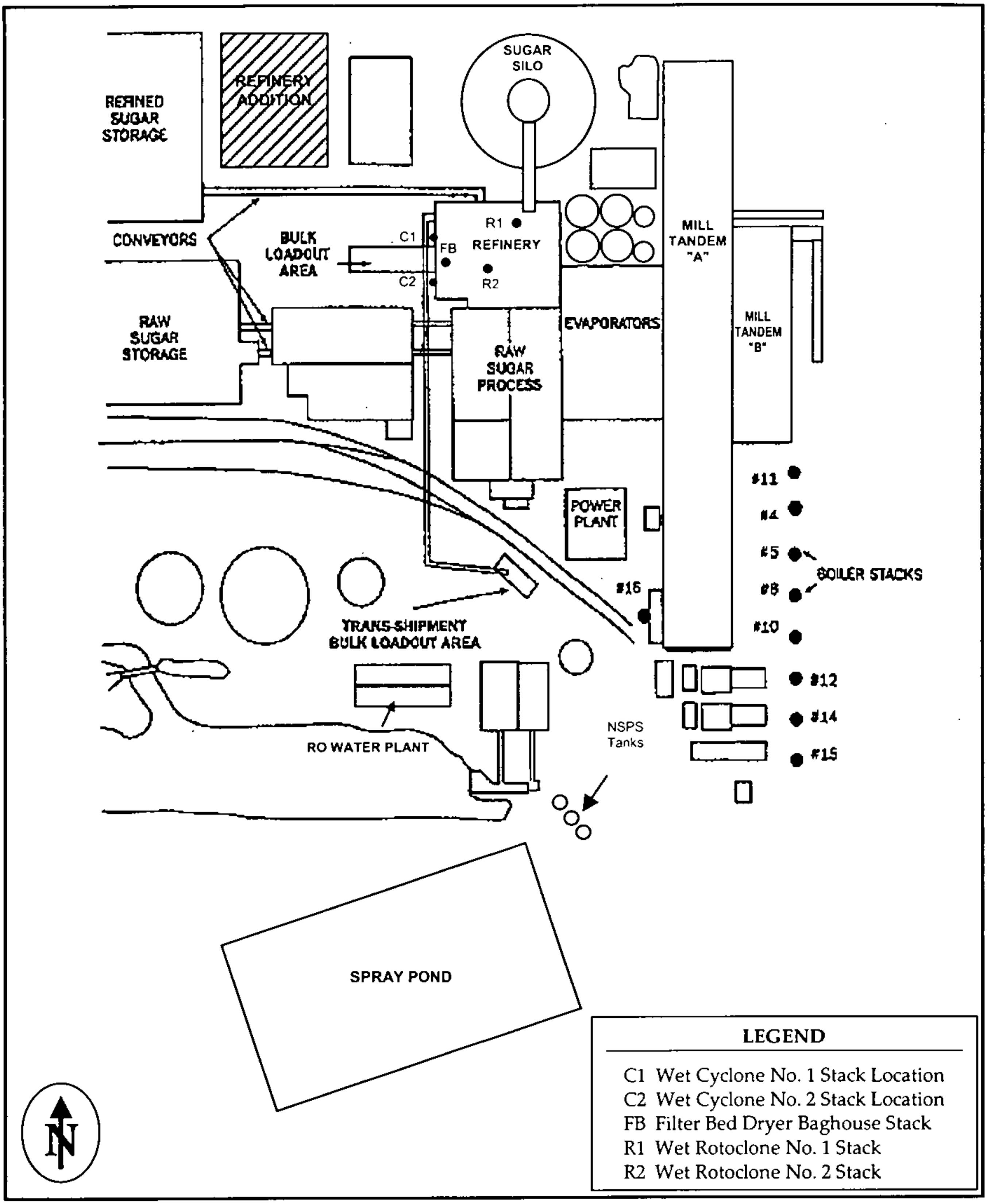
Attachment OC-FI-C1
Location of Okeelanta Corporation

Source: Golder Associates Inc., 2000.

Golder Associates

ATTACHMENT OC-FI-C2

FACILITY PLOT PLAN



Attachment OC-FI-C2

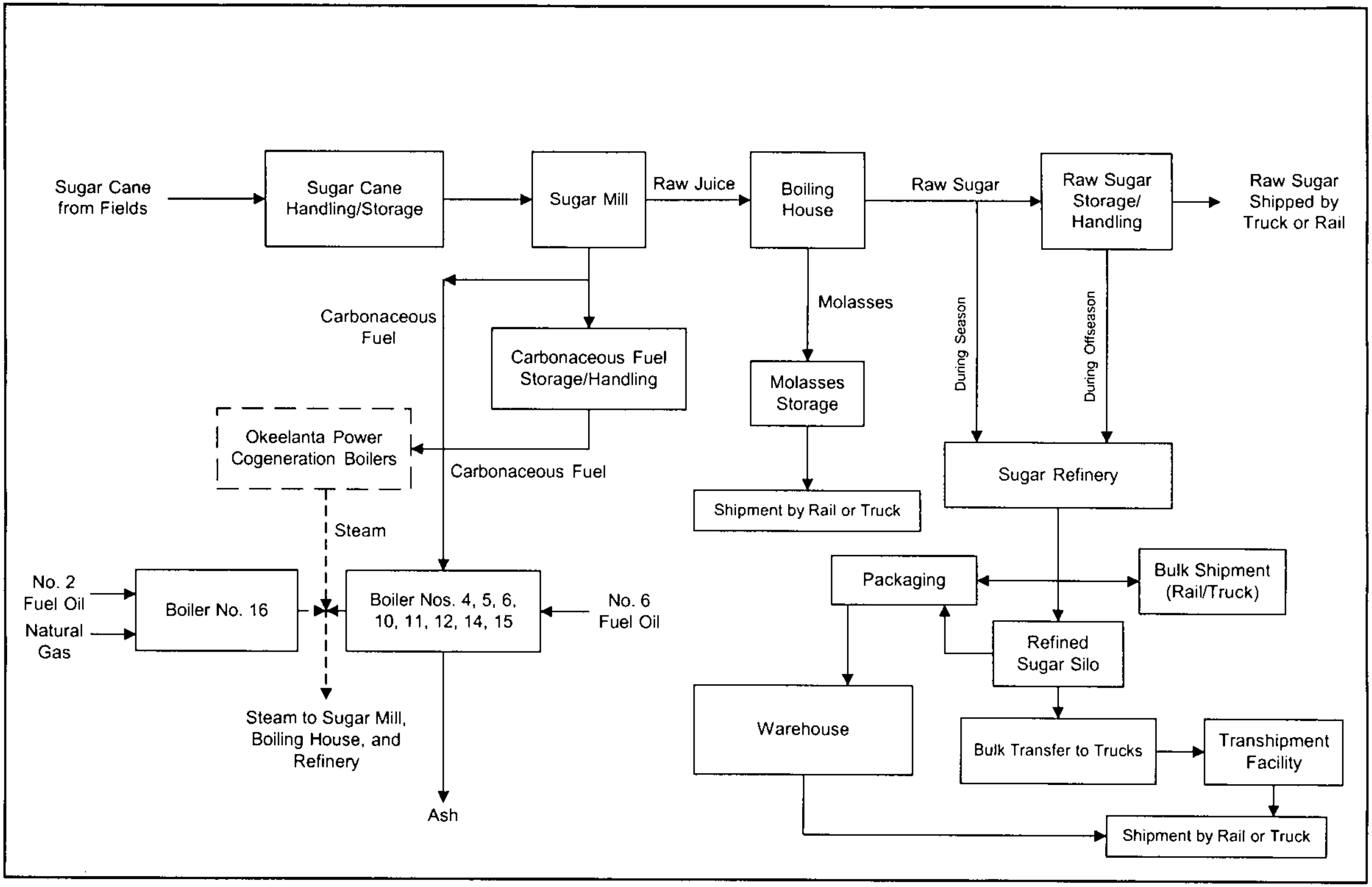
Facility Plot Plan of Okeelanta Sugar Mill and Refinery

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

Golder Associates

ATTACHMENT OC-FI-C3

PROCESS FLOW DIAGRAM



Attachment OC-FI-C3a
Sugar Manufacturing
Process Flow Diagram
Okeelanta Corporation
South Bay, FL

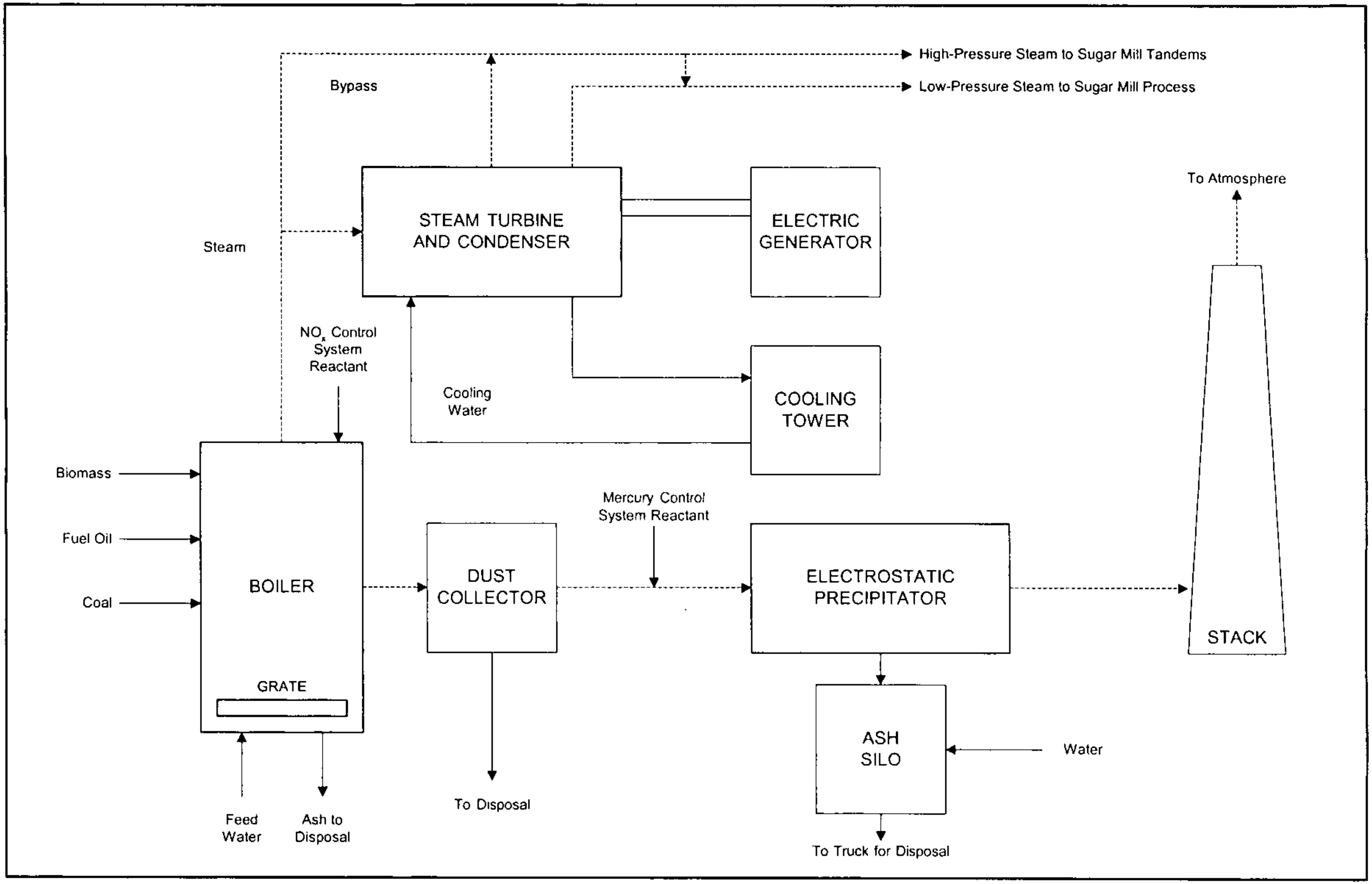
Process Flow Legend
Solid/Liquid →
Steam - - - →

Overall Sugar Mill - Facility Flow Diagram

Filename: 0037593Y\F1\WP\OC-FI-C3.VSD (A)

Date: 03/12/01

Golder Associates



Attachment OC-FI-3b
Simplified Flow Diagram
Okeelanta Power Cogeneration Facility
South Bay, FL

Process Flow Legend
Solid/Liquid ⟶
Steam - - - ->

Filename: 0037593Y\F1\WP\OC-FI-C3.VSD (B)
Date: 03/12/01

Golder Associates

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

[X] 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. Regulated or Unregulated Emissions Unit? (Check one)

[X] 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Mill Boiler No. 16

4. Emissions Unit Identification Number: [ ] No ID
ID: **014** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A		**20**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Package Boiler equipped with Lo-NO_x burners for No. 2 distillate fuel oil and natural gas. This unit is designed for 40% flue gas recirculation.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Lo-NO_x Burners**	
2. Control Device or Method Code(s): **024**	

Emissions Unit Details

1. Package Unit: Manufacturer: **Babcock and Wilcox**	Model Number: **FM 120-97**	
2. Generator Nameplate Rating:	MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		°F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		211	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			tons/hr
4. Maximum Production Rate:		150,000	
5. Requested Maximum Operating Schedule:			
	24 hours/day	7	days/week
	5 weeks/year	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60.11 General NSPS Requirement	40 CFR 60.44b(i) 40 CFR 60 Subpart Db
40 CFR 60.12 General NSPS Requirement	40 CFR 60.45b(j) 40 CFR 60 Subpart Db
40 CFR 60.13(a) General NSPS Requirement	40 CFR 60.46b(a) 40 CFR 60 Subpart Db
40 CFR 60.13(b) General NSPS Requirement	40 CFR 60.46b(c) 40 CFR 60 Subpart Db
40 CFR 60.13(c) General NSPS Requirement	40 CFR 60.46b(d)(7) 40 CFR 60 Subpart Db
40 CFR 60.13(d) General NSPS Requirement	40 CFR 60.46b(e)(1) 40 CFR 60 Subpart Db
40 CFR 60.13(e) General NSPS Requirement	40 CFR 60.46b(e)(4) 40 CFR 60 Subpart Db
40 CFR 60.13(f) General NSPS Requirement	40 CFR 60.47b(f) 40 CFR 60 Subpart Db
40 CFR 60.13(h) General NSPS Requirement	40 CFR 60.48b(a) 40 CFR 60 Subpart Db
40 CFR 60.13(i) General NSPS Requirement	40 CFR 60.48b(b) 40 CFR 60 Subpart Db
40 CFR 60.13(j) General NSPS Requirement	40 CFR 60.48b(c) 40 CFR 60 Subpart Db
40 CFR 60.19 General NSPS Requirement	40 CFR 60.48b(d) 40 CFR 60 Subpart Db
40 CFR 60.42b(a) 40 CFR 60 Subpart Db	40 CFR 60.48b(e)(2) 40 CFR 60 Subpart Db
40 CFR 60.42b(g) 40 CFR 60 Subpart Db	40 CFR 60.48b(e)(3) 40 CFR 60 Subpart Db
40 CFR 60.42b(j) 40 CFR 60 Subpart Db	40 CFR 60.48b(f) 40 CFR 60 Subpart Db
40 CFR 60.43b(f) 40 CFR 60 Subpart Db	40 CFR 60.49b(a) 40 CFR 60 Subpart Db
40 CFR 60.43b(g) 40 CFR 60 Subpart Db	40 CFR 60.49b(b) 40 CFR 60 Subpart Db
40 CFR 60.44b(a)(1)(ii) 40 CFR 60 Subpart Db	40 CFR 60.49b(d) 40 CFR 60 Subpart Db
40 CFR 60.44b(h) 40 CFR 60 Subpart Db	40 CFR 60.49b(f) 40 CFR 60 Subpart Db

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations (continued)

40 CFR 60.49b(g) 40 CFR 60 Subpart Db	
40 CFR 60.49b(h) 40 CFR 60 Subpart Db	
40 CFR 60.49b(i) 40 CFR 60 Subpart Db	
40 CFR 60.49b(o) 40 CFR 60 Subpart Db	
40 CFR 60.49b(r) 40 CFR 60 Subpart Db	
40 CFR 60.7 General NSPS Requirements	
40 CFR 60.8 General NSPS Requirements	
62-212.400(2) Stationary Sources - Preconstruction Review Requirements	
62-212.400(5) Preconstruction Review Requirements	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

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 (limit to 100 characters per point):		
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: **410** °F	9. Actual Volumetric Flow Rate: **88,200** acfm	10. Water Vapor: %
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 Comment (limit to 200 characters): **Stack parameters are based on stack test data.**		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

   Industrial Boiler - Distillate Oil, Grades 1 and 2 Oil

2. Source Classification Code (SCC): **1-02-005-01**		3. SCC Units: **Thousand Gallons Burned (all liquid fuels)**
4. Maximum Hourly Rate: **1.485**	5. Maximum Annual Rate: **10,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **136**

10. Segment Comment (limit to 200 characters):

    Based on 202 MMBtu/hr while firing No. 2 fuel oil. Maximum Annual Rate based on cap of 10,000,000 gallons per year.

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

   Industrial Boiler, natural gas greater than 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: **1812.12**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,020**

10. Segment Comment (limit to 200 characters):

    Based on 211 MMBtu/hr while firing natural gas.

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
PM_{10}			EL
SO_2			EL
NO_x			EL
CO			EL
VOC			EL
SAM			NS
Pb			NS
H114			NS
H021			NS

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **6.46** lb/hour **22.16** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.032 lb/MMBtu** Reference: **Emission test results**	7. Emissions Method Code: **1**
8. Calculation of Emissions (limit to 600 characters): **See Table 2-1 for calculations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Maximum annual emissions based on firing both natural gas and fuel oil. Emission factor given is based on emission tests while firing fuel oil.**	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **6.46** lb/hour **22.16** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.032 lb/MMBtu** Reference: **Emission test results**	7. Emissions Method Code: **1**
8. Calculation of Emissions (limit to 600 characters): **See Table 2-1 for calculations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Assumed PM_{10} is 100 percent of PM.**	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.66** lb/hour **39.38** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.058 lb/MMBtu** Reference: **AP-42, Table 1.3-1**	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **See Table 2-1 for calculations**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Maximum annual emissions based on firing both natural gas and maximum No. 2 fuel oil. Limited No. 2 fuel oil usage to 10,000,000 gallons per year. Emission factor given is for fuel oil firing.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05% S**	4. Equivalent Allowable Emissions: **11.66** lb/hour **39.38** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Analysis**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Limit is maximum sulfur content of No. 2 fuel oil.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **30.30** lb/hour **113.78** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.15 lb/MMBtu** Reference: **Manufacturer's guarantee**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Table 2-1 for calculations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission factor based on fuel oil firing.**	

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.15 lb/MMBtu**	4. Equivalent Allowable Emissions: **30.30** lb/hour **102.02** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 7, 7A, or 7E**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on manufacturer's guarantee for fuel oil firing.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.055 lb/MMBtu**	4. Equivalent Allowable Emissions: **11.61** lb/hour **50.83** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 7, 7A, or 7E**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on manufacturer's guarantee for natural gas firing.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **32.32** lb/hour **140.90** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.16 lb/MMBtu** Reference: **Manufacturer's Estimate**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Table 2-1 for calculations**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission factor based on fuel oil-firing.**	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **6.33** lb/hour **27.73** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.03 lb/MMBtu** Reference: **Manufacturer's Guarantee**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Table 2-1 for calculations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on natural gas firing.**	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.52** lb/hour **1.75** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.0026 lb/MMBtu** Reference: **See Comment**	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **See Table 2-1 for calculations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission factor based on the factor for SO_3 from fuel oil in AP-42, Section 1.3, then take into account the ratio of sulfuric acid mist and gaseous sulfate molecular weights (98/80).**	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0018** lb/hour **0.0062** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **9.00 x 10^{-6} lb/MMBtu** Reference: **AP-42, Table 1.3-10 (9/98)**	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **See Table 2-1 for calculations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on fuel oil and natural firing. Emission factor given is for fuel oil.**	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **H114**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **0.00061** lb/hour **0.0021** tons/year

4. Synthetically Limited? [ ]

5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor: **3 x 10^{-6} lb/MMBtu**

   Reference: **AP-42, Table 1.3-10 (9/98)**

7. Emissions Method Code: **3**

8. Calculation of Emissions (limit to 600 characters):

   See Table 2-1 for calculations.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Based on fuel oil and natural gas firing. Emission factor given is for fuel oil firing.

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lb/hour tons/year

5. Method of Compliance (limit to 60 characters):

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **H021**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.00061** lb/hour **0.0020** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **3 x 10^{-6} lb/MMBtu** Reference: **AP-42, Table 1.3-10 (9/98)**	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **See Table 2-1 for calculations**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on fuel oil firing. Fuel oil usage limited to 10,000,000 gallons per year.**	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **0** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **40 CFR 60 Subpart Db 60.43b**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 5

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Rosemount** Model Number: **OPM2000**	Serial Number: **See Comment**
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60 Subpart Db 60.42b(a). No serial number or installation date provided because monitor is routinely replaced to ensure optimum performance.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Rosemount** Model Number: **NGA2000**	Serial Number: **See Comment**
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60 Subpart Db 60.48b(b). No serial number or installation date provided because monitor is routinely replaced to ensure optimum performance.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 3 of 5

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: **Honeywell** Model Number: **DR4500 Truline**	Serial Number: **See Comment**
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **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. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 4 of 5

1. Parameter Code: TEMP	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: Honeywell Model Number: DR4500 Truline	Serial Number: See Comment
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): Existing permit condition required monitoring of the steam temperature. No serial number or installation date provided because meter is routinely replaced to ensure optimum performance.	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 5 of 5

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: **Honeywell** Model Number: **DR4500 Truline**	Serial Number: **See Comment**
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Existing permit condition requires monitoring of steam pressure. No serial number or installation date provided because meter is routinely replaced to ensure optimum performance.**	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1.	Process Flow Diagram [X] Attached, Document ID: OC-EU1-J1 [ ] Not Applicable [ ] Waiver Requested
2.	Fuel Analysis or Specification [ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
3.	Detailed Description of Control Equipment [ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
4.	Description of Stack Sampling Facilities [ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
5.	Compliance Test Report [ ] Attached, Document ID: ______ [ ] Previously submitted, Date: ______ [X] Not Applicable
6.	Procedures for Startup and Shutdown [ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
7.	Operation and Maintenance Plan [ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
8.	Supplemental Information for Construction Permit Application [X] Attached, Document ID: See PSD Report [ ] Not Applicable
9.	Other Information Required by Rule or Statute [ ] Attached, Document ID: ______ [X] Not Applicable
10.	Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [X] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [X] Not Applicable

13. Identification of Additional Applicable Requirements
    [X] Attached, Document ID: OC-EU1-J13 [ ] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [X] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID:________

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID:________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID:________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

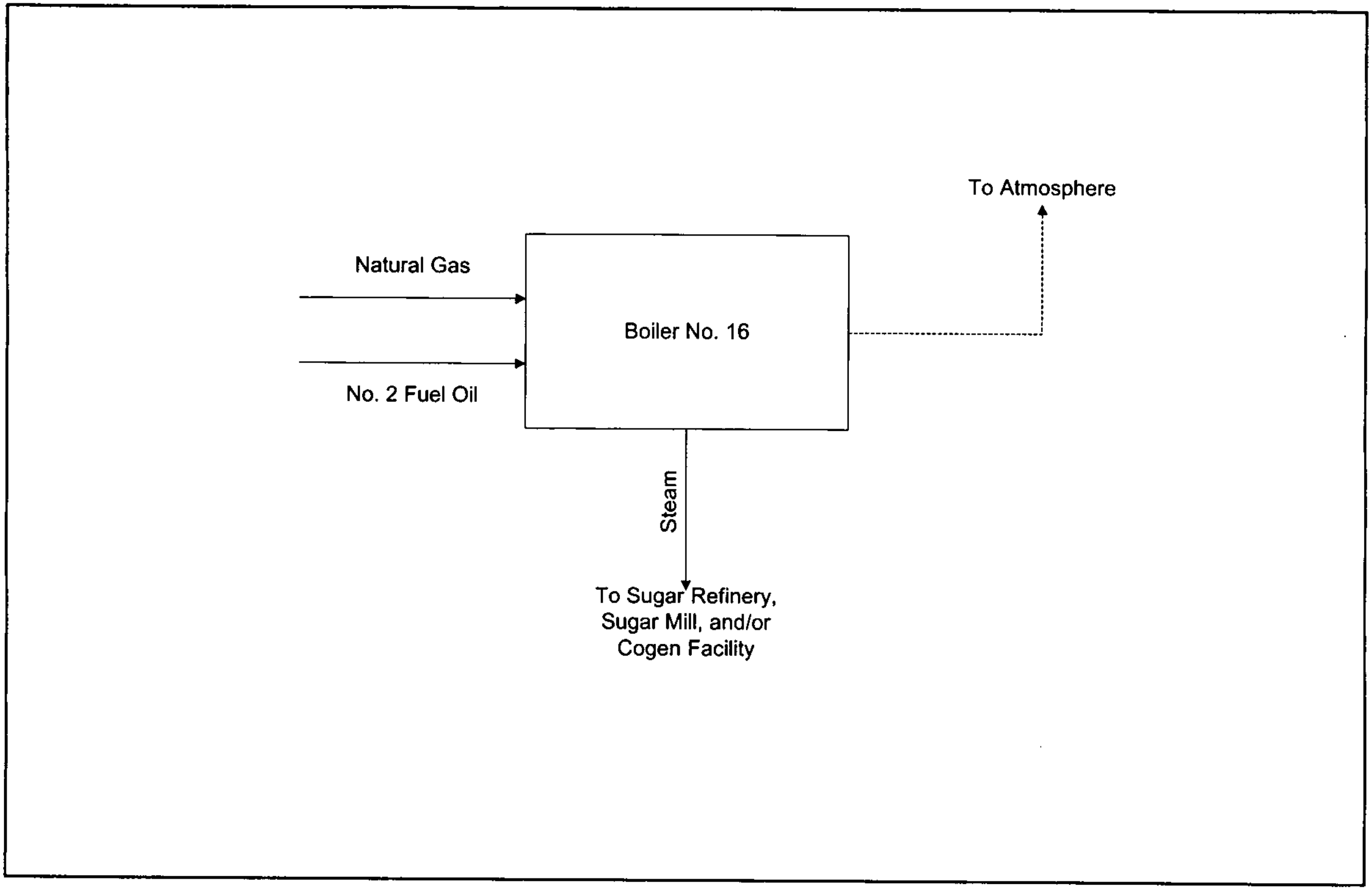
    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [X] Not Applicable

ATTACHMENT OC-EU1-J1

PROCESS FLOW DIAGRAM

0037593Y\F1\WP\



Attachment OC-EU1-J1 Boiler No. 16 Process Flow Diagram Okeelanta Corporation South Bay, FL	**Process Flow Legend** Solid/Liquid Gas Steam	Boiler No. 16 Filename: OC-EU1-J1.VSD Date: 03/12/01	Golder Associates

ATTACHMENT OC-EU1-J13

IDENTIFICATION OF ADDITIONAL APPLICABLE REQUIREMENTS

AIR CONSTRUCTION PERMIT

FLORIDA

Department of
Environmental Protection

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

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

I.D. No: 52FTM50000514
Permit/Certification
Number: AO50-257065
Date of Issue: November 29, 1994
Expiration Date: November 29, 1999
County: Palm Beach
Latitude: 26° 35′ 00″ N
Longitude: 80° 45′ 00″ W
Section/Town/Range: 16/45S/36E
Project: Boiler No. 16

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Rules 62-4, 62-296, and 62-297. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the Department and made a part hereof and specifically described as follows:

Operation of a 150,000 lbs steam/hr, No. 2 oil fired, 205 MMBtu/hr heat input Babcock & Wilcox Model FM 120-97 package boiler using Coen's LO-NO_X burners and designed for 40% flue gas recirculation.

The boiler is located at the permittee's existing sugar mill that is approximately 6 miles south of South Bay, Palm Beach County, Florida, off of U.S. Highway 27.

Pertinent Documents		Dated
BACT		
PSD	PSD-FL-169	
NSPS	40 CFR Part 60 Subpart Db	
Construction Permit AC50-191876		29 July 1991
Revision of AC50-191876		18 Feb. 1993
DEP Form 62-1.202(3) CoCoC		31 Aug. 1994

Title V Permit
SIC Number 2061
SCC Numbers 1-02-005-01

PERMITTEE:
Okeelanta Corporation

I.D. No.: 52FTM50000514
Permit/Cert. No.: AO50-257065
Date of Issue: November 29, 1994
Expiration Date: November 29, 1999

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5) Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by any order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

PERMITTEE:
Okeelanta Corporation

I.D. No.: 52FTM50000514
Permit/Cert. No.: AO50-257065
Date of Issue: November 29, 1994
Expiration Date: November 29, 1999

GENERAL CONDITIONS:

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law, and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any records that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a. a description of and cause of non-compliance; and

b. the period of non-compliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source, which are submitted to the Department, may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Section 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

PERMITTEE:
Okeelanta Corporation

I.D. No.: 52FTM50000514
Permit/Cert. No.: AO50-257065
Date of Issue: November 29, 1994
Expiration Date: November 29, 1999

GENERAL CONDITIONS:

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-30.300, F.A.C. as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

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

14. The permittee shall comply with the following:

(a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically, unless otherwise stipulated by the Department.

(b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report or application unless otherwise specified by Department rule.

(c) Records of monitoring information shall include:

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

PERMITTEE:
Okeelanta Corporation

I.D. No.: 52FTM50000514
Permit/Cert. No.: AO50-257065
Date of Issue: November 29, 1994
Expiration Date: November 29, 1999

GENERAL CONDITIONS:

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware the relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

FACILITY OPERATIONS:

1. All fugitive dust generated at this site shall be adequately controlled. [Reference Rule 62-296.310(3), F.A.C.]

2. This facility shall be operated in such a fashion so as to preclude objectionable odors. [Reference Rule 62-296.320(2), F.A.C.]

3. There shall be no discharges of liquid effluents or contaminated runoff from the plant site.

CONDITIONS OF COMPLIANCE:

4. Stack sampling facilities provided by the owner shall be in accordance with the requirements of Chapter 62-297.345, F.A.C.

5. The boiler shall be equipped with instruments to measure the opacity of the stack emissions and the steam production, temperature, and pressure.

6. Air pollutant emissions shall not exceed any of the quantities listed below:

Pollutant	lbs/MMBtu	Emissions lbs/hr	Emissions TPY**	Compliance Test Method EPA Test Methods (July 1, 1990)
PM	0.054	11.0	23.1	5
Pm10	0.027	5.5	11.6	201 or 201A
SO_2	0.51	105.5	132.9	Certified Fuel Analysis
NO_x	0.18*	36.9	77.5	7, 7A, 7E
CO	0.20	41.0	86.1	10
VOC	0.09	18.5	38.7	25
VE	20% opacity (6-minute average) except 27% (max.) for 1 6-minute period/hr.			9

* 30-day rolling average as determined from the NO_x monitor data.
** Emissions during the period from March 1 to October 31.

PERMITTEE:
Okeelanta Corporation

I.D. No.: 52FTM50000514
Permit/Cert. No.: AO50-257065
Date of Issue: November 29, 1994
Expiration Date: November 29, 1999

SPECIFIC CONDITIONS:

CONDITIONS OF COMPLIANCE:

7. Boiler No. 16 shall comply with all applicable requirements of 40 CFR 60, including Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Unit (December 18, 1989).

40 CFR 60.7, Notification and record keeping. Timely notification of the items listed to the Department (South District), Palm Beach County Public Health Unit (PBCPHU), and EPA.

40 CFR 60.42b, Standard for sulfur dioxide. Sulfur content of the No. 2 distillation oil fuel shall not exceed 0.5%. Annual off-season average shall not exceed 0.3% sulfur. The Permittee shall maintain fuel analysis or receipts to confirm compliance with this condition.

40 CFR 60.43b, Standard for particulate matter. Visible emissions shall not exceed 20% opacity (6-minute average), except for one 6-minute period per hour of not more than 27% opacity.

40 CFR 60.44b, Standard for nitrogen oxides for high heat release boiler No. 16, expressed as NO_2, is 0.20 lbs/MMBtu.

40 CFR 60.45b, Sulfur dioxide compliance tests, fuel receipts or analysis for sulfur content is required to confirm compliance with this condition.

40 CFR 60.46b, Particulate and nitrogen oxides compliance tests. Method 9 test required to determine compliance with the opacity standard. Method 7, 7A, or 7E test for nitrogen oxides.

40 CFR 60.47b, Sulfur dioxide monitoring. Fuel analysis or receipts required to confirm compliance with this condition.

40 CFR 60.48b, Particulate and nitrogen oxides monitoring. Continuous emissions monitor required to measure opacity.

40 CFR 60.49b, Reporting and record keeping requirements. Permittee required to report date of initial start up. design heat input capacity, fuels used, annual capacity factor, performance test data, plan to monitor NO_x, nitrogen content of the distillate oil, opacity, nitrogen dioxide emissions, monitor down time, "F" factor, exceedances, and other information required by this paragraph.

8. Only No. 2 fuel oil containing a maximum of 0.5% sulfur (off-season average of 0.3% sulfur) shall be used as fuel.

PERMITTEE:
Okeelanta Corporation

I.D. No.: 52FTM50000514
Permit/Cert. No.: AO50-257065
Date of Issue: November 29, 1994
Expiration Date: November 29, 1999

SPECIFIC CONDITIONS:

CONDITIONS OF COMPLIANCE:

9. Maximum heat input to the boiler shall not exceed 1,463 gallons per hour of No. 2 distillate fuel oil (205 MMBtu/hr).

10. The boiler shall not operate more than 175 days (4,200 hours) during the off-season months of March through October. During the crop season (November through February), the heat input to boiler No. 16 is limited to the equivalent reduction in heat input from No. 6 fuel oil for the existing bagasse/No. 6 fuel oil fired boilers at this facility. It is not to be operated as a replacement to a functional bagasse fired boiler when bagasse fuel is available. Total oil consumption (fuel oils No. 2 and No. 6) by all boilers at this facility (boilers Nos. 4,5,6,10,11,12,14,15, and 16) shall not exceed 3.2 million gallons during the crop season (November through February) and total maximum steam production shall not exceed 1.012 million pounds per hour.

Nov 30
Dec 31
Jan 31
Feb 28
121 =
175
296
x 24
7104

11. Steam production shall not exceed 150,000 lbs/hr.

REQUIRED TESTING:

12. Various emission tests are required to show continuing compliance with the standards of the Department. The test results must provide reasonable assurance that the unit is capable of compliance at the permitted maximum operating rate. Test shall be conducted in accordance with the EPA Methods specified in Specific Condition 6 and as published in 40 CFR-60, Appendix A, or State approved equivalent method. Such tests shall be conducted once per year within 60 days prior to August 4th. Results shall be submitted to the Department within 45 days after testing. The Department shall be notified at least 15 days prior to testing to allow witnessing.

13. Particulate matter, visible emissions, and nitrogen oxides emissions tests shall be conducted annually while the boiler is operating between 90-100% of its permitted capacity (135-150,000 lbs steam/hr). The volume and sulfur content of each fuel oil delivery shall be kept in a log for a minimum of 3 years. The continuous emissions monitoring data will be evaluated to determine the highest concentration of NO_x in lbs/MMBtu for any 30-day rolling average during the proceeding year. Tests for other pollutants may be required when the Department has good reason to believe the emission standard is being exceeded.

REPORTS AND RECORDKEEPING:

14. The permittee shall maintain a log that shows the boiler's operation time, steam production, and fuel consumption.

PERMITTEE:
Okeelanta Corporation

I.D. No.: 52FTM50000514
Permit/Cert. No.: AO50-257065
Date of Issue: November 29, 1994
Expiration Date: November 29, 1999

SPECIFIC CONDITIONS:

REPORTS AND RECORDKEEPING:

15. Stack test results shall be submitted to the Department and the PBCPHU within 45 days of the test.

16. An annual operation report (DER Form 62-210.900(4) attached) shall be submitted by March 1st each year. The attached form shall be reproduced by the permittee and used for future annual submittals.[Reference Rule 62-4.070(3), and Rule 62-210.370(2), F.A.C.]

NOTE: In the event of an emergency the permittee shall contact the Department by calling (904) 413-9911 for "call back immediately", or (904) 413-9912 for "call back quickly, but not necessarily immediately". During normal business hours, the permittee shall call (813) 332-6975.

Issued this 29th day of November, 1993.

STATE OF FLORIDA
DEPARTMENT OF
ENVIRONMENTAL PROTECTION

PJWare

Peter J. Ware
Director of
District Management

PJW/AEL/jw

11 Pages Attached

AIR OPERATING PERMIT

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Virginia B. Wetherell, Secretary

February 18, 1993

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Pablo A. Carreno
Director of Mill & Refinery Operation
Okeelanta Corporation
Post Office Box 86
South Bay, Florida 33493

Dear Mr. Carreno:

Re: Revision to Construction Permit No. AC50-191876 (PSD-FL-169)

The Department is in receipt of your request and supporting data to operate No. 2 fuel oil fired boiler No. 16 during the sugar cane crop season (November through February) in lieu of firing No. 6 fuel oil in the other boilers at the Okeelanta Corporation mill which is located in Palm Beach County, 6 miles south of South Bay. This request is acceptable, with conditions, and the referenced permit is amended:

FROM

Specific Condition No. 5:

Air pollutant emissions shall not exceed any of the quantities listed below:

Pollutant	lbs/MMBtu	Emissions lbs/hr	TPY	Compliance Test Method EPA Test Methods (July 1, 1990)
PM	0.054	11.0	23.1	5
PM_{10}	0.027	5.5	11.6	201 or 201A
SO_2	0.51	105.5	132.9	Certified Fuel Analysis
NOx	0.18*	36.9	77.5	7, 7A, 7E
CO	0.20	41.0	86.1	10
VOC	0.09	18.5	38.7	25
VE	20% opacity (6-minute average) except 27% (max.) for 1 6-minute period/hr.			9

* 30-day rolling average as determined from the NO_X monitor data.

Recycled Paper
Printed with Soy Based Inks

Specific Condition No. 10:

The boiler shall not operate for more than 175 days (4,200 hours) during any 12 month period. The boiler shall only operate during the off-season months (March through October).

TO:

Specific Condition No. 5:

Air pollutant emissions shall not exceed any of the quantities listed below:

Pollutant	lbs/MMBtu	Emissions lbs/hr	Emissions TPY**	Compliance Test Method EPA Test Methods (July 1, 1990)
PM	0.054	11.0	23.1	5
PM_{10}	0.027	5.5	11.6	201 or 201A
SO_2	0.51	105.5	132.9	Certified Fuel Analysis
NOx	0.18*	36.9	77.5	7, 7A, 7E
CO	0.20	41.0	86.1	10
VOC	0.09	18.5	38.7	25
VE	20% opacity (6-minute average) except 27% (max.) for 1 6-minute period/hr.			9

* 30-day rolling average as determined from the NO_x monitor data.

** Emissions during the period from March 1 to October 31.

Specific Condition No. 10:

The boiler shall not operate for more than 175 days (4,200 hours) during the off-season months (March through October). During the crop season (November through February), the heat input to boiler No. 16 is limited to the equivalent reduction in heat input from No. 6 fuel oil for the existing bagasse/No. 6 fuel oil fired boilers at this sugar mill. It shall not be operated as a replacement to a functional bagasse fired boiler when bagasse fuel is available. Total oil consumption (fuel oils No. 2 and No. 6) by all boilers at this facility (boilers Nos. 4, 5, 6, 10, 11, 12, 14, 15, and 16) shall not exceed 3.2×10^6 gallons during the crop season (November through February) and total maximum steam production shall not exceed 1,012,000 lbs/hr.

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

Sincerely,

Howard L. Rhodes

Howard L. Rhodes
Director
Division of Air Resources
Management

HLR/WH/plm

Attach: Okeelanta's September 25, 1992, letter
DER's October 15, 1992, letter
Okeelanta's November 13, 1992, letter
Okeelanta's January 25, 1993, letter

cc: David Knowles, SD
Stephanie Brooks, SED
Gregg Worley, EPA
Jim Stormer, PBC
David Buff, P.E.
Brian Mitchell, NPS

PERMIT # 16

Boiler # 16

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DER File No. AC 50-191876
Palm Beach County

Mr. Pablo A. Carreno
Director of Mill and Refinery Operations
Okeelanta Corporation
P. O. Box 86
South Bay, Florida 33493

Expires 3/1/93

Enclosed is Permit Number AC 50-191876 to construct an oil fired steam boiler (No. 16) at your sugar mill located on U.S. Highway 27, 6 miles south of South Bay, Palm Beach County, Florida, issued pursuant to Section(s) 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on 7-30-91 to the listed persons.

Clerk Stamp

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

Kim Dobes (Clerk) 7-30-91 (Date)

Copies furnished to:
David Knowles, South Dist.
Isidore Goldman SE Dist.
Jim Stormer, Palm Beach Co.
David Buff, P.E.
Jewell Harper, EPA
C. Shaver, NPS

Florida Department of Environmental Regulati

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-

Lawton Chiles, Governor

Carol M. Browner, Sec

PERMITTEE:

Okeelanta Corporation
P.O. Box 86
South Bay, Florida 33493

Permit Number: AC 50-191876
PSD-FL-169
Expiration Date: March 1, 1993
County: Palm Beach
Latitude/Longitude: 26035'00" N
80045'00" W
Project: Oil Fired Steam Boiler No. 16

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

Construction of a 150,000 lbs steam/hr, No. 2 oil fired, 205 MMBtu/hr heat input Babcock & Wilcox Model FM 120-97 package boiler using Coen's LO-NO_x burners and designed for 12% flue gas recirculation (or equivalent boiler with controls) equipped with a 5 ft. diameter by 75 ft. high stack. The boiler will be located at the permittee's existing sugar mill (SIC 2061) that is approximately 6 miles sought of South Bay, Palm Beach County, Florida off of U.S. Highway 27. The UTM coordinates of this site are Zone 17, 524.9 km E and 2940.1 km N.

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

Attachments are listed below:

1. Application received Jan. 29, 1991.
2. KBN letter dated Feb. 19, 1991.
3. BACT Determination.
4. KBN letter dated June 5, 1991.
5. Palm Beach County Health Unit letter dated June 5, 1991.
6. NPS letter dated July 1, 1991.
7. KBN letter dated July 9, 1991.

PERMITTEE:
Okeelanta Corporation

Permit Number: AC 50-191876
PSD-FL-169
Expiration Date: March 1, 1993

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to the public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve

PERMITTEE:
Okeelanta Corporation

Permit Number: AC 50-191876
PSD-FL-169
Expiration Date: March 1, 1993

GENERAL CONDITIONS:

compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any records that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend upon the nature of the concern being investigated.

8. If, for any reasons, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a. a description of and cause of non-compliance; and

b. the period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitting source arising under the Florida Statues or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida

GENERAL CONDITIONS:

Statues. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in the Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-30.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes Determination of Prevention of Significant Deterioration (PSD), Determination of Best Available Control Technology (BACT), and Compliance with New Source Performance Standards (NSPS).

14. The permittee shall comply with the following:

   a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulation by the Department.

   b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

GENERAL CONDITIONS:

c. Records of monitoring information shall include:

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

15. When request by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

Construction Details

1. The boiler shall be a flue gas recirculation type and equipped with low NO_x distillate oil burners. The design shall be for a heat release rate greater than 70,000 Btu/hr-ft^3.

2. The stack sampling facilities shall comply with F.A.C. Rule 17-2.700(4).

3. The 5 ft. diameter stack shall have a minimum height of 75 ft.

4. The boiler shall be equipped with instruments to measure the opacity of the stack emissions and the steam production, temperature, and pressure.

PERMITTEE:
Okeelanta Corporation

Permit Number: AC 50-191876
PSD-FL-169
Expiration Date: March 1, 1993

SPECIFIC CONDITIONS:

Emission Restrictions

5. Air pollutant emissions shall not exceed any of the quantities listed below:

Pollutant	lbs/MMBtu	Emissions lbs/hr	Emissions TPY	Compliance Test Method EPA Test Methods (July 1, 1990)
PM	0.054	11.0	23.1	5
PM10	0.027	5.5	11.6	201 or 201A
SO_2	0.51	105.5	132.9	Certified Fuel Analysis
NO_x	0.18*	36.9	77.5	7, 7A, 7E
CO	0.20	41.0	86.1	10
VOC	0.09	18.5	38.7	25
VE	20% opacity (6-minute average) except 27% (max.) for 1 6-minute period/hr.			9

* 30-day rolling average as determined from the NO_x monitor data.

Compliance Requirements

6. Particulate matter, visible emissions, and nitrogen oxides emissions tests shall be conducted annually while the boiler is operating between 90-100% of its permitted capacity (135-150,000 lbs steam/hr). The volume and sulfur content of each fuel oil delivery shall be kept in a log for a minimum of 3 years. The continuous emissions monitoring data will be evaluated to determine the highest concentration of NO_x in lbs/MMBtu for any 30-day rolling average during the proceeding year. Tests for other pollutants may be required when the Department has good reason to believe the emission standard is being exceeded.

Federal Requirements

7. Boiler No. 16 shall comply with all applicable requirements of 40 CFR 60, including Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Unit (December 18, 1989).

40 CFR 60.7, Notification and record keeping. Timely notification of the items listed to the Department (South District), Palm Beach County Public Health Unit (PBCPHU), and EPA.

PERMITTEE:
Okeelanta Corporation

Permit Number: AC 50-191876
PSD-FL-169
Expiration Date: March 1, 1993

SPECIFIC CONDITIONS:

40 CFR 60.8, Compliance tests. Minimum of 30 days prior notice of the initial compliance tests which must be conducted between 60 to 180 days of initial startup of the source to the Department and EPA.

40 CFR 60.42b, Standard for sulfur dioxide. Sulfur content of the No. 2 distillation oil fuel shall not exceed 0.5%. Annual off-season average shall not exceed 0.3% sulfur. The permittee shall maintain fuel analysis or receipts to confirm compliance with this condition.

40 CFR 60.43b, Standard for particulate matter. Visible emissions shall not exceed 20% opacity (6-minute average), except for one 6-minute period per hour of not more than 27% opacity.

40 CFR 60.44b, Standard for nitrogen oxides for high heat release boiler No. 16, expressed as NO_2, is 0.20 lbs/MMBtu.

40 CFR 60.45b, Sulfur dioxide compliance tests, fuel receipts or analysis for sulfur content is required to confirm compliance with this condition.

40 CFR 60.46b, Particulate and nitrogen oxides compliance tests. Method 9 test required to determine compliance with the opacity standard. Method 7, 7A, or 7E test for nitrogen oxides.

40 CFR 60.47b, Sulfur dioxide monitoring. Fuel analysis or receipts required to confirm compliance with this condition.

40 CFR 60.48b, Particulate and nitrogen oxides monitoring. Continuous emissions monitor required to measure opacity.

40 CFR 60.49b, Reporting and record keeping requirements. Permittee required to report date of initial start up, design heat input capacity, fuels used, annual capacity factor, performance test data, plan to monitor NO_x, nitrogen content of the distillate oil, opacity, nitrogen dioxide emissions, monitor down time, "F" factor, exceedances, and other information required by this paragraph.

Operation Requirements

8. Only No. 2 fuel oil containing a maximum of 0.5% sulfur (off-season average of 0.3% sulfur) shall be used as fuel.

PERMITTEE:
Okeelanta Corporation

Permit Number: AC 50-191876
PSD-FL-169
Expiration Date: March 1, 1993

SPECIFIC CONDITIONS:

9. Maximum heat input to the boiler shall not exceed 1,463 gallons per hour of No. 2 distillate fuel oil (205 MMBtu/hr).

10. The boiler shall not operate for more than 175 days (4,200 hours) during any 12 month period. The boiler shall only operate during the off-season months (March through October).

11. Steam production shall not exceed 150,000 lbs/hr.

Administrative Requirements

12. The permittee shall maintain a log that shows the boiler's operation time, steam production, and fuel consumption.

13. The Department's South District and the PBCPHU shall be notified in writing at least 30 days in advance of the initial compliance test and 15 days in advance of any annual compliance tests to be conducted on this boiler.

14. Stack test results shall be submitted to the Department and the PCBPHU within 45 days of the test.

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

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

Issued this 29th day
of July, 1991.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Carol M. Browner

Carol M. Browner, Secretary

Best Available Control Technology (BACT) Determination
Okeelanta Corporation
Palm Beach County

The applicant plans to permanently install a 205 MMBtu/hr No. 2 oil-fired steam boiler at their facility 6 miles south of South Bay, Florida. The boiler will be used to supply process steam. The boil is scheduled to operate during the off-season of April through Octob (4,200 hours) when the other boilers at this facility are shutdown.

A BACT determination is required for particulates and sulfur dioxide as set forth in the Florida Administrative Code Rule 17-2.600(6) - Emissions Limiting and Performance Standards. In addition, the Department performed a BACT determination for nitrogen oxides (NOx) since those emissions are greater than the PSD significant rate of 40 tons per year.

<u>BACT Determination Request by the Applicant</u>:

Particulate, sulfur dioxide, nitrogen oxides emissions to be controlled by the firing of No. 2 fuel oil with a 0.5% sulfur content

<u>Date of Receipt of a BACT Application</u>:

January 29, 1991

<u>BACT Determined by DER</u>:

The amount of particulate and sulfur dioxide emissions from the boile will be limited by the firing of No. 2 fuel oil with a 0.3% off seaso average and a 0.5% maximum sulfur content.

Nitrogen oxides emissions shall not exceed 0.18 lbs/MMBtu heat input using low NOx burners/flue gas recirculation.

<u>BACT Determination Rationale</u>:

Sulfur in fuel is a primary air pollution concern in that most of the fuel sulfur becomes SO_2 and particulate emissions from fuel burning are related to the sulfur content. The Department has determined tha the firing of No. 2 fuel oil with an off-season average of 0.3% sulfu and maximum of 0.5% sulfur content is BACT for particulates and SO_2. These sulfur content limitations are representative of what has been recently established as BACT for oil-fired equipment.

PART B
PSD REPORT

Part B – PSD Report

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1.0 EXECUTIVE SUMMARY

Okeelanta Corporation (Okeelanta) is proposing a modification to its existing Boiler No. 16 located at its sugar mill and cogeneration facility south of South Bay, Palm Beach County, Florida. The proposed modification consists of converting Boiler No. 16 to a dual fuel-fired unit capable of burning natural gas and No. 2 fuel oil, increasing the maximum heat input to 211 million British thermal units per hour (MMBtu/hr), and increasing the permitted operating hours to 8,760 hr/yr.

Boiler No. 16 is currently permitted to burn only No. 2 fuel oil. Boiler No. 16 is permitted to operate during any season of the year, but is limited to 7,080 hours a year operation. During the off-season months of March through October, Boiler No. 16 is only permitted to operate 175 days (4,200 hours). During the sugar cane processing season, Boiler No. 16 may only operate when one or more of the cogeneration boilers are down.

Okeelanta made application and was issued a U.S. Environmental Protection Agency (EPA) prevention of significant deterioration (PSD) permit (Permit No. PSD-FL-169) in 1991 for Boiler No. 16. Boiler No. 16 was originally constructed to provide steam to the Okeelanta sugar refining operations during the off-season. The permit was modified in 1993, and the boiler currently operates under permit AO50-257065, issued November 29, 1994. With this modification, the boiler became a backup during startup, debugging, and testing of the cogeneration boilers. Currently, Boiler No. 16 can only operate when one or more of the cogeneration boilers are down.

Modifications to the operational limits of Boiler No. 16, described in this application, will result in potential emission increases that will exceed PSD significant emission rates and therefore will require PSD review. This application contains the technical information developed in accordance with PSD regulations as promulgated by the U.S. Environmental Protection Agency (EPA) and implemented through delegation to the Florida Department of Environmental Protection (FDEP). It presents an evaluation of regulated pollutants subject to PSD review, a demonstration of Best Available Control Technology (BACT), and an assessment of potential air quality impacts associated with the project. Through this application, Okeelanta requests that the FDEP issue a PSD construction permit for this project.

1.1 PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REVIEW

The permitting of this project in Florida requires an air construction permit and PSD review approval. The project will be a modification to an existing air emission source in Palm Beach County. The EPA has implemented regulations requiring PSD review for new or modified sources that increase air emissions above certain threshold amounts. PSD regulations are promulgated under Title 40 of the Code of Federal Regulations (CFR), Part 52.21, and are implemented in Florida through delegation to the FDEP. FDEP has adopted the EPA PSD regulations as Rule 62-212.400, Florida Administrative Code (F.A.C.).

The maximum future emissions and the net increase in emissions associated with this project are presented in Table 1-1, all in tons per year (TPY). The current actual emissions for Boiler No. 16 were assumed to be zero, since the boiler has operated very little in the last several years. Based on the net emissions increase due to the proposed project, a PSD review is required for each of the following regulated pollutants:

- nitrogen oxides (NO_x),
- particulate matter with aerodynamic particle size diameter of 10 microns or less (PM_{10}),
- carbon monoxide (CO), and
- beryllium (Be).

The increase in emissions of other regulated pollutants will not be significant.

Palm Beach County has been designated as an attainment or maintenance area for all criteria pollutants. The county is also classified as a PSD Class II area for SO_2 and NO_x. As a result, the new source review will follow PSD regulations pertaining to such designations.

1.2 BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

For the proposed modification to Boiler No. 16, a BACT analysis was conducted for each pollutant for which the net increase exceeds the EPA/FDEP significance threshold and, is therefore, subject to BACT review. The proposed BACT to control NO_x emissions from Boiler No. 16 is the use of low-NOx burners and flue gas recirculation. PM/PM_{10} and Be emissions will be controlled by firing natural gas or very low sulfur content No. 2 distillate fuel oil (i.e., 0.05% sulfur or less). Okeelanta is proposing to control CO emissions from Boiler No. 16 with good combustion practices.

As per Rules 62-296.406(2) and 62-296.406(3), F.A.C., a BACT analysis is required for PM and SO_2 even if the net increase of emissions does not exceed the significance threshold. As stated earlier, the BACT for PM has been determined to be burning natural gas or very low sulfur content No. 2 distillate fuel oil. The BACT for SO_2 has also been determined to be very low sulfur content fuel oil.

1.3 AIR QUALITY ANALYSIS

An air quality impact analysis was conducted to determine if the proposed project would cause or contribute to a violation of any national or Florida Ambient Air Quality Standard (AAQS) or allowable PSD increment. It was demonstrated that emissions from the facility as modified, and described in this application, would not result in ambient concentrations above the AAQS or the PSD Class II increments. As a result, the project will not cause or contribute to any adverse impacts on air quality. Impacts due to the proposed modification on soils, vegetation, visibility, and air quality related values (AQRVs) were analyzed and found not to be adverse.

1.4 SUMMARY OF ANALYSIS

Results from the analyses presented in this PSD air permit application lead to the following conclusions:

- The proposed BACT for each applicable pollutant provides the maximum degree of emissions reduction based on energy, environmental, and economic impacts and technical feasibility.
- National or Florida Ambient Air Quality Standards will not be exceeded as a result of the proposed modification.
- Applicable PSD increments will not be exceeded as a result of the proposed modification.
- No adverse effects on soils, vegetation, visibility, or AQRVs in the PSD Class I area are predicted.

As documented in this application, the proposed modification will be designed to operate in compliance with all applicable Federal and state air quality rules and regulations.

1.5 PSD REPORT ORGANIZATION

This PSD Report is divided into seven major sections, including this summary section:

- Section 2.0 presents a description of the project, including air emissions and stack parameters;
- Section 3.0 provides a review of the PSD requirements applicable to the proposed project;
- Section 4.0 includes the control technology review and BACT analysis;
- Section 5.0 presents the air modeling approach and results to assess compliance of the proposed project with AAQS, PSD increments, and good engineering practice (GEP) stack height regulations;
- Section 6.0 provides the additional impact analyses for soils, vegetation, and visibility, as well as the AQRV analysis for the PSD Class I area.

Table 1-1. Net Emissions Increase for Modification to Okeelanta Boiler No. 16

Pollutant	Net Increase in Emissions[a] (TPY)	PSD Significant Rate (TPY)	PSD Review Applies?
Particulate Matter (PM)	22.16	25	No
Particulate Matter (PM_{10})	22.16	15	Yes
Sulfur Dioxide	39.38	40	No
Nitrogen Oxides	113.78	40	Yes
Carbon Monoxide	140.90	100	Yes
Volatile Organic Compounds	27.73	40	No
Sulfuric Acid Mist	1.75	7	No
Lead	6.23E-03	0.6	No
Mercury	2.09E-03	0.1	No
Beryllium	2.04E-03	4.00E-04	Yes
Fluorides	--	3	No

[a] Since Boiler No. 16 has operated very little in the last several years, the current emissions from Boiler No. 16 were assumed to be zero. Thus, the net increase in emissions are equal to the future maximum emissions of Boiler No. 16.

2.0 PROJECT DESCRIPTION

2.1 SITE DESCRIPTION

The Okeelanta facility consists of two operating units: the Okeelanta Corporation (Okeelanta) sugar mill and refinery, and the Okeelanta Power Limited Partnership (OPLP) cogeneration facility. The facility is located approximately six miles south of South Bay, Florida, in Palm Beach County (See Attachment OC-FI-1). The Okeelanta Sugar Mill receives sugar cane from the surrounding cane fields and presses it into raw sugar. The fibrous byproduct material from the sugar cane processing is called bagasse and is burned in onsite boilers for fuel. The raw sugar is either stored or sent to the sugar refinery where it is processed into refined sugar. Both raw sugar and refined sugar can be shipped offsite to customers by truck or rail. Refer to Attachments OC-FI-3a and OC-FI-3b of the permit application form for a flow diagram of the overall process.

Steam is used in the raw sugar production process. To supply steam, the Okeelanta Sugar Mill consists of eight bagasse-/oil-fired boilers (Boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15) and one oil-fired boiler (Boiler No. 16) which provide steam to the sugar mill. Boiler Nos. 4, 5, 10, 12 and 14 have not operated since November 1998 and Boiler Nos. 6 and 11 have not operated since January 1999. Boiler No. 16 is currently fired solely with No. 2 fuel oil. Boiler No. 16 last operated in March 1999. In recent years, the steam needed in the sugar mill has been provided by the OPLP cogeneration facility.

The OPLP cogeneration facility meets the steam requirements of the sugar mill with three boilers. These boilers burn biomass (wood, bagasse, etc;) and No. 2 fuel oil. These boilers are also permitted to generate up to 79.4 megawatts of electricity (1-hour average) for sale to the grid.

2.2 BOILER NO. 16 MODIFICATION

Boiler No. 16 is currently operating under Permit No. AO50-257065, which DEP issued November 29, 1994 (copy contained in OC-EU1-J13). Boiler No. 16 is limited to 175 days of operation during the off-season months of March through October. During the crop season (November through February), the heat input of Boiler No. 16 is limited to the equivalent reduction in heat input from No. 6 fuel oil for Boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15. The boiler is permitted to operate while combusting No. 2 fuel oil at a maximum of 205 MMBtu/hr. The maximum sulfur content of the No. 2 fuel oil is limited to 0.5% during the crop season and 0.3% during the off-season. The maximum allowable steam rate for Boiler No. 16 is 150,000 lb/hr. To control nitrogen oxide (NO_x) emissions, Boiler No. 16 is equipped with low NO_x burners and is designed for 40% flue gas recirculation.

The current permitted emission rate for particulate matter (PM) is 0.054 lb/MMBtu. For particulate matter with a diameter of 10 microns or less (PM_{10}), the permitted emission rate is 0.027 lb/MMBtu. Sulfur dioxide (SO_2) emissions are limited to 0.51 lb/MMBtu, while NO_x emisssions are limited to 0.18 lb/MMBtu. The permitted emission rate for carbon monoxide (CO) is 0.20 lb/MMBtu. Volatile organic compound emissions (VOC) are limited to 0.09 lb/MMBtu, while visible emissions (VE) are limited to 20 percent opacity (six-minute average) except for 27 percent for one six-minute period per hour. These emission rates were based on design information for the boiler. Since Boiler No. 16 has operated very little in the last several years, it is assumed that current emissions for Boiler No. 16 are zero.

Okeelanta is proposing to convert Boiler No. 16 into a dual fuel-fired unit capable of burning both natural gas and No. 2 fuel oil. The existing low NOx burner will be replaced with a new low NO_x burner that is capable of firing both natural gas and No. 2 fuel oil. The maximum allowable heat input will increase from 205 MMBtu/hr to 211 MMBtu/hr for natural gas firing. Okeelanta is proposing to use No. 2 fuel oil with a maximum sulfur content of 0.05%. Okeelanta is also proposing to change the permitted annual operating hours to 8,760 to allow Boiler No. 16 to operate throughout the year.

2.3 PROPOSED BOILER NO. 16 EMISSIONS

The estimated maximum hourly emissions for Boiler No. 16, operating at the maximum heat input of 211 MMBtu/hr for natural gas and 202 MMBtu/hr for No. 2 fuel oil, are presented in Table 2-1. The basis for the maximum emissions are shown in the footnotes to the table and are explained below.

The maximum heat input for No. 2 fuel oil is based on the current allowable maximum heat input for Boiler No. 16. Maximum steam production of Boiler No. 16 is 150,000 lb/hr. The boiler is designed to operate at a steam condition of 380 psig and 650° F. Based on a fuel oil heating value of 136,000 Btu/gal, No. 2 fuel oil can be burned at up to 1,485 gallons per hour (gal/hr). This is a slight increase from the current permitted value of 1,436 gal/hr. In order to reduce monitoring and record keeping, it is requested that the heat input rates and steam production rates be based on a daily 24-hr average.

The proposed maximum allowable heat input for natural gas firing is 211 MMBtu/hr (24-hr average). This heat input is equivalent to 206,862 standard cubic feet (scf) per hour assuming a heating value of 1,020 Btu/scf.

As shown in Table 2-1, the maximum PM and PM_{10} emissions expected from this project are 22.16 tons per year (TPY). The emission factors for PM and PM_{10} due to No. 2 fuel oil firing are based on emission test results. Testing performed on Boiler No. 16 since 1994 shows that this emission factor is appropriate for the boiler. A summary of the test results for Boiler No. 16 is presented in Table 4-5.

The emission limits for NO_x and SO_2 are proposed BACT emission limits based on the results of the BACT analysis that are presented in Section 4.0. Several burner manufacturers have guaranteed a NO_x emission limit of 0.055 lb/MMBtu at 211 MMBtu/hr for natural gas firing with up to 0.15 lb/MMBtu at 202 MMBtu/hr for fuel oil firing. SO_2 emissions will be controlled by limiting the maximum fuel oil sulfur content to 0.05%.

The emission limits for CO are proposed BACT emission limits based on vendor information. The vendor information indicates maximum CO emissions of 0.15 lb/MMBtu for natural gas firing and 0.16 lb/MMBtu for fuel oil firing. CO emissions will be controlled by good combustion practices.

To determine the maximum potential annual emissions for the proposed project, the maximum hourly emissions due to either fuel type were used.

2.4 SITE LAYOUT AND STRUCTURES

A plot plan of the Okeelanta Sugar Mill is presented in Attachment OC-FI-2. The dimensions of the buildings and structures are presented in Section 6.0.

2.5 STACK PARAMETERS

The existing stack serving Boiler No. 16 is 75 feet. This stack will continue to be used in the future. Stack parameters for Boiler No. 16, both current and future, are presented in Table 2-2.

Table 2-1. Future 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)	Hourly Emissions (lb/hr)	Annual Emissions[b] (TPY)	No. 2 Fuel Oil Combustion: Emission Factor (lb/1000 gal	Emission Factor (lb/MMBtu)	Ref.	Activity Factor[a] (MMBtu/hr)	Hourly Emissions (lb/hr)	Annual Emissions[c] (TPY)	Annual Emissions With Maximum Fuel Oil Firing[d] (TPY)	Maximum Annual Emissions Due to Any Combination[e] (TPY)
Particulate Matter (PM)	1.9	1.86E-03	1	211	0.39	1.72	--	0.032	4	202	6.46	21.76	22.16	22.16
Particulate Matter (PM_{10})	1.9	1.86E-03	1	211	0.39	1.72	--	0.032	4	202	6.46	21.76	22.16	22.16
Sulfur dioxide (SO_2)	0.6	5.88E-04	1	211	0.12	0.54	7.85	0.058	5	202	11.66	39.26	39.38	39.38
Nitrogen oxides (NO_x)	--	0.055	2	211	11.61	50.83	--	0.15	2	202	30.30	102.02	113.78	113.78
Carbon monoxide (CO)	--	0.15	2	211	31.65	138.63	--	0.16	2	202	32.32	108.82	140.90	140.90
VOC	--	0.03	2	211	6.33	27.73	--	0.03	2	202	6.06	20.40	26.82	27.73
Sulfuric acid mist (SAM)	--	3.60E-05	3	211	7.60E-03	0.03	--	0.0026	6	202	0.52	1.75	1.75	1.75
Lead (Pb)	5.E-04	4.90E-07	1	211	1.03E-04	4.53E-04	--	9.00E-06	5	202	1.82E-03	6.12E-03	6.23E-03	6.23E-03
Mercury (Hg)	2.6E-04	2.55E-07	1	211	5.38E-05	2.36E-04	--	3.00E-06	5	202	6.06E-04	2.04E-03	2.09E-03	2.09E-03
Beryllium (Be)	1.2E-05	1.18E-08	1	211	2.49E-06	1.09E-05	--	3.00E-06	5	202	6.06E-04	2.04E-03	2.04E-03	2.04E-03
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. Proposed emission limits. 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 emission test results for Boiler No. 16.
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).

Footnotes:

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

[b] Based on maximum proposed operation of 8,760 hours.

[c] Based on maximum proposed limit for 0.05% sulfur fuel oil of 10,000,000 gallons/yr, equivalent to 6,733 hours per year at 202 MMBtu/hr (1,360,000 MMBtu/yr).

[d] Based on emissions due to maximum fuel oil usage (10,000,000 gal/yr or 1,360,000 MMBtu/yr) and the remaining due to natural gas (435,830 MMBtu/yr).

[e] Maximum emissions predicted for either natural gas combustion only, No. 2 fuel oil combustion only, or a combination of No. 2 fuel oil and natural gas combustion.

Sample Calculations:

Hourly Emissions = Emission Factor x Activity Factor

Annual Emissions = Hourly Emissions x hours of operation (hrs/yr) / 2,000 (lb/ton)

Annual Emissions due to firing both fuels = Annual Emissions due to fuel oil + [(Hourly emissions due to natural gas x (8,760 hrs/yr - 6,733 hrs/yr)/ 2,000 (lb/ton)

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

	Steam Production Rate (lb/hr)	Stack Height (ft)	Stack Diameter (ft)	Gas Parameters Flow Rate (acfm)	Gas Parameters Velocity (ft/s)	Gas Parameters Temperature (deg F)
Boiler No. 16	150,000	75	5	88,200	75	410

Notes:
acfm = actual cubic feet per minute
deg F = degrees Fahrenheit
ft = feet
ft/s = feet per second

3.0 AIR QUALITY REVIEW REQUIREMENTS

Federal and state air regulatory requirements for a major modification to an existing major source of air pollution are discussed in Sections 3.1 to 3.4. The applicability of these regulations to the modified Boiler No. 16 is presented in Section 3.5. These regulations must be satisfied before the proposed project can be approved.

3.1 NATIONAL AND STATE AAQS

The existing applicable national and Florida 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. 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-hr secondary standard of 260 $\mu g/m^3$, 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 Clean Air Act (CAA) must be reviewed and a pre-construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA; therefore, PSD approval authority has been granted to the FDEP.

A "major facility" is defined as any one of 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 CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. Once a new source is determined to be a "major facility" for a particular pollutant, any pollutant emitted in amounts greater than the PSD significant emission rates is subject to PSD review. For an existing source for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emission rates. The PSD significant emission rates are shown in Table 3-2.

The EPA class designation and allowable PSD increments are presented in Table 3-1. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications are designated based on criteria established in the Clean Air Act 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 increments.

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 the federal PSD regulations by reference (Rule 62-212.400, F.A.C.). Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new facility also must be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

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 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 is defined in 40 CFR 52.21 (b)(12), as:

> An emissions limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the Act which would be emitted by any proposed major stationary source of major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determination is achievable through application of production processes and available methods, systems, and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant, which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means, which achieve equivalent results.

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 primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978;

1980). Guidelines for the evaluation of BACT can be found in EPA's *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978) and in the *PSD Workshop Manual* (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

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 new source performance standards (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. The cost-benefit analysis required the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgement, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

3.2.3 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source or major modification subject to PSD review, and for each pollutant for which the increase in emissions exceeds the PSD significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication *Guideline on Air Quality Models* (EPA, 1980).

To address compliance with AAQS and PSD Class II increments, a source impact analysis must be performed for the criteria pollutants. However, this analysis is not required for a specific pollutant if the net increase in impacts as a result of the new source or modification is below significant impact levels, as presented in Table 3-1. The significant impact levels are threshold levels that are used to determine the level of air impact analyses needed for the project. If the new or modified source's impacts are predicted to be less than significant, then the source's impacts are assumed not to have a significant adverse affect on air quality and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance AAQS and PSD increments.

EPA has proposed significant impact levels for Class I areas as follows:

SO_2	3-hour	1 $\mu g/m^3$
	24-hour	0.2 $\mu g/m^3$
	Annual	0.1 $\mu g/m^3$
PM_{10}	24-hour	0.3 $\mu g/m^3$
	Annual	0.2 $\mu g/m^3$
NO_2	Annual	0.1 $\mu g/m^3$

Although these levels have not been officially promulgated as part of the PSD review process and may not be binding for states in performing PSD review, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. The EPA action to incorporate Class I significant impact levels in the PSD process is part of implementing NSR provisions of the 1990 CAA Amendments. Because the process of developing the regulations will be lengthy, EPA believes that the proposed rules concerning the significant impact levels is appropriate in order to assist states in implementing the PSD permit process.

Various lengths of record for meteorological data can be used for impact analysis. A 5-year period is normally used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The meteorological data are selected base on an evaluation of measured weather data from a nearby weather station that represents weather conditions at the project site. The criteria used in this evaluation include determining the distance of the project site to the weather station; comparing topographical and land use features between the locations; and determining availability of necessary weather parameters.

The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is important because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If fewer than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable baseline date; and
2. The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM(TSP) concentrations, or February 8, 1988, for NO_2 concentrations, but that were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and therefore affect PSD increment consumption:

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM(TSP) concentrations, and after February 8, 1988, for NO_2 concentrations; and
2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM(TSP), and February 8, 1988, in the case of NO_2.
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application.
3. The trigger date, which is August 7, 1977, for SO_2 and PM(TSP), and February 8, 1988, for NO_2.

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m), any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that Florida DEP may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2.

3.2.5 SOURCE INFORMATION/GOOD ENGINEERING PRACTICE STACK HEIGHT

Source information must be provided to adequately describe the proposed project. The information required for this project is presented in Section 2.0.

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

1. 65 meters (m); or
2. A height established by applying the formula:

   $Hg = H + 1.5L$

   where:
   - Hg = GEP stack height,
   - H = Height of the structure or nearby structure, and
   - L = Lesser dimension (height or projected width) of nearby structure(s); or
3. 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 km. Although GEP stack height regulations require that the stack height used in modeling for determining compliance with 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.

3.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21(o) and Rule 62-212.400, F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions, all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review. A new major facility is required to undergo this review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant.

3.4 EMISSION STANDARDS

3.4.1 NEW SOURCE PERFORMANCE STANDARDS

The 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." Boiler No. 16 is subject to NSPS Subpart Db for Industrial Steam Generating Units.

3.4.2 FLORIDA RULES

FDEP regulations for fossil fuel steam generators with less than 250 MMBtu/hr of heat input are covered in Rule 62-296.406. These rules require that "new" 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 best available control technology.

3.5 PSD APPLICABILITY

3.5.1 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 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.

3.5.2 PSD REVIEW

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 million Btu/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.

Since Boiler No. 16 has operated very little in the last several years, current actual (baseline) emissions for Boiler No. 16 are considered to be zero. Therefore the changes in emissions due to this project are the future maximum emissions as presented in Table 2-1. As shown in Table 3-3, the potential increase in emissions due to the proposed modification of Boiler No. 16 exceeds the PSD significant emission rates for PM_{10}, CO, NO_x, and Be. As a result, PSD review applies for these pollutants.

Source Impact Analysis

A source impact analysis was performed for PM_{10}, NO_x, and CO emissions resulting from the proposed modification (refer to Section 5.0). As shown in Table 3-4, the predicted increases in impacts due to the proposed modification to Boiler No. 16 are predicted to be below the significant impact levels for PM_{10}, NO_x, and CO. As a result, a modeling analysis incorporating the impacts from other sources is not required for these pollutants.

Emission Standards

Based on the maximum heat input to the proposed boiler and the type of fuel burned, the boiler will be subject to the federal NSPS for industrial boilers (40 CFR 60, Subpart Db). The Subpart Db standards are summarized in Table 3-5. The NSPS for SO_2 require that either the boiler meet an emission limit of 0.8 lb/MMBtu and achieve 90 percent reduction in SO_2 emissions or burn very low fuel. Very low fuel is defined as distillate fuel with a maximum sulfur content of 0.5 percent by weight, or a fuel oil with an equivalent SO_2 emission rate of 0.5 lb/MMBtu or less. Currently, Boiler No. 16 complies with the NSPS for SO_2 by burning very low sulfur distillate fuel oil with a maximum sulfur content of 0.5 percent. In the future, Okeelanta proposes Boiler No. 16 will comply with the NSPS for SO_2 by burning very low sulfur distillate fuel oil with a maximum sulfur content of 0.05 percent.

The applicable NSPS emission limit for NO_x is 0.2 lb/MMBtu heat input for an industrial boiler firing distillate oil or natural gas and having a high heat release rate [i.e., greater than 70,000 British thermal units per hour per square foot (Btu/hr-ft^2)]. Currently, NO_x emissions are limited to 0.18 lb/MMBtu, which is lower than the NSPS. The proposed NO_x emission limit for the modified Boiler No. 16 is 0.055 lb/MMBtu for natural gas firing and 0.15 lb/MMBtu for fuel oil firing.

There is no particulate matter emission limit for industrial boilers firing very low sulfur fuel oil. As shown in Table 2-1, Okeelanta proposes an emission limit of 0.032 lb/MMBtu for fuel oil firing, which is based on historic test data. There is an opacity limitation of 20 percent, as shown in Table 3-5.

<u>Ambient Monitoring</u>

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate.

Ambient air monitoring for a period of up to 1 year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

Based on the increase in emissions from the proposed modification (see Table 3-3), a pre-construction ambient monitoring analysis is required for PM_{10}, NO_x, and CO and monitoring data is required to be submitted as part of the application. However, if the net increase in impacts of a pollutant is less than the applicable *de minimis* monitoring concentration, then an exemption from submittal of pre-construction ambient monitoring data may be obtained [40 CFR 52.21(i)(8)]. In addition, if EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

Pre-construction monitoring data for PM_{10}, NO_x, and CO may be exempted for this project because, as shown in Table 3-4 and in Section 5.0, the proposed modification's impacts are predicted to be below the applicable *de minimis* monitoring concentrations.

<u>GEP Stack Height Impact Analysis</u>

The Boiler No. 16 stack is 75 ft high, and will not change due to this project. This stack height does not exceed the *de minimis* good engineering practice (GEP) stack height of 65 meters (213 ft).

3.5.3 NONATTAINMENT REVIEW

The project site is located in Palm Beach County, which is classified as an attainment or maintenance area for all criteria pollutants. Therefore, nonattainment requirements are not applicable.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels ($\mu g/m^3$)

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

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 $\mu g/m^3$ (3-year average of 98th percentile) and an annual standard of 15 $\mu g/m^3$ (3-year average at community monitors). Implementation of these standards are many years away. The ozone standard was modified to be 0.08 ppm for 8-hour average; achieved when 3-year average of 99th percentile is 0.08 ppm or less. FDEP has not yet adopted 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 $\mu g/m^3$ 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	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM_{10})	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour
MWC Organics	NSPS	3.5×10^{-6}	NM
MWC Metals	NSPS	15	NM
MWC Acid Gases	NSPS	40	NM
MSW Landfill Gases	NSPS	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.

NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
$\mu g/m^3$ = 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.
[c] Any emission rate of these pollutants.

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

Table 3-3. Net Emissions Increase for Modification to Okeelanta Boiler No. 16

Pollutant	Net Increase in Emissions[a] (TPY)	PSD Significant Rate (TPY)	PSD Review Applies?
Particulate Matter (PM)	22.16	25	No
Particulate Matter (PM_{10})	22.16	15	Yes
Sulfur Dioxide	39.38	40	No
Nitrogen Oxides	113.78	40	Yes
Carbon Monoxide	140.90	100	Yes
Volatile Organic Compounds	27.73	40	No
Sulfuric Acid Mist	1.75	7	No
Lead	6.23E-03	0.6	No
Mercury	2.09E-03	0.1	No
Beryllium	2.04E-03	4.00E-04	Yes
Fluorides	--	3	No

[a] Since Boiler No. 16 has operated very little in the last several years, the current emissions from Boiler No. 16 were assumed to be zero. Thus, the net increase in emissions are equal to the future maximum emissions of Boiler No. 16.

Table 3-4. Impacts of Boiler No. 16 Modification Compared to Class II Significant Impact Levels and Ambient Monitoring *De Minimis* Levels

Pollutant	Averaging Time	Maximum Concentration[a] ($\mu g/m^3$)	EPA Class II Significant Impact Levels ($\mu g/m^3$)	*De Minimis* Monitoring Concentration ($\mu g/m^3$)	Ambient Monitoring Review Applies?
Particulate Matter (PM_{10})	Annual	0.10	1	NA	NA
	24-hour	1.13	5	10	No
Nitrogen Oxides	Annual	0.45	1	14	No
Carbon Monoxide	8-hour	16	500	575	No
	1-hour	38	2,000	NA	NA

[a] Highest concentration from significant impact analysis (See Section 5.0).
Note: NA = Not Applicable

Table 3-5. NSPS for Steam Generating Units With Heat Input Between 100 MMBtu/hr and 250 MMBtu/hr (40 CFR 60, Subpart Db)

Pollutant	Annual Capacity Factor on Oil (%)	Standard
Sulfur Dioxide	31-100	0.80 lb/10^6 Btu; 90% reduction[a]
	0-30	0.50 lb/10^6 Btu[b]
Particulate Matter	0-100	Conventional or emerging SO_2 control technology used: 0.10 lb/10^6 Btu; SO_2 control technology not used: No PM limit
	0-100	20% opacity, except for 27% for one 6-minute period per hour
Nitrogen Oxides	11-100	Distillate oil or natural gas only: Low heat release rate -- 0.10 lb/10^6 Btu High heat release rate -- 0.20 lb/10^6 Btu Duct Burner in combined cycle -- 0.20 lb/10^6 Btu Residual oil only: Low heat release rate -- 0.30 lb/10^6 Btu High heat release rate -- 0.40 lb/10^6 Btu Duct Burner in combined cycle -- 0.40 lb/10^6 Btu
	0-10	Residual oil with %N less than or equal to 0.3, distillate oil, or natural gas: No NO_x standard

[a] Percentage reduction requirement does not apply if burning very low sulfur fuel (<0.50 lb/10^6 Btu).

[b] Also applies if oil is fired in a duct burner of a combined cycle unit and 30% or less of the heat input to the steam-generating unit is from oil combustion in the duct burner.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may potentially be emitted above significant emission rates. For the proposed modification to Boiler No. 16, the control technology review requirements are applicable to emissions of PM_{10}, SO_2, CO, Be and NO_x (see Sections 3.4.2 and 3.5.2).

This section presents the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as EPA's current policy guidelines requiring a top-down approach. A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies [see 40 CFR 52.21(b)(12)]. The analysis must, by definition, be specific to the project (i.e., case-by-case). As described in Section 3.2.2, BACT is determined on a case-by-case basis after taking into account the specific energy, environmental and economic impacts and other costs of the project.

Maximum emissions for Boiler No. 16 are based on operating 8,760 hours per year at 211 MMBtu/hr heat input for natural gas firing and 202 MMBtu/hr heat input for fuel oil firing. Boiler No. 16 is an existing boiler with Coen's Low NO_x Burners and 40% flue gas recirculation (FGR). Future emissions will be controlled by the use of advanced low-NO_x burners (LNB) and FGR, and by burning very low sulfur No. 2 distillate fuel oil (i.e., 0.05% sulfur or less). Okeelanta proposes replacing the existing LNB with a new LNB that is capable of firing both fuel oil and natural gas. Vendor quotes guaranteed a NO_x emission rate of 0.055 lb/MMBtu for natural gas firing and up to 0.15 lb/MMBtu for fuel oil firing with a new dual-firing LNB and the existing FGR system. These technologies result in the best available control technology considering economic, environmental, and energy impacts.

4.2 BACT DETERMINATION FOR SO_2 EMISSIONS

The current BACT limit for SO_2 emissions is to limit the fuel used in Boiler No. 16 to No. 2 fuel oil with a maximum sulfur content of 0.5 percent. The proposed BACT for SO_2 emissions from Boiler No. 16 is based on burning No. 2 distillate fuel oil with a sulfur content of 0.05% or less.

As part of the BACT analysis, a review of previous SO_2 BACT determinations for industrial boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's webpage was performed. Summaries of BACT determinations for both fuel oil- and natural gas-fired boilers from this review are presented in Tables 4-1 and 4-2, respectively. From this review, it is evident that SO_2 BACT determinations for industrial boilers have typically been fuel specifications.

Since the level of SO_2 emissions is directly related to the amount of sulfur in the fuel, a low sulfur-containing fuel can be used to meet the SO_2 limitation specified by the NSPS regulations for industrial boilers. Okeelanta proposes to use natural gas and 0.05 percent sulfur fuel oil for the future operations of Boiler No. 16 and to limit the annual fuel oil usage to 10,000,000 gallons per year. These conditions result in less than 40 TPY of SO_2 emissions. There is no other technology that could achieve lower SO_2 emissions. Therefore, the proposed BACT for SO_2 emissions is to use natural gas and No. 2 fuel oil with a maximum sulfur content of 0.05 percent and limit fuel oil usage to 10,000,000 gallons per year. The resulting emissions are comparable to the emissions resulting from other BACT determinations, and are consistent with previous BACT determinations.

4.3 BACT DETERMINATION FOR PM_{10} AND BERYLLIUM (BE) EMISSIONS

Maximum PM_{10} emissions from Boiler No. 16 are estimated to be 22.16 TPY, and BE emissions are 0.002 TPY. These maximum emissions are due to both natural gas and fuel oil firing. Okeelanta proposes to use natural gas and No. 2 fuel oil with a maximum sulfur content of 0.05 percent. Both of these fuels are clean burning fuels and result in very low PM_{10} and Be emissions.

As part of the BACT analysis, a review of previous PM/PM_{10} BACT determinations for industrial boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's webpage was performed. Summaries of BACT determinations for both fuel oil- and natural gas-fired boilers from this review are presented in Tables 4-3 and 4-4, respectively.

From the review of previous BACT determination, it is evident that PM/PM_{10} BACT determinations for both oil-fired and natural gas-fired industrial boilers have typically been fuel specifications and good design and operating practices. Proposed maximum PM_{10} emissions from Boiler No. 16 are 0.032 lb/MMBtu when firing No. 2 fuel oil and 0.0019 lb/MMBtu for natural gas. The No. 2 fuel oil factor is based on previous emission test results for Boiler No. 16. A summary of these results is presented in Table 4-5.

There are two determinations for fuel oil fired industrial boilers; the emission limits for these determinations are 0.05 lb/MMBtu and 0.08 lb/MMBtu. The proposed BACT for Boiler No. 16 would result in emissions below this range for fuel oil firing. The emission limits from the determinations for natural gas-fired industrial boilers range from 0.002 lb/MMBtu to 0.03 lb/MMBtu. The proposed BACT for Boiler No. 16 would result in emissions at the lower end of this range for emissions due to natural gas firing.

It would not be economical to install any add-on control equipment to decrease PM_{10} and Be emissions any further than what is achievable through burning clean fuels (i.e., natural gas and No. 2 fuel oil with a maximum sulfur content of 0.05%). Therefore, clean fuels are proposed as BACT for PM_{10} and Be emissions.

4.4 BACT DETERMINATION FOR NO_X EMISSIONS

4.4.1 IDENTIFICATION OF NO_X CONTROL TECHNOLOGIES FOR INDUSTRIAL BOILERS

In this section, the control technologies capable of reducing NO_x emissions produced by industrial boilers will be evaluated relative to their potential application as BACT for future operations of Boiler No. 16. All potentially applicable control technologies for stationary external combustion boilers are reviewed. The technologies can be separated into two major groups:

1. Reducing pollutant emissions by boiler modification (i.e., low excess air burner design), and
2. Converting NO_x in the exhaust gas by add-on flue gas treatment devices.

The discussion of each potential NO_x control technology includes a description of the technology and the potential NO_x emission reduction if the technology is concluded to be technically feasible.

<u>Technologies Involving Boiler Modification</u>

Stationary source NO_x emission control technologies originally were developed for use on large, field-erected electric utility boilers since these boilers are the major source of NO_x emissions. As the NO_x control technologies progress and improve, their applications also are extended to smaller industrial and commercial boilers of less than 500 MMBtu/hr heat input. For Boiler No. 16, the following boiler modification techniques for controlling NO_x formation are applicable: low excess air (LEA) combustion process, low nitrogen oxides (NO_x) burner design, and flue gas recirculation.

Low Excess Air Combustion Process

Formation of NO_x in combustion processes is a result of both oxidation of fuel-bound nitrogen and thermal oxidation of molecular nitrogen in the incoming air. The latter oxidation process occurs at a higher temperature condition than the standard fuel-combustion process. Typically, thermal oxidation accounts for more than 50 percent of NO_x formation in an oil-fired combustion process since the concentration of fuel-bound nitrogen is so small. The principal mechanism of NO_x formation from natural gas combustion is also thermal oxidation. Thus, controlling the amount of excess air will have a significant effect on the NO_x thermal oxidation process.

A low excess air (LEA) combustion process can be achieved either by an oxygen sensor and control feedback process or by the burner design. In standard boilers, reduction of the excess air level usually is accomplished by installing a flue gas oxygen sensory unit that provides feedback to an inlet air automatic controller that regulates the excess air at the desired level. The LEA combustion process, by modifying the boiler inlet air condition, can achieve a maximum of 25 percent NO_x reduction.

In modern boilers, the LEA combustion process is engineered as an integral part of the burner design, which allows a minimum air-to-fuel ratio in the thermal combustion zone. The LEA burner design can achieve better excess air reduction than the LEA system with a flue gas oxygen sensor and control feedback mechanism.

Low NO_x Burner Design

Low NO_x burner design can directly incorporate advanced and higher efficiency combustion techniques that result in low NO_x formation. There are two standard low NO_x burner designs: LEA (single-staging) burners and multi-staging combustion burners.

The LEA (single-staging) burners are designed to operate at the lowest level of excess air by way of an efficient combustion process supported by an optimal air-to-fuel mixture. Compared to the operation of conventional burners (in the range of 3 to 6 percent of flue gas oxygen concentration), the LEA burners are capable of operating at stack gas oxygen concentrations of 0.5 to 1.5 percent. LEA burners were reported to achieve 45 percent reduction in NO_x formation over the conventional burner when burning distillate oil. LEA burners typically are applied in single-burner systems because of the difficulty in maintaining equal air distribution in multiple-burner systems.

The multi-staging low NO_x burners are designed with advanced staged-combustion principles to reduce both fuel NO_x and thermal NO_x. The staged-combustion process allows the overall combustion to be carried out in two separate combustion zones. In the air staging combustion process, the burner design allows 70 percent of stoichiometric air to burn in a fuel-rich, primary combustion zone. Some heat generated by this incomplete combustion is transferred to the boiler tubes. The combustion process is primary combustion zone. Because of the heat transfer within the primary combustion zone, the peak combustion temperature is lowered.

The fuel NO_x formation is reduced as a result of the oxygen-starved condition in the fuel-rich primary combustion zone causing the total fixed nitrogen compounds (such as ammonia, hydrogen cyanide, and hydromonoxide) to form inert molecular nitrogen. The thermal NO_x formation also is reduced because the lowered peak temperature in the secondary burnout zone does not provide a sufficient temperature for thermal oxidation of the triple-bond molecular nitrogen. Overall, the multi-staging combustion burners can achieve 30 to 65 percent NO_x emission reduction over conventional burners.

Both LEA (single-staging) and multi-staging low NO_x burners usually are designed with internal flue gas recirculation in order to enhance NO_x emission reduction. In internal flue gas recirculation, combustion air within the burner is recirculated.

Flue Gas Recirculation

Flue gas recirculation (FGR) involves recycling a portion of the flue gas from the exhaust gas stream to the windbox of the boiler. Usually, the recycled flue gas is mixed with the inlet combustion air at the windbox before being introduced into the combustion chamber. In FGR, the recycled flue gas mainly serves as a dilutant to lower the overall peak combustion temperature. The heat sink effect occurs in FGR because the particulates in the recycled flue gas absorb some heat form the combustion process. These effects result in reductions of thermal NO_x and have negligible change in fuel NO_x. Therefore, FGR is applied only to low nitrogen-content fuel, such as natural gas or distillate oil.

FGR typically can reduce thermal NO_x by 55 to 65 percent based on 10 to 15 percent flue gas recirculation rates, respectively (Coen, 1991). The recirculation rates are limited to below 15 percent for oil-fired boilers because of burner flame instability and emissions of unburned combustibles. An application of FGR usually requires a low NO_x burner that can be either a LEA burner or a multi-stage low NO_x burner. Actual FGR efficiency depends on the boiler type and burner design.

__Technologies Involving Exhaust Gas Treatment__

In addition to boiler modification technologies, NO_x emissions can be lowered by NO_x reduction reactions by injecting reducing agents (i.e., ammonia or urea) into the flue gas stream. Also, an add-on device can be inserted into the flue gas ductwork to facilitate the NO_x reduction process. A variety of reaction conditions is required depending on the type of reducing agent and catalyst used. For Boiler No. 16, the following add-on NO_x control devices have been identified: the NO_xOUT selective non-catalytic reduction (SNCR) process and selective catalytic reduction (SCR) with ammonia injection.

NO_xOUT SNCR Process

The NO_xOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO_xOUT process, aqueous urea is injected into the flue gas stream within the boiler, ideally within a temperature range of 1,600° F to 1,900° F. In the presence of oxygen, the following reaction occurs:

$$CO(NH_2)_2 + 2NO + \frac{1}{2}O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech offers a number of catalysts capable of expanding the effective temperature range of the reaction to between 1,000° F and 1,950° F. Advantages of the system are as follows:

1. Low capital and operating costs as a result of using urea injection, and

2. The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are as follows:

1. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts, and
2. SO_3, if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

There have been several commercial applications of the NO_xOUT process. These applications have been in California, Louisiana, Tennessee, Texas, and Florida (Osceola and Okeelanta cogeneration facilities). The reductions in NO_x emissions have ranged from 25 percent to 75 percent.

Selective Catalytic Reduction with Ammonia Injection

Engelhard Corporation's discovery in 1957 that ammonia reacts selectively with NO_x in the presence of a catalyst and excess oxygen has led to the commercialization of selective catalytic reduction (SCR) technology for industrial boilers of various sizes. The technology has been well developed and applied in Japan, especially for control of emissions from gas-, oil-, and coal-fired utility boilers. It has been applied domestically on gas turbines, engine generators and natural gas-fired industrial boilers.

SCR catalysts consist of two types: metal oxides and zeolite. In the metal oxides catalytic system, either vanadium or titanium is embedded into a ceramic matrix structure; the zeolite catalysts are ceramic molecular sieves extruded into modules of honeycomb shape. The all-ceramic zeolite catalysts are durable and less susceptible to catalyst masking or poisoning than the noble metal/ceramic base catalysts. All catalysts exhibit advantages and disadvantages in terms of exhaust gas temperatures, ammonia/NO_x ratio, and optimum exhaust gas oxygen concentrations. A common disadvantage for all catalyst systems is the narrow window of temperature between 600° F and 900° F within which the NO_x reduction process takes place (Schorr, 1989; Steuler, 1990; Engelhard, 19901; Johnson-Matthey, 1990). Operating outside this temperature range results in catastrophic harm to the catalyst system. Chemical poisoning occurs at lower temperature conditions, while thermal degradation occurs at higher temperature. Reactivity can only be restored through catalyst replacement.

Catalysts are subject to loss of activity over time. Since the catalyst is the most costly component of the SCR system, applications require servicing and cleaning of catalyst surface every 2,000 to 3,000 hours of operation. The cleaning normally consists of blowing the catalyst surfaces with a compressed air gun or water jet. Most catalyst suppliers guarantee a catalyst of 3 years, assuming certain operating conditions. SCR is capable of potentially achieving 70 to 90 percent NO_x reduction.

4.4.2 SUMMARY OF TECHNICALLY FEASIBLE NO_X CONTROL METHODS

All of the control methods described thus far are considered to be technically feasible. This section examines these control technologies. First, they are ranked according to their total removal effectiveness. Each alternative is then examined with regard to technical issues, environmental effects, energy requirements and impacts, and economic impacts.

This discussion also reviews previous BACT determinations for industrial fired boilers. Summaries of previous BACT determinations for oil-fired and natural gas-fired industrial boilers are presented in Tables 4-6 and 4-7, respectively. This information was obtained from the RACT/BACT/LAER Clearinghouse on EPA's webpage. The types of control equipment from the previous determinations consist of low NO_x Burners, FGR and good combustion practices. The emission limits for the oil-fired boilers range from 0.1 lb/MMBtu to 0.3 lb/MMBtu. The emission limits for the natural gas-fired boilers range from 0.05 lb/MMBtu to 0.14 lb/MMBtu. Okeelanta's proposed NO_x emission limits for Boiler No. 16 of 0.055 lb/MMBtu for natural gas firing and 0.15 lb/MMBtu for oil are at or near to the lowest BACT emission limits previously issued.

Ranking of Feasible NO_x Control Methods

The top-down BACT approach requires the ranking of the NO_x emission control alternatives in terms of achievable emission level. Only control options that result in a greater degree of emission reduction than the proposed control technology need to be considered. For Boiler No. 16, the proposed control technology is a low-NO_x burner with internal FGR and external FGR. The potentially more effective options, in order of removal effectiveness, are as follows: first the application of SCR to the boiler modified with low-NO_x burner and FGR; and second, SNCR with low-NO_x burner and FGR. The BACT top-down hierarchy of the feasible control scenarios is presented in Table 4-8. A baseline condition must be established for BACT ranking and economic analysis purposes. The baseline for Boiler No. 16 is the current actual emission rate of 0.135 lb/MMBtu.

Analysis of SCR

Technical Issues

Technical Issues involved in the use of SCR are the narrowing operating temperature range, the potential damage to the catalyst and downstream equipment, and the ammonium bisulfate formation. A stack gas reheat system would be required to heat the exhaust gases up to the operating temperature of the SCR. This further complicates an already complex operation consisting of SCR components and an ammonia handling system. The use of ammonia as a reagent for the NO_x reduction reactions may allow excess ammonia to form ammonia bisulfate compounds under irregular operating conditions. These compounds can serve as catalyst poisoning agents and also can damage to metal ductwork downstream. Thus, SCR application requires a strict maintenance cleaning every 2,000 to 2,500 hours of operation (Steuler, 1990). Cleaning consists of blowing the catalyst surfaces with a compressed air gun and vacuuming any soot.

Currently, there is no documented information concerning SCR application on industrial boilers of a similar size and source category as Boiler No. 16. No other oil-fired or natural gas-fired boilers undergoing BACT review have been required to use SCR (refer to Table 4-6 and to Table 4-7).

Environmental Effects

The add-on SCR technology will pose other potential adverse environmental impacts, such as accidental spill and release of ammonia, slippage of ammonia by built-in design, and solid waste disposal for the spent catalyst. These issues are described briefly in the following discussion.

The SCR system requires the use of ammonia as reagent to convert to NO_x to molecular nitrogen and water. The main environmental impact centers around the issue of delivery, handling, and storage of ammonia, which poses inherent safety and health risks in the event of accidental releases. In proposing NO_x abatement regulations for stationary gas turbines, California's South Coast Air Quality Management District (SCAQMD) has performed a risk assessment study on spill handling and storage of ammonia. The study has concluded that this aspect of SCR operation realistically could present serious consequences and recommended further consideration of potential impacts and mitigation measures (SCAQMD, 1979). The current practice is to use an aqueous ammonia system (normally between 25 to 29 percent ammonia concentration) at installations locations used in populated areas. However, such practice increases the complexity, the size, and the cost of the ammonia system. Furthermore, ammonia slippage is a normal occurrence during operation of SCR control equipment. NO_x abatement system suppliers generally report an ammonia slippage level of 10 ppm.

Energy Requirements and Impacts

The add-on technology of SCR imposes further energy penalties. The additional energy requirements are caused by a power loss as a result of additional back pressure from the SCR, electrical requirements for heating the ammonia solution and operating the injection system, and additional energy necessary for heating the ammonia solution and operating the injection system, and additional energy necessary for heating the exhaust gases from Boiler No. 16 from

425°F up to the SCR operating range of 700°F. A minimum of 16 MMBtu/hr would be required for stack gas reheating.

Economic Analysis

This section includes the total capital investment (TCI) and the annualized cost (AC) for SCR applied to Boiler No. 16. All cost values are calculated from vendor quotes or standard costing procedures based on the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual, Fifth Edition (OAQPS, 1996).

In this costing procedure, the basic equipment cost is the basis for other itemized costs that are calculated as fractional costs of the basic equipment cost. The capital cost estimates, the annualized cost estimates, and the cost effectiveness for SCR are presented in Table 4-9. The basic equipment cost for the SCR was obtained from a vendor for a previous BACT review for Boiler No. 16.

For SCR applied to the proposed modified Boiler No. 16, with low-NO_x burners, the TCI is $2.8 million; the annualized cost is $686,807 and the cost effectiveness is $7,546 per ton of NO_x removed.

__Analysis of SNCR__

Technical Issues

The SNCR process operates best at temperatures of 1,000°F to 1,950°F. The exhaust temperature of Boiler No. 16 is approximately 425°F. Modifications to the process such as injectors can be used to inject the reagent at the ideal location in the furnace.

Environmental Effects

Since a liquid urea reagent is injected into the boiler, there is a chance of spilling the reagent during transport or storage of the reagent. Although the reagent is not listed as a hazardous substance, the vapors from the reagent can cause respiratory, skin and eye irritation when someone is exposed to them long enough.

Energy Requirements

SNCR requires additional energy. For Boiler No. 16, the NO_xOUT SNCR process would consume between 15 and 20 kilowatts of electricity.

Economic Analysis

This section includes the TCI and the AC for the SNCR process applied to Boiler No. 16. All cost values are calculated from vendor quotes and standard costing procedures based on the OAQPS Control Cost Manual, Fifth Edition (OAQPS, 1996).

In this costing procedure, the basic equipment cost is the basis for other itemized costs that are calculated as fractional costs of the basic equipment cost. The capital cost estimates, the annualized cost estimates, and the cost effectiveness for SNCR are presented in Table 4-10. The basic equipment cost for the SNCR was obtained from a vendor. For the SNCR process, the TCI is $950,000; the annualized cost is $282,011 and the cost effectiveness is $8,263 per ton of NO_x removed.

4.4.3 NO_x BACT SUMMARY AND CONCLUSION

The BACT analysis for NO_x control has identified two feasible control alternatives that achieve greater reduction than low-NO_x burners with FGR alone: ceramic-based SCR and SNCR. This section will consider the overall environmental, energy, and economic impacts of each alternative and eliminate those with adverse impacts. The control alternative not eliminated will be selected as BACT.

<u>Comparison of Technical Issues</u>

Compared to the two alternatives, the low NO_x burner design with FGR is the most reliable option overall for industrial boiler application. Add-on control technology such as SCR application and SNCR application on the modified boiler will further complicate the entire boiler operation. These potential complications are a result of significant routine maintenance and unscheduled downtime because of malfunction or failure of components.

Comparison of Environmental Effects

The add-on control technology options pose the greatest potential for environmental impacts. SCR poses the greatest potential for toxic impacts as a result of ammonia handling and storage, and ammonia slip. Although the reagents used in the NO_xOut SNCR process is not a listed toxic, there is still a risk for spills and leaks. The boiler modifications do not have any adverse environmental effects. Therefore, the boiler modification process involving both LNB and FGR is the best NO_x control technology for Boiler No. 16 in regard to the environmental effects.

Comparisons of Energy Impacts

The options involving add-on control technology require additional fuel and energy. The low-NO_x burner option does not require additional fuel or electricity to operate. Therefore, the boiler modification process using the LNB/FGR option is the best NO_x control technology with regard to energy impacts.

Comparison of Economic Analysis

The add-on control technology options involve significant TCI and high cost effectiveness for removal of NO_x. The cost effectiveness of the SCR option is $7,546 and the cost effectiveness of the SNCR option is $8,263. The high cost effectiveness of these options deem the add-on control technology options economically infeasible. Therefore, the LNB/FGR option is the best NO_x control technology with regard to economic impacts.

Conclusion

The NO_x top-down BACT analysis in terms of environmental impacts, energy impacts, and economical impacts for Boiler No. 16 is summarized in Table 4-11. The analysis has included two add-on control technologies. The main reasons for eliminating both SCR and SNCR are their high cost effectiveness. This is consistent with previous BACT determinations for NO_x emissions from industrial boilers. There are no existing industrial boilers that have been required to use SCR or SNCR for NO_x control (refer to Tables 4-6 and 4-7). By eliminating both add-on control technology options, the LNB with FGR option is concluded to be BACT for NO_x emissions from Boiler No. 16.

4.5 BACT DETERMINATION FOR CO EMISSIONS

Maximum CO emissions from Boiler No. 16 are estimated to be 140.90 TPY. Okeelanta proposes to use good combustion practices to control CO emissions.

As part of the BACT analysis, a review of previous CO BACT determinations for industrial boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's webpage was performed. Summaries of the BACT determinations for both fuel oil- and natural gas-fired boilers from this review are presented in Tables 4-12 and 4-13, respectively. The CO emission limits for fuel oil-fired boilers range from 0.04 lb/MMBtu to 0.17 lb/MMBtu. The CO emission limits for natural gas-fired boilers range from 0.04 lb/MMBtu to 0.20 lb/MMBtu. This rather large range of emissions is due to differences in boiler design and operation. From the review of previous BACT determinations, it is evident that CO BACT determinations for both oil-fired and natural gas-fired industrial boilers have typically been good combustion practices and boiler design.

Proposed maximum CO emissions from Boiler No. 16 are 0.15 lb/MMBtu for natural gas firing and 0.16 lb/MMBtu for fuel oil firing. These emission limits are with in the range of previous determinations, and are based on vendor information. Boiler No. 16 is a "narrow" boiler. As a result, the horizontal spread of the flame is limited, which in turn affects air/fuel mixing and places limitations on the burner design. For this reason, the CO emissions cannot be reduced any further through burner design.

No other gas/oil fired boilers have been required to use add-on control for CO emissions from Boiler No. 16. Okeelanta proposes to use good combustion practices to control CO emissions from Boiler No. 16. This level of control is consistent with previous determinations.

Table 4-1. BACT Determinations for SO_2 Emissions for Fuel Oil-Fired Industrial Boilers

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits As Provided In LAER/BACT Clearinghouse	Control Equipment/Description
Proctor and Gamble Manufacturing Company	TN	TN-0054	3/19/98	--	37.96 lb/hr	--
Appleton Paper, Inc.	WI	WI-0065	1/12/93	200,000 lbs steam/hr	0.507 lb/MMBtu	--
Okeelanta Corporation	FL	FL-0048	7/29/91	205 MMBtu/hr	0.51 lb/MMBtu	Fuel Spec: Limit Fuel Sulfur Content

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2000

Table 4-2. BACT Determinations for SO_2 Emissions for Natural Gas-Fired Industrial Boilers, 100 MMBtu/hr or Greater

Company	State	RBLC ID	Permit Date	Heat Input	Emissions: As Provided In LAER/BACT Clearinghouse	Emissions: Converted to lb/MMBtu [a]	Control Equipment/Description
Texasgulf Soda Ash Plant	WY	WY-0035	10/13/97	431.6 MMBtu/hr	Negligible	--	Natural Gas Fuel
Weyerhaeuser Company	MS	MS-0029	9/10/96	400 MMBtu/hr	5.7 E-4 lb/MMBtu	0.00057	Use of Natural Gas as Fuel
Transamerican Refining Corporation	LA	LA-0090	2/10/95	244 MMBtu/hr	6.6 lb/hr	0.03	Fuel Specification
Newark Bay Cogeneration Partnership, L.P.	NJ	NJ-0017	6/9/93	200 MMBtu/hr	0.0026 lb/MMBtu	0.0026	Fuel Spec: Natural Gas
Willamette Industries Inc.	LA	LA-0074	2/4/91	335 MMBtu/hr	0.2 lb/hr	0.0006	Fuel Spec: Low Sulfur Fuel

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2000

Footnotes:

[a] To convert from lb/hr, the emission limit was divided by the heat input rate.

Table 4-3. BACT Determinations for PM/PM_{10} Emissions for Fuel Oil-Fired Industrial Boilers

Company	State	RBLC ID	Permit Date	Throughput	Emissions: As Provided In LAER/BACT Clearinghouse	Emissions: Converted to lb/MMBtu [a]	Control Equipment/Description
Toyota Motor Manufacturing U.S.A. Inc.	KY	KY-0052	7/17/86	0	0.05 lb/MMBtu	0.05	--
McCaine Food Inc.	ME	ME-0017	3/12/99	656.7 gal/hr	0.08 lb/MMBtu	0.08	0.5 % Sulfur Fuel Oil

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2000

Footnotes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate.

Table 4-4. BACT Determinations for PM/PM_{10} Emissions for Natural Gas-Fired Industrial Boilers, 100 MMBtu/hr or Greater

Company	State	RBLC ID	Permit Date	Throughput	Emissions: As Provided In LAER/BACT Clearinghouse	Emissions: Converted to lb/MMBtu [a]	Control Equipment/Description
Cargill Inc. - Sioux City	IA	IA-0048	6/1/98	4500 TPD	0.7 lb/hr	--	500 hr/yr Restriction
Chevron Chemical Company	LA	LA-0114	12/10/97	600 MMBtu/hr	0.025 lb/MMBtu	0.025	Good Design and Operation
Texasgulf Soda Ash Plant	WY	WY-0035	10/13/97	431.6 MMBtu/hr	0 NEGLIGIBLE	--	Natural Gas Fuel
Grain Processing Corp.	IN	IN-0075	6/10/97	244 MMBtu/hr	5 lb/MMCF	0.005	--
Westlake Petrochemicals Corporation	LA	LA-0100	1/18/96	215 MMBtu/hr	1.8 TPY	0.002	Good Design, Proper Operating Practices, Clean Fuels
Transamerican Refining Corporation	LA	LA-0090	2/10/95	244 MMBtu/hr	1.2 lb/hr	0.005	Fuel Specification
Newark Bay Cogeneration Partnership, L.P.	NJ	NJ-0017	6/9/93	200 MMBtu/hr	0.005 lb/MMBtu	0.005	Boiler Design/FGR
					AVERAGE	0.01	
					MAXIMUM	0.03	
					MINIMUM	0.002	

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2000

Footnotes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate. To convert from lb/MMCF, the emission limit was divided by 1,020 MMCF/MMBtu.

Table 4-5. Emission Test Results for Boiler No. 16, Okeelanta Corporation

Test Date	Run Number	PM Emissions (lb/hr)	PM Emissions (lb/MMBtu)	NO_x Emissions (lb/hr)	NO_x Emissions (lb/MMBtu)
7/14/94	1	1.53	0.010	27.83	0.174
	2	1.62	0.009	28.38	0.159
	3	0.99	0.005	28.08	0.144
	Average	**1.38**	**0.008**	**28.10**	**0.159**
8/4/94	1	1.69	0.009	24.34	0.123
	2	0.86	0.004	23.95	0.118
	3	1.31	0.007	24.58	0.131
	Average	**1.29**	**0.007**	**24.29**	**0.124**
8/3/95	1	2.03	0.011	22.82	0.119
	2	0.72	0.004	25.34	0.131
	3	0.92	0.005	27.30	0.135
	Average	**1.22**	**0.007**	**25.15**	**0.128**
6/5/96	1	1.26	0.006	25.63	0.126
	2	3.73	0.017	28.53	0.134
	3	3.73	0.017	28.10	0.130
	Average	**2.91**	**0.013**	**27.42**	**0.130**
7/23/97	1	4.98	0.025	24.13	0.122
	2	2.84	0.010	23.95	0.125
	3	2.28	0.008	24.55	0.127
	Average	**3.37**	**0.014**	**24.21**	**0.125**
8/4/98	1	5.57	0.032	24.13	0.140
	2	4.95	0.029	24.41	0.141
	3	3.91	0.024	23.69	0.144
	Average	**4.81**	**0.028**	**24.08**	**0.142**
1/14/1999 (a)	1	--	--	--	0.134
	2	--	--	--	0.135
	3	--	--	--	0.142
	4	--	--	--	0.143
	5	--	--	--	0.142
	6	--	--	--	0.142
	7	--	--	--	0.141
	8	--	--	--	0.140
	9	--	--	--	0.140
	Average	**--**	**--**	**--**	**0.140**
AVERAGE OF TESTS (b)		**2.50**	**0.013**	**25.54**	**0.135**

References: Source Test Reports for Boiler No. 16 conducted by Air Consulting and Engineering, Inc.

Notes:

(a) Emissions are from the Relative Accuracy Test Audit of the NOx CEMS system.
(b) Calculated by taking the average of the average test results.

Table 4-6. BACT Determinations for NO_x Emissions for Fuel Oil-Fired Industrial Boilers

Company	State	RBLC ID	Permit Date	Throughput	Emissions: As Provided In LAER/BACT Clearinghouse	Emissions: Converted to lb/MMBtu [a]	Control Equipment/Description	% Efficiency
McCaine Food Inc.	ME	ME-0017	3/12/99	656.7 gal/hr	0.3 lb/MMBtu	0.3	Low NOx Burners, Staged Air, Flue Gas Recirculation	--
Piney Point Phosphates, Inc.	FL	FL-0090	9/23/94	190 MMBtu/hr	28.5 lb/hr	0.15	Low NOx Burners, EGR	--
Appleton Paper, Inc.	WI	WI-0065	1/12/93	200000 lbs steam/hr	0.1 lb/MMBtu	0.1	Low NOx Burners and Flue Gas Reinductor	75
Okeelanta Corporation	FL	FL-0048	7/29/91	205 MMBtu/hr	0.18 lb/MMBtu	0.18	Combustion Control	--
					AVERAGE	0.18		
					MAXIMUM	0.3		
					MINIMUM	0.1		

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2000

Footnotes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate.

Table 4-7. BACT Determinations for NO_x Emissions for Natural Gas-Fired Industrial Boilers, 100 MMBtu/hr or Greater

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits: As Provided In LAER/BACT Clearinghouse	Emission Limits: Converted to lb/MMBtu [a]	Control Equipment/Description	% Efficiency
Archer Daniels Midland Company	IL	IL-0060	12/24/98	350 MMBtu/hr	0.05 lb/MMBtu	0.05	Low-NOx Burners; Fuel Selection	--
Alliant Energy	IA	IA-0045	5/29/98	278 MMBtu/hr	0.1 lb/MMBtu	0.1	Low NOx Burner with Steam Injection	--
Chevron Chemical Company	LA	LA-0114	12/10/97	600 MMBtu/hr	0.141 lb/MMBtu	0.141	Ultra Low NOx Burners and FGR	--
Bucknell University	PA	PA-0149	11/26/97	24000 lb/hr steam	0.1 lb/MMBtu	0.1	--	--
Shell Chemical Company	LA	LA-0115	11/3/97	300 MMBtu/hr	0.05 lb/MMBtu	0.05	Low NOx Burner and internal FGR	--
Texasgulf Soda Ash Plant	WY	WY-0035	10/13/97	431.6 MMBtu/hr	0.05 lb/MMBtu	0.05	Low NOx Burners with 16% FGR	--
Grain Processing Corp.	IN	IN-0075	6/10/97	244 MMBtu/hr	0.05 lb/MMBtu	0.05	Low NOx Burners and FGR	--
Quincy Soybean Company of Arkansas	AR	AR-0019	3/4/97	123 MMBtu/hr	0.05 lb/MMBtu	0.05	Low NOx Combustors	--
IMC-Agrico Company - Faustina Plant	LA	LA-0105	10/16/96	320 MMBtu/hr	0.08 lb/MMBtu	0.08	Low NOx Burners	--
Weyerhaeuser Company	MS	MS-0029	9/10/96	400 MMBtu/hr	0.1 lb/MMBtu	0.1	Low NOx Burners and FGR	--
Star Enterprise - Louisiana Plant Refinery	LA	LA-0102	7/29/96	570 MMBtu/hr	0.08 lb/MMBtu	0.08	Low NOx Burners (Staged Combustion, Staged Fuel)	--
Transamerican Refining Corporation	LA	LA-0090	2/10/95	244 MMBtu/hr	19.8 lb/hr	0.08	Low NOx Burners/Combustion Control	--
Archer Daniels Midland Company	IL	IL-0058	8/11/94	350 MMBtu/hr	0.05 lb/MMBtu	0.05	Low NOx Burners; Fuel Selection	--
Champion International Corp.	FL	FL-0087	3/25/94	533 MMBtu/hr	0.06 lb/MMBtu	0.06	COEN Low NOx Burners and FGR	--
FMC WY Corporation - Green River Soda Ash Plant	WY	WY-0028	9/7/93	234 MMBtu/hr	0.1 lb/MMBtu	0.1	Low NOx Burners with Low Excess Air and FGR	--
SF Phosphate Limited Company	WY	WY-0043	7/2/93	350 MMBtu/hr	0.14 lb/MMBtu	0.14	Low NOx Burners	--
SF Phosphate Limited Company	WY	WY-0043	7/2/93	350 MMBtu/hr	0.14 lb/MMBtu	0.14	Low NOx Burners	--
Newark Bay Cogeneration Partnership, L.P.	NJ	NJ-0017	6/9/93	200 MMBtu/hr	0.05 lb/MMBtu	0.05	Low NOx Burners, FGR	--
American Crystal Sugar Company	MN	MN-0019	12/15/92	200.1 MMBtu/hr	0.075 lb/MMBtu	0.075	Low NOx Burner with FGR Boiler Installation	--
CPC - Corn Products Division	IL	IL-0044	8/6/92	600 MMBtu/hr	0.05 lb/MMBtu	0.05	Low NOx Burner and FGR	85
					AVERAGE	0.08		
					MAXIMUM	0.14		
					MINIMUM	0.05		

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2000
FGR = Flue Gas Recirculation

Footnotes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate. To convert from TPY, the emission limit was converted into lb/hr by assuming 8,760 hours of operation and then divided by the throughput rate.

Table 4-8. BACT "Top-down" Hierarchy of NO_x Reduction Methods for Boiler No. 16

Top-Down Ranking	Technology	Control Effectiveness (%)	Emission Level (lb/MMBtu)	Annual Emissions (TPY)
First	Low-NO_x burner with SCR	92[a]	0.030	22.8
Second	Low-NO_x burner with SNCR	72[b]	0.105	79.6
Third	Low-NO_x burner with FGR	60	0.15[c]	113.8 [e]
Current	Existing Boiler No. 16	--	0.135[d]	121.2

Footnotes:

[a] SCR alone can achieve 80 percent reduction.

[b] SNCR alone can achieve 30 percent reduction.

[c] Proposed Boiler No. 16 emission rate for fuel-oil firing.

[d] Based on actual average emissions from Boiler No. 16 firing distillate oil.

[e] Based on an emission rate of 0.11 lb/MMBtu for fuel oil-firing at 202 MMBtu/hr for 6,733 hours and an emission rate of 0.055 lb/MMBtu for natural gas at 211 MMBtu/hr for 2,027 hours.

Table 4-9. Cost Effectiveness of SCR, Okeelanta Boiler No. 16

Cost Items	Cost Factors[a]	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
SCR Basic Process	Vendor quote[b]	1,400,000
Ammonia System	See note "c"	36,560
Auxilary Equipment (Reheat)	10% of equipment cost	140,000
Emissions Monitoring	15% of equipment cost	140,000
Structure Support	8% of equipment cost	112,000
Freight	5% of equipment cost	70,000
Taxes	Florida sales tax, 6%	84,000
Total PEC:		1,982,560
Direct Installation	30% of PEC	594,768
Total DCC:		2,577,328
INDIRECT CAPITAL COSTS (ICC):		
Engineering	10% of PEC	257,733
Construction and field expenses	5% of PEC	128,866
Contractor Fees	10% of PEC	257,733
Startup	2% of PEC	51,547
Performance test	1% of PEC	25,773
Contingencies	3% of PEC	77,320
Total DCC:		798,972
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	2,781,532
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	0.5 hr/shift, $16/hr, 8760 hrs/yr	8,760
Supervisor	15% of operator cost	1,314
(2) Maintenance	Vendor quote	10,000
(3) Variable O&M[d,e]	211 MMBtu/hr; 8,760 hr/yr	44,300
(4) Catalyst Replacement and disposal[e]	211 MMBtu/hr; 8,760 hr/yr; 3 year life	104,150
Total DOC:		168,524
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	12,044
Property Taxes	1% of total capital investment	27,815
Insurance	1% of total capital investment	27,815
Administration	2% of total capital investment	55,631
Total IOC:		123,306
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.142 times TCI (10 yrs @ 7%)	394,977
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	686,807
BASELINE NO_x EMISSIONS (TPY):	0.15 lb/MMBtu; 202 MMBtu/hr; 6,733 hr/yr (fuel oil) and 0.055 lb/MMBtu, 211 MMBtu/hr, 2,027 hr/yr (natural gas)	113.8
MAXIMUM NO_x EMISSIONS (TPY):	80% reduction	22.8
REDUCTION IN NO_x EMISSONS (TPY):		91.0
COST EFFECTIVENESS:	$ per ton of NO_x Removed	7,546

Footnotes

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 3, Fifth edition. Cost estimates have been converted from 1988 dollars to 1999 dollars by a ratio of CE Cost Indexes (1988: 342.5, 1999: 400).

[b] Vendor quote from 1991 quote for SCR system for Boiler No. 16. Quote has been converted from 1991 dollars to 1999 dollars by a ratio of CE Cost Indexes (1991: 361.3, 1999: 400)

[c] Ammonia vendor's quotation for LaRoche Industries, Inc. for a 3,000-gallon anhydrous ammonia tank, an ammonia evaporator, and a dual-valve pressure regulator. Quote was converted to 1999 dollars from 1991 dollars by a ratio of CE Cost Indexes (1991: 361.3 and 1999: 400).

[d] Includes cost of ammonia, electricity and steam.

[e] Based on cost equation and factors from the EPA document titled "New Source Performance Standards, Subpart Db - Technical Support for Proposed Revisions to NOx Standard" (6/97). See Appendix A for equation and factors.

Table 4-10. Cost Effectiveness of SNCR, Okeelanta Boiler No. 16

Cost Items	Cost Factors[a]	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
SNCR Process Equipment	Vendor quote	750,000
Freight	Vendor quote	20,000
Taxes	Florida sales tax, 6%	45,000
Total PEC:		815,000
Direct Installation Cost		
Foundation and Supports	8% of SNCR Process Equipment Cost	60,000
Electrical	4% of SNCR Process Equipment Cost	30,000
Piping	2% of SNCR Process Equipment Cost	15,000
Total Direct Installation Cost:		105,000
Total DCC		920,000
INDIRECT CAPITAL COSTS (ICC):		
Engineering		Included Above
Startup		Included Above
Performance Tests	1% of SNCR Process Equipment Cost	7,500
Contingency	3% of SNCR Process Equipment Cost	22,500
Total ICC		30,000
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	950,000
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	0.5 hr/shift, $15/hr, 8760 hrs/yr	8,213
Supervisor	15% of operator cost	1,232
(2) Maintenance	Vendor quote	15,000
(3) Electricity	Vendor quote	25,000
(4) Reagent (Urea)	Vendor quote	45,000
Total DOC:		94,444
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	14,667
Property Taxes	1% of total capital investment	9,500
Insurance	1% of total capital investment	9,500
Administration	2% of total capital investment	19,000
Total IOC:		52,667
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.142 times TCI (10 yrs @ 7%)	134,900
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	282,011
BASELINE NO_x EMISSIONS (TPY) :	0.15 lb/MMBtu; 202 MMBtu/hr; 6,733 hr/yr (fuel oil) and 0.055 lb/MMBtu, 211 MMBtu/hr; 2,027 hr/yr (natural gas)	113.8
MAXIMUM NO_x EMISSIONS (TPY) :	30% reduction	79.6
REDUCTION IN NO_x EMISSONS (TPY):		34.1
COST EFFECTIVENESS:	$ per ton of NO_x Removed	8,263

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 3, Fifth edition.

Table 4-11. Summary of Top-Down BACT Impact Analysis Results for NO_x

Control Alternative	Total Emission Reduction (TPY)	Potential Environmental Impacts		Energy Impacts: Incremental Increase Over Baseline?		Economic Impacts	
		Toxic Air Impact?	Adverse Environmental Impacts?	Fuel	Electricity	Annualized Cost ($)	Cost Effectiveness ($/ton)
Low-NO_x burner with SCR	91.0	Yes	Yes	Yes	Yes	686,807	7,546
Low-NO_x burner with SNCR	34.1	No	Yes	Yes	Yes	282,011	8,263
Low-NO_x burner with FGR	--	No	No	No	No	--	--
Existing Boiler No. 16	--	--	--	--	--	--	--

Table 4-12. BACT Determinations for CO Emissions for Fuel Oil-Fired Boilers, 100 - 250 MMBtu/hr

Company	State	RBLC ID	Permit Date	Throughput	Emissions: As Provided In LAER/BACT Clearinghouse	Emissions: Converted to lb/MMBtu [a]	Control Equipment/ Description
Lakewood Cogeneration, L.P.	NJ	NJ-0013	4/1/91	131 MMBtu/hr	0.17 lb/MMBtu	0.17	Boiler Design
Old Dominion Electric Cooperative	VA	VA-0181	4/29/91	213.9 MMBtu/hr	0.16 lb/MMBtu	0.16	Operating hours
South Carolina Electric and Gas Company	SC	SC-0027	7/15/92	190.35 MMBtu/hr	6.8 lb/hr	0.04	--
					AVERAGE	0.12	
					MAXIMUM	0.17	
					MINIMUM	0.04	

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2000

Footnotes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate.

[b] Based on a 30 day average.

Table 4-13. BACT Determinations for CO Emissions for Natural Gas-Fired Boilers, 100 - 250 MMBtu/hr

Company	State	RBLC ID	Permit Date	Throughput	Emissions: As Provided In LAER/ BACT Clearinghouse	Emissions: Converted to lb/MMBtu [a]	Control Equipment/Description
Quincy Soybean Company of Arkansas	AR	AR-0019	3/4/97	123 MMBtu/hr	24.6 lb/hr	0.2	Good combustion practices
Alabama Power Company - Theodore Cogeneration	AL	AL-0128	3/16/99	220 MMBtu/hr	0.165 lb/MMBtu	0.165	Efficient combustion
Pilgrim Energy Center	NY	NY-0075		204 MMBtu/hr	0.16 lb/MMBtu	0.16	--
Lockport Cogen Facility	NY	NY-0073	7/14/93	210 MMBtu/hr	0.13 lb/MMBtu	0.13	No controls
Saranac Energy Company	NY	NY-0046	7/31/92	249 MMBtu/hr	0.118 lb/MMBtu	0.118	Combustion control
James River Corp.	MI	MI-0202	9/17/91	226.7 MMBtu/hr	0.09 lb/MMBtu	0.09	--
Anitec Cogen Plant	NY	NY-0061	7/7/93	123 MMBtu/hr	0.08 lb/MMBtu	0.08	No controls
Lakewood Cogeneration, L.P.	NJ	NJ-0013	4/1/91	131 MMBtu/hr	0.042 lb/MMBtu	0.042	Boiler design
Transamerican Refining Corporation	LA	LA-0090	2/10/95	244 MMBtu/hr	9.8 lb/hr	0.04	Combustion control
FMC WY Corporation - Green River Soda Ash Plant	WY	WY-0028	9/7/93	234 MMBtu/hr	9.36 lb/hr	0.04	Low NO_x burners with LEA and FGR
Grain Processing Corp.	IN	IN-0075	6/10/97	244 MMBtu/hr	0.04 lb/MMBtu	0.04	Good combustion control
Newsprint South, Inc.	MS	MS-0014	8/8/89	227.4 MMBtu/hr	0.04 lb/MMBtu	0.04	Operation control, boiler design
Newsprint South, Inc.	MS	MS-0014	8/8/89	176.5 MMBtu/hr	0.04 lb/MMBtu	0.04	Boiler design and good combustion practices
					AVERAGE	0.09	
					MAXIMUM	0.20	
					MINIMUM	0.04	

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2000

Footnotes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate.

5.0 AIR QUALITY IMPACT ANALYSIS

For the proposed project, the net emissions changes are greater than the PSD significant emission rates for NO_x and PM_{10}. As a result, an air quality impact analysis is required for these pollutants under the new source review procedures in the FDEP PSD regulations. The following section presents the air modeling approach, including methods and assumptions, and summaries of maximum pollutant concentrations predicted for comparison to AAQS and PSD increments.

5.1 AIR MODELING ANALYSIS APPROACH

5.1.1 MODEL SELECTIONS

Significant Impact Analysis

The ISCST3 dispersion model (Version 10100) was used to evaluate the pollutant impacts due to Boiler No. 16 alone. This model is currently available on the EPA's Internet web site, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). A listing of ISCST3 model features is presented in Table 5-1. The ISCST3 model is designed to calculate hourly concentrations based on hourly meteorological data (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The ISCST3 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. These areas are referred to as simple terrain. The model can also be applied in areas where the terrain exceeds the stack heights. These areas are referred to as complex terrain.

Since the terrain surrounding the Okeelanta facility is flat, the modeling analysis assumed that all receptors were at the base elevation of the facility (i.e., flat terrain assumption in ISCST3).

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The ISCST3 model can run in the rural or urban land use mode, which affects stability dispersion coefficients, wind speed profiles, and mixing heights. Land use can be characterized based on a scheme recommended by EPA (Auer, 1978). If more than 50 percent of the land use within a 3-km radius circle around a project is classified as industrial or commercial, or high-density residential, then the urban option should be selected. Otherwise, the rural option is appropriate. Based on reviews of aerial and U.S. Geological Survey (USGS) topographical maps and a site visit, the land use within a 3-km (1.9-mile) radius of the Okeelanta site is considered to be rural (i.e., very little heavy industrial, light-moderate industrial, commercial, or compact residential land use categories). Therefore, the rural mode was used in the air dispersion model to predict impacts from the Okeelanta site.

The ISCST3 model was used to predict maximum pollutant concentrations for averaging the annual and 24-hour, 8-hour, 3-hour, and 1-hour averaging periods. The predicted concentrations were then compared to applicable significant impact levels (SIL), allowable PSD increments, or to the AAQS that exist for the same respective averaging times.

PSD CLASS I

The California Puff (CALPUFF, Version 5.4) air dispersion model was used to model the PSD Class I impacts of Boiler No. 16 at the ENP. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport (LRT) model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model, a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters.

CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET was input to CALPUFF to assess the pollutant specific impact. Both CALMET and CALPUFF were used in a manner that is recommended by the IWAQM Phase 2 Report.

The CALPUFF settings contained in Table 5-2 were used for the PSD Class I significant impact analysis. A detailed listing of parameter values used is presented in Table B-1, Appendix B.

5.1.2 SIGNIFICANT IMPACT ANALYSIS

<u>Site Vicinity</u>

A significant impact analysis is performed for all criteria pollutants that are emitted in amounts greater than the applicable PSD significant emission rates. For each pollutant, a significant impact analysis is performed to determine a project's maximum air quality impact and the distance at which the project's impacts are below SIL. If the project's maximum impacts are less than the SIL, no additional modeling with other sources is needed and the impact analysis is complete. However, if the project's impacts are predicted to be greater than the SIL for a particular pollutant, then additional, more detailed modeling analyses are required for that pollutant. The additional analyses include AAQS and PSD increment analyses. Both of these detailed analyses require that the cumulative air quality impacts from other facilities that are in the vicinity of the proposed project's plant be addressed in the impact evaluation. A more detailed description of these analyses is provided in the following sections.

<u>PSD Class I Areas</u>

If the project is within 200 km of a PSD Class I area, then a significant impact analysis is also performed at the PSD Class I area. Currently, the EPA has proposed SIL for PSD Class I areas. If the project's impacts are above the SIL, then a more detailed air modeling analysis is performed with PSD increment consuming and expanding background facilities to determine increment consumption at the PSD Class I area.

Because the Okeelanta facility is located approximately 92 km from the Everglades National Park (ENP), a PSD Class I area, a significant impact analysis was conducted at the ENP. Current FDEP policies stipulate that the highest annual average and highest short-term (i.e., 24 hours or less) concentrations are to be compared to the applicable SIL.

5.1.3 AAQS/PSD INCREMENT ANALYSES

AAQS and PSD Class II Increment Analyses

For all pollutants that have a significant impact, a more detailed impact analysis is required. In general, when 5 years of meteorological data are used, the highest annual and the highest, second-highest (H2H) short-term concentrations are to be compared to the applicable AAQS and allowable PSD Class II increments. The H2H is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

This approach is consistent with most air quality standards and all allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor.

For the AAQS analysis, the future emissions of the plant site are modeled with background emission facilities. A non-modeled background concentration is added to the maximum predicted air quality to determine a total air quality concentration. The maximum annual and H2H short-term total concentrations are compared to the AAQS.

For the PSD Class II increment analysis, the PSD increment consuming and expanding sources at the ASA site are modeled with background PSD consuming or expanding sources. The maximum annual and H2H short-term PSD increment are compared to the allowable PSD Class II increments.

PSD Class I Increment Analysis

For all pollutants that have a significant impact at the PSD Class I area, a more detailed PSD increment analysis is required at the PSD Class I area. For the PSD Class I increment analysis, the PSD increment consuming and expanding sources at the Okeelanta site are modeled with other background PSD consuming or expanding sources within 200 miles from the PSD Class I area. The maximum annual and H2H short-term PSD increments are compared to the allowable PSD Class I increments.

5.1.4 METEOROLOGICAL DATA

<u>Significant Impact Analysis</u>

Meteorological data used in the ISCST3 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) office located at the Palm Beach International Airport (PBI). Concentrations were predicted using 5 years of hourly meteorological data from 1987 through 1991. The NWS office at PBI is located approximately 64 km east of the site and is the closest primary weather station to the study area considered to have meteorological data representative of the project site. The PBI station meteorological data have been approved by the FDEP and used for numerous air modeling studies submitted as part of air construction permits approved for sources located in Palm Beach County.

In the ISCST3 model, the wind speeds are adjusted from the height at which they are measured (i.e., anemometer height) to the height of each stack considered in the analysis. In this analysis, an anemometer height of 33 ft is used for the modeling analysis.

The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling height. The wind speed, cloud cover, and cloud ceiling values were used in the ISCST3 meteorological preprocessor program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated from the radiosonde data at Ruskin using the Holzworth approach (Holzworth, 1972). Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by EPA (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential, hourly meteorological data set (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions at the NWS stations are classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed using the EPA RAMMET meteorological preprocessor program.

<u>PSD Class I</u>

The California Puff meteorological and geophysical data preprocessor (CALMET, Version 5.4) was used to develop the gridded parameter fields required for the PSD Class I significant impact modeling analysis. The follow sections discuss the specific data used and processed in the CALMET model.

CALMET Settings

The CALMET settings contained in Table 5-3 were used for the refined modeling analysis. A summary of parameter values used is presented in Table B-2, Appendix B.

Modeling Domain

The modeling domain defines the boundary of plume simulation area. The modeling domain used for the analysis is in the shape of a rectangle extending approximately 450 km in the east-west (x) direction and 470 km in the north-south (y) direction. The southwest corner of the rectangle is the origin of the modeling domain and is located at 23.75 N degrees latitude and 83.5 W degrees longitude.

For the processing of meteorological and geophysical data, 90 grid cells were used in the x-direction and 94 grid cells were used in the y-direction. A grid resolution of 5 km was used. The air modeling analysis was performed with the UTM coordinate system.

Mesoscale Model – Generation 4 (MM4) Data

Pennsylvania State University in conjunction with the NCAR Assessment Laboratory developed the MM4 data, a prognostic wind field or "guess" field, for the United States (U.S.). The hourly meteorological variables used to create this data set (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and only allow for one data base set for the year 1990. The analysis used the MM4 data to initialize the CALMET wind field. The MM4 data have a horizontal spacing of 80 km and are used to simulate atmospheric variables within the modeling domain.

To apply the MM4 dataset to a regional modeling domain, such as the area that will incorporate Okeelanta facility and the ENP, a sub-set domain was developed based on the MM4 data local coordinate system. In this coordinate system, the subset domain consisted of a 8 x 8- cell rectangle, spaced at 80 km, extending from MM4 coordinates (45,13) to (52,18). These data were processed to create a MM4.Dat file, which was input to the CALMET model.

The MM4 data set used in the CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables were processed into the appropriate format and introduced into the CALMET model through the additional data files obtained from the following sources.

Surface Data Stations and Processing

The processed surface data includes the following eight primary weather stations that are located either within or just beyond the modeling domain. The eight surface stations include Orlando, Fort Myers, Vero Beach, Miami, Daytona Beach, Key West, West Palm Beach and Tampa in Florida. The parameters included for these stations are wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure and a precipitation code that is based on current weather conditions. The weather station data for all stations were extracted for the year 1990 from the National Climatic Data Center's (NCDC) Solar and Meteorological Surface Observational Network (SAMSON) CD. All data were processed with the CALMET preprocessor utility program, SMERGE, to create the SURF.DAT file for input to CALMET. Because the air modeling domain extends into the Gulf of Mexico, surface observations from Sombrero Key, Lake Worth, and Venice stations in Florida were included in the analysis. The data from these stations were converted into overwater surface station formats (i.e., SEA) for input to CALMET.

Upper Air Data Stations and Processing

Upper air data was processed from three weather stations including West Palm Beach, Key West and Tampa, in Florida. The upper air data were extracted from the NCDC Radiosonde Data CD and processed into the NCDC Tape Deck (TD) 6201 format by the CALMET preprocessor utility program, READ62, to create an upper air file for each station. A summary of the surface, over-water, and upper air stations used in the air modeling analysis is presented in Table 5-4.

Precipitation Data Stations and Processing

Hourly precipitation data were developed for 23 primary and secondary NWS precipitation stations located in southern Florida. The stations were selected so as to provide detailed coverage in all areas within and around the CALMET modeling domain. The hourly precipitation data were extracted from data obtained by the NCDC and organized by EarthInfo on CD. These CD data were extracted into Tape Deck (TD) 3240 format. Once in TD3240 format, the hourly precipitation data for each of the 23 stations were extracted and then re-merged into CALMET input format (PRECIP.DAT) using the utility programs PXTRACT and PMERGE, respectively. A listing of the precipitation stations used for air modeling analysis is presented in Table 5-5.

Geophysical Data Processing

Terrain elevations for each grid cell of the modeling domain were obtained from 1-degree Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS) internet website. The DEM data for the modeling domain grid was processed using the utility program TERREL. One-degree land-use data was also obtained from the USGS website. The land-use parameters for the air modeling domain were developed using the CALMET preprocessor utility programs CTGCOMP and GTGPROC. Other processed parameters extracted with the land use data are surface roughness, surface albedo, Bowen ratio, soil heat flux, and leaf index field. The processed land-use parameters were combined with the processed terrain elevation data to create the GEO.DAT file that was input to CALMET.

5.1.5 EMISSION INVENTORY

Proposed Project

The proposed project will result in a net increase for PM_{10} and NO_x that exceed PSD significant emission rates. A summary of future emissions and operating data for Boiler No. 16 is presented in Table 5-6. The proposed emissions and stack parameters for Boiler No. 16 for the future operating condition were obtained from Tables 2-1 and 2-2.

While the future Boiler No. 16 can operate year-round, currently Boiler No. 16 is restricted to 175 days during off-season months of March through October (4,200 hours) and during the crop season, it is only permitted to operate if one or more of the cogeneration boilers is down. The current operation of Boiler No. 16 was not modeled since the current emissions are assumed to be zero. For the future operation of Boiler No. 16, the boiler was modeled for 8,760 hr/yr since the future operating hours will not be restricted.

5.1.6 BUILDING DOWNWASH EFFECTS FOR OKEELANTA SUGAR MILL

Based on the building dimensions associated with buildings and structures at the Okeelanta Sugar Mill, Boiler No. 16 will comply with the good engineering practice (GEP) stack height regulations. However, the stack is less than GEP height. Therefore, the potential for building downwash to occur was considered in the air modeling analysis for Boiler No. 16.

Generally, a stack is considered to be within the influence of a building if it is within the lesser of 5 times L, where L is the lesser dimension of the building height or projected width. The ISCST3 model uses two procedures to address the effects of building downwash. For both methods, the direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector. The H_b is the building height and L_b is the lesser of the building height or projected width. For short stacks (i.e., physical stack height is less than $H_b + 0.5\,L_b$), the Schulman and Scire (1980) method is used. The features of the Schulman and Scire method are as follows:

1. Reduced plume rise as a result of initial plume dilution,
2. Enhanced plume spread as a linear function of the effective plume height, and
3. Specification of building dimensions as a function of wind direction.

For cases where the physical stack height is greater than $H_b + 0.5\,L_b$, but less than GEP, the Huber-Snyder (1976) method is used. Both downwash algorithms affect stacks that are within the influence of a building, without regard for the actual distance the stack or stack's plume from the building.

The building dimensions considered in the air modeling analysis for the Okeelanta Sugar Mill are presented in Table 5-7. The location of the mill's buildings and stacks can be found on the site plot plans included with the PSD permit application and shown in Attachment OC-FI-C2.

5.1.7 RECEPTOR LOCATIONS

The maximum concentrations in the vicinity of the facility and the distances of the project's significant impacts were predicted in a receptor grid that contained 507 receptors. This grid had both discrete and gridded polar receptors. The number of discrete receptors was 393. These receptors were spaced at 100-meter intervals along the property boundary. The other 114 receptors were included in a polar grid, with 36 radials extending out from the origin. Along each radial, receptors were located at distances of 4.0, 5.0, 7.0, and 10.0 km from the origin. A figure depicting the receptors and property boundaries used in the modeling analysis is presented in Figure 5-1. To the east, U.S. 27 is the nearest public access. This road is bounded by canals that prevent access into the cane fields surrounding the Okeelanta Sugar Mill. To the north, the entire property is bounded by the Bolles canal. To the west, the property is bounded by the Miami Canal. To the south, the property is bounded by a public road that runs west off of U.S. 27. No trespassing signs or gated roads restrict public access onto the property from any access roads. An expanded view of the buildings and structures is presented in Figure 5-2.

Pollutant concentrations for PM_{10}, NO_x, and CO were also predicted at 126 receptors located along the northern and eastern boundaries of the Everglades National Park ENP PSD Class I area. A listing of the 126 ENP receptors is presented in Table 5-8.

5.2 AIR MODELING RESULTS

5.2.1 SIGNIFICANT ANALYSIS

Site Vicinity

The predicted maximum PM_{10}, NO_x, and CO concentrations due to the proposed project are presented in Table 5-9. Based upon the screening analyses, the proposed project was determined to not have a significant impact for the annual and 24-hour average PM_{10} concentrations, the annual NO_x concentration and the 8- and 1-hour average CO concentrations. Therefore, no additional detailed modeling analyses are required for these pollutants.

PSD Class I

A summary of the maximum impacts of PM_{10}, NO_x, and CO for the significant impact analysis at the ENP Class I area is presented in Table 5-10. The predicted impacts for PM_{10} and NO_x are well below the significant impact levels proposed by the EPA. The maximum impacts are below the criteria; therefore, Boiler No. 16 is not expected to adversely impact the ENP.

Table 5-1. Major Features of the ISCST3 Model, Version 10100

Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations
• Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975; Bowers, et al., 1979).
• Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulman and Scire (1980) for evaluating building wake effects
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
• Separation of multiple emission sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, area, and open pit sources
• Capability to calculate dry and wet deposition, including both gaseous and particulate precipitation scavenging for wet deposition
• Variation of wind speed with height (wind speed-profile exponent law)
• Concentration estimates for 1-hour to annual average times
• Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm for ISCST3; a built-in algorithm for predicting concentrations in complex terrain
• Consideration of time-dependent exponential decay of pollutants
• The method of Pasquill (1976) to account for buoyancy-induced dispersion
• A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
• Procedure for calm-wind processing including setting wind speeds less than 1 m/s to 1 m/s.

Note: ISCST = Industrial Source Complex Short-Term Model.
Source: EPA, 2000.

Table 5-2. CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, and NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG /MP coefficients, rural mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration file including output species for SO_4, NO_3 and PM_{10}
Model Processing	Highest predicted 24-hour SO_4, NO_3 and PM10 concentrations for year
Background Values	Ozone: 80 ppb; Ammonia: 10 ppb

Table 5-3. CALMET Settings

Parameter	Setting
Horizontal Grid Dimensions	450 by 470 km, 5 km grid resolution
Vertical Grid	9 layers
Weather Station Data Inputs	8 surface, 3 upper air, 23 precipitation stations, 3 overwater
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	MM4 data, 80 km resolution, 8 x 8 grid, used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input

Table 5-4. Surface, Overwater, and Upper Air Stations Used in the PSD Class I CALPUFF Modeling Analysis

Station Name	Station Symbol	WBAN Number	UTM Coordinate Easting (km)	UTM Coordinate Northing (km)	UTM Coordinate Zone	Anemometer Height (m)	Time Zone[a]
Surface Stations							
Orlando, Florida	ORL	12815	468.96	3146.88	17	10.1	5
Fort Myers, Florida	FMY	12835	413.65	2940.38	17	6.1	5
Vero Beach, Florida	VER	12843	557.52	3058.36	17	6.7	5
Daytona Beach, Florida	DAB	12834	495.14	3228.05	17	9.1	5
Key West, Florida	EYW	12836	424.03	2715.14	17	18.3	5
Miami, Florida	MIA	12839	566.82	2857.20	17	7	5
Tampa, Florida	TPA	12842	349.20	3094.21	17	6.7	5
West Palm Beach, Florida	PBI	12844	587.87	2951.43	17	10.1	5
Overwater Stations							
Sombrero Key, Florida	SMKF1		488.87	2723.79	17	10	5
Lake Worth, Florida	LKWF1		596.58	2943.40	17	13.4	5
Venice, Florida	VENF		356.20	2994.80	17	7.3	5
Upper Air Stations							
Tampa, Florida	TPA	12842	349.20	3094.28	17	NA	5
West Palm Beach, Florida	WPB	12844	587.87	2951.42	17	NA	5
Key West, Florida	EYW	12836	424.03	2715.14	17	NA	5

[a] Eastern Time Zone= 5

Table 5-5. Hourly Precipitation Stations Used in the PSD Class I Analysis

Station Name	Station Number	UTM Coordinate Easting (km)	Northing (km)	Zone
Belle Glade HRCN GT 4	080616	528.190	2953.034	17
Boca Raton	080845	588.748	2916.516	17
Canal Point Gate 5	081271	536.428	2971.514	17
Clewiston US Engineers	081654	546.189	2912.725	17
Fort Myers FAA/AP	083186	413.992	2940.710	17
Homestead Exp Stn	084091	550.257	2820.210	17
Key West Intl. Airport	084570	423.669	2715.509	17
Miami WSCMO Airport	085663	570.198	2856.167	17
Moore Haven Lock 1	085895	491.608	2967.803	17
North New River Canal	086323	546.578	2912.480	17
Ortona Lock 2	086657	470.174	2962.267	17
Parrish	086880	366.986	3054.394	17
Pennsuco 5 WNW	086988	554.695	2867.814	17
Port Mayaca S L Canal	087293	538.044	2984.440	17
St Lucie New Lock 1	087859	571.042	2999.353	17
St Petersburg	087886	339.608	3071.991	17
Tamiami Trail 40 mi Bend	088780	517.635	2849.040	17
Tampa WSCMO Airport	088788	348.478	3093.670	17
Trail Glade Ranges	089010	551.565	2849.990	17
Venice	089176	357.593	2998.178	17
Venus	089184	467.266	3001.224	17
Vero Beach 4 W	089219	554.268	3056.498	17
West Palm Beach Intl Airport	089525	589.611	2951.627	17

Table 5-6. Future Operating Parameters for Boiler No. 16, Okeelanta Corporation

Parameter	Value	
Stack Height	75 ft	
Stack Diameter	5 ft	
Gas Flow Rate	88,200 acfm	
Velocity	75 ft/s	
Temperature	410 deg. F	
Regulated Pollutant	Hourly Emissions	
	(lb/hr)	(g/s)
Particulate Matter (PM)	6.46	0.81
Particulate Matter (PM_{10})	6.46	0.81
Sulfur dioxide (SO_2)	11.66	1.47
Nitrogen oxides (NO_x)	30.30	3.82
Carbon monoxide (CO)	32.32	4.07
VOC	6.33	0.80
Sulfuric acid mist (SAM)	0.52	0.07
Lead (Pb)	1.82E-03	2.29E-04
Mercury (Hg)	6.06E-04	7.64E-05
Beryllium (Be)	6.06E-04	7.64E-05
Fluorides (Fl)	--	--

Table 5-7. Summary of Building Structures Used in the Air Modeling Analysis for Okeelanta Boiler No. 16

Structure	Height (ft)	Height (m)	Length (ft)	Length (m)	Width (ft)	Width (m)
Mill Tandems A & B	55	16.8	605.2	184.5	144.9	44.2
North and South Evaporators Buildin	75	22.9	157.8	48.1	118.9	36.2
Power Plant Building	46	14.0	50.0	15.2	67.3	20.5
Silo Tank[a]	80	24.4	135.5	41.3	135.5	41.3
Refinery Building	90	27.4	287.0	87.5	72.4	22.1

Footnotes:

[a] For modeling purposes, the tank was assumed to be square shaped.

Table 5-8. Summary of Receptors Used for the PSD Class I CALPUFF Modeling Analysis, Everglades National Park

Receptor Number	UTM Coordinate (m) Easting	Northing	Receptor Number	UTM Coordinate (m) Easting	Northing	Receptor Number	UTM Coordinate (m) Easting	Northing
1	557000	2789000	43	532000	2848600	85	504000	2832500
2	556600	2792000	44	531000	2848600	86	503000	2832500
3	556000	2796000	45	530000	2848600	87	502000	2832500
4	553000	2796500	46	529000	2848600	88	501000	2832500
5	548000	2796500	47	528000	2848600	89	500000	2832500
6	542700	2796500	48	527000	2848600	90	499000	2832500
7	542700	2800000	49	526000	2848600	91	498000	2832500
8	542700	2805000	50	525000	2848600	92	497000	2832500
9	542700	2810000	51	524000	2848600	93	496000	2832500
10	542000	2811000	52	523000	2848600	94	495000	2832500
11	541300	2814000	53	522000	2848600	95	495000	2833000
12	542700	2816000	54	521000	2848600	96	495000	2834000
13	544100	2820000	55	520000	2848600	97	495000	2835000
14	543500	2824600	56	519000	2848600	98	495000	2836000
15	545000	2829000	57	518000	2848600	99	494500	2837000
16	545700	2832200	58	517000	2848600	100	491500	2841000
17	546200	2835700	59	516000	2848600	101	488500	2845500
18	548600	2837500	60	515000	2848600	102	483000	2848500
19	550300	2839000	61	514500	2848600	103	480000	2852500
20	545000	2839000	62	514500	2848000	104	475000	2854000
21	540000	2839000	63	514500	2847600	105	473500	2857000
22	550500	2844000	64	514500	2846600	106	473000	2860000
23	545000	2844000	65	514500	2845000	107	472000	2860000
24	540000	2844000	66	514500	2844000	108	471000	2860000
25	550300	2848600	67	514500	2843000	109	470000	2860000
26	549000	2848600	68	514500	2842000	110	469000	2860000
27	548000	2848600	69	514500	2841000	111	468000	2860000
28	547000	2848600	70	514500	2840000	112	467000	2860000
29	546000	2848600	71	514500	2839000	113	466000	2860000
30	545000	2848600	72	514500	2838000	114	465000	2860000
31	544000	2848600	73	514500	2837000	115	464000	2860000
32	543000	2848600	74	514500	2836000	116	463000	2860000
33	542000	2848600	75	514500	2835000	117	462000	2860000
34	541000	2848600	76	514500	2834000	118	461000	2860000
35	540000	2848600	77	514500	2833000	119	460000	2860000
36	539000	2848600	78	514500	2832500	120	459500	2863200
37	538000	2848600	79	510000	2832500	121	459000	2863200
38	537000	2848600	80	509000	2832500	122	458000	2863200
39	536000	2848600	81	508000	2832500	123	457000	2863200
40	535000	2848600	82	507000	2832500	124	456000	2863200
41	534000	2848600	83	506000	2832500	125	455000	2863200
42	533000	2848600	84	505000	2832500	126	454000	2863200

All receptors are in UTM zone 17

Table 5-9. Maximum Predicted Pollutant Impacts From Boiler No. 16 Compared to EPA Significant Impact Levels

Averaging Time	Concentration[a] (μg/m³)	Receptor Location[b] Direction (degree)	Distance (m)	Time Period (YYMMDDHH)	EPA Class II Significant Impact Levels (μg/m³)
PM_{10}					
Annual	0.08	136.7	3920.2	87123124	1
	0.10	155.7	3130.8	88123124	
	0.09	141.3	3657.5	89123124	
	0.06	147.9	3367.4	90123124	
	0.08	159.1	3053.9	91123124	
High 24-Hour	1.01	143.8	3535.9	87112824	5
	0.96	164.6	2960.4	88120424	
	1.11	141.3	3657.5	89020824	
	1.13	149.4	3315.4	90030624	
	1.07	159.1	3053.9	91012324	
NO_x					
Annual	0.37	136.7	3920.2	87123124	1
	0.45	155.7	3130.8	88123124	
	0.40	141.3	3657.5	89123124	
	0.29	147.9	3367.4	90123124	
	0.36	159.1	3053.9	91123124	
CO					
High 8-Hour	12.29	143.8	3535.9	87112808	500
	12.59	160.9	3019.8	88123108	
	15.07	141.3	3657.5	89020808	
	12.81	149.4	3315.4	90030608	
	15.97	159.1	3053.9	91012308	
High 1-Hour	37.50	174.2	2868.1	87041105	2,000
	37.22	170.3	2895.0	88052701	
	37.54	174.2	2868.1	89122819	
	36.99	172.3	2879.8	90092505	
	37.68	174.2	2868.1	91101905	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler No. 16 Stack Location

Legend:
YYMMDDHH = Year, Month, Day, Hour Ending
EPA = Environmental Protection Agency

Table 5-10. Maximum Predicted Pollutant Impacts From Boiler No. 16 at the ENP PSD Class I Area

Averaging Time	Concentration[a] ($\mu g/m^3$)	EPA Proposed Class I Significant Impact Levels ($\mu g/m^3$)
PM_{10}		
Annual	0.0005	0.2
High 24-Hour	0.0226	0.3
NO_x		
Annual	0.001	0.1
CO		
High 8-Hour	0.219	NA
High 1-Hour	0.316	NA

Note:

[a] Based on modeling results from using the south Florida windfield in the CALPUFF model.

[b] Universal Mercator Transverse coordinate system.

Legend:

YYMMDDHH = Year, Month, Day, Hour Ending
PSD = Prevention of Significant Deterioration
NPS = National Park Service
EPA = Environmental Protection Agency
NA = Not Applicable

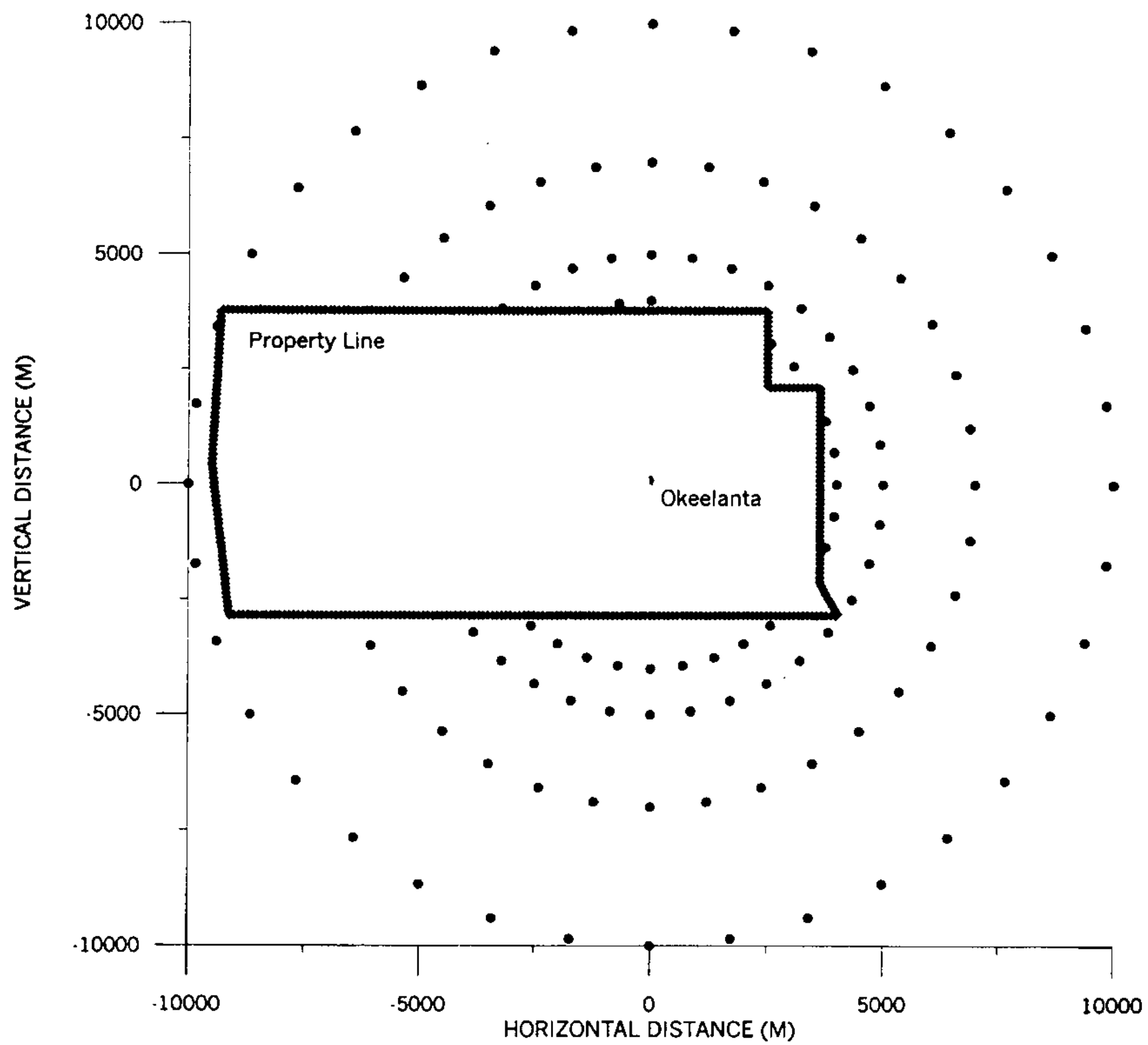

Figure 5-1
Property Line and Discrete Receptors Used in Modeling Analysis, Okeelanta Corporation

Golder Associates

Source: Golder, 2001.

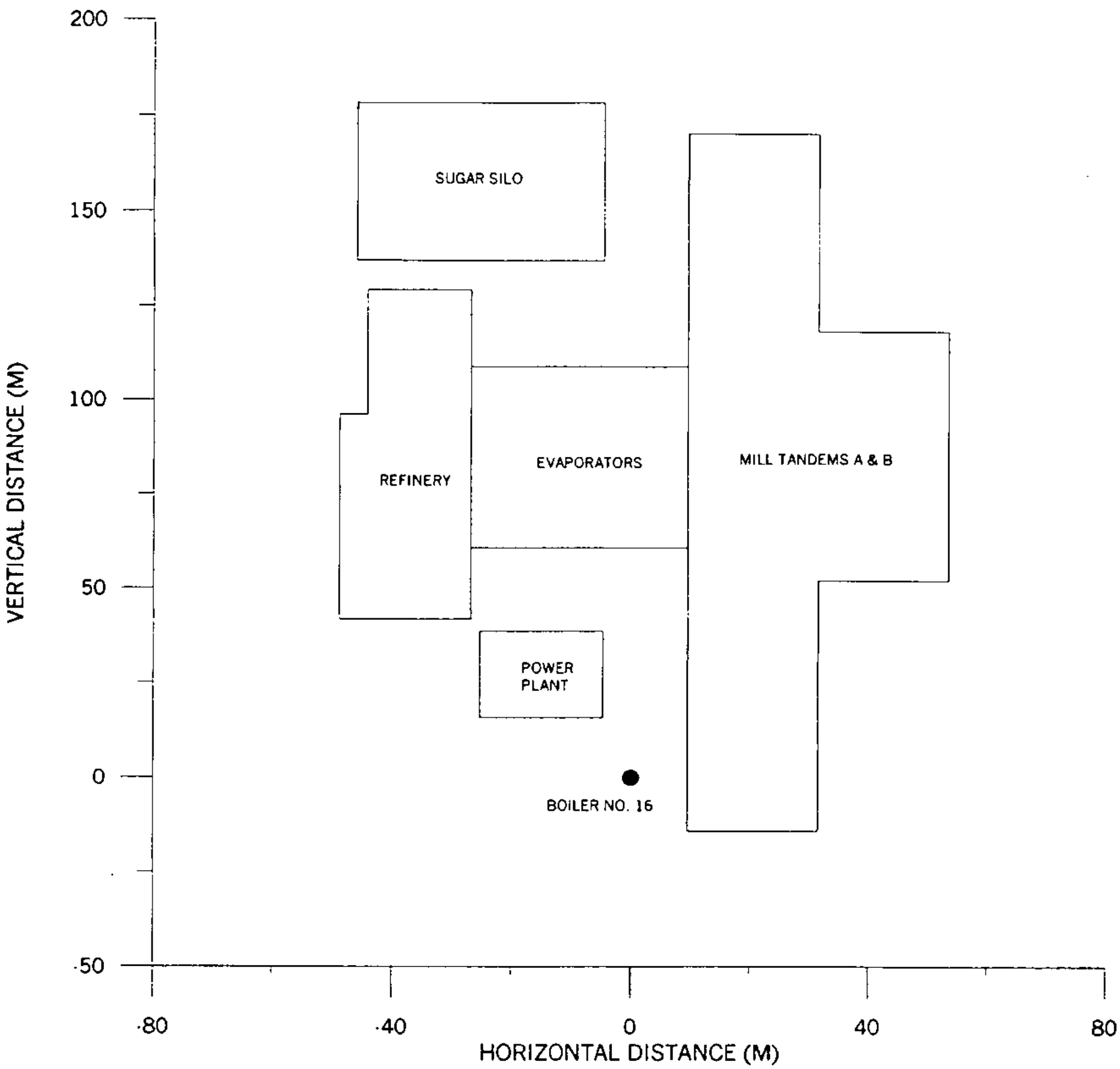

Figure 5-2
Expanded View of Building and Structures Used in Modeling Analysis
Okeelanta Corporation

Source: Golder, 2001.

Golder Associates

6.0 ADDITIONAL IMPACT ANALYSES

6.1 INTRODUCTION

Okeelanta is proposing to modify Boiler No. 16 at its existing facility in South Bay, Florida. The facility is subject to the PSD review requirements for PM_{10}, NO_x, CO and Be. The additional impact anaysis and the Class I area analysis addresses these pollutants.

The analysis addresses the potential impacts on vegetation, soils and wildlife of the surrounding area and the nearest Class I area due to Okeelanta's proposed modification. The nearest Class I area is the Everglades National Park (ENP), located approximately 92 km south of the facility. In addition, potential impacts upon visibility resulting from the proposed modification are assessed.

The analysis will demonstrate that the increase in impacts due to the proposed increase in emissions is extremely low. Regardless of the existing conditions in the vicinity of the site or in the Class I areas, the proposed project will not cause any significant adverse affects due to the predicted low impacts upon these areas.

6.2 VICINITY OF SOUTH BAY

The primary vegetation in the vicinity of the Okeelanta facility is sugar cane. Some vegetable farming, nurseries, and sod farms are also located in the general area. Soils in the area are primarily peat-type soils.

As described in the air quality impact analysis (Section 5.0), the maximum predicted CO, NO_2, and PM_{10} concentrations in the vicinity of the site as a result of Boiler No. 16 are predicted to be below SIL. No detrimental effects on soils or vegetation should occur in this area due to the project. The potential impacts of NO_2, PM_{10}, and CO upon soils, vegetation, and visibility in the Everglades National Park are addressed in the following sections.

6.3 PSD CLASS I AREA

This section focuses on the ecological effects of the proposed facility modification on Air Quality Related Values (AQRV), as defined under PSD regulations, in the ENP. The AQRVs are defined as being:

> "All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way on the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality. Important attributes of an area are those values or assets that make an area significant as a monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside" (Federal Register, 1978).

The AQRVs include freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) are also evaluated.

A screening approach was used that compared the maximum predicted ambient concentration of air pollutants of concern in the Everglades NP (Table 6-1) with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted that specifically addressed the effects of air contaminants on plant species reported to occur in the park. While the literature search focused on such species as cabbage palm, Eastern red cedar, lichens, and species of the hardwood swamplands and mangrove forest, few specific citations that addressed these species were found. It is recognized that effect threshold information is not available for all species found in the Everglades National Park, although studies have been performed on a few of the common species and on other similar species that can be used as indicators of effects.

6.3.1 IMPACTS TO SOILS

For soils, the potential and hypothesized effects of atmospheric deposition include:

- Increased soil acidification,
- Alteration in cation exchange,
- Loss of base cations, and
- Mobilization of trace metals.

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

The soils of the Everglades National Park are generally classified as histosols or entisols. Histosols (peat soils) are organic and have extremely high buffering capacities based on their CEC, base saturation, and bulk density. Therefore, they would be relatively insensitive to atmospheric inputs. The entisols are shallow sandy soils overlying limestone, such as the soils found in the pinelands. The direct connection of these soils with subsurface limestone tends to neutralize any acidic inputs. Moreover, the groundwater table is highly buffered due to the interaction with subsurface limestone formations, which results in high alkalinity (as $CaCO_3$).

The relatively low sensitivity of the soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants projected for the Everglades National Park from Boiler No. 16 emissions precludes any significant impact on soils.

6.3.2 IMPACTS TO VEGETATION

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

Injury to vegetation from exposure to various levels or air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation. This is a conservative approach.

The concentration of the pollutant, duration of exposure, and frequency of exposures influence the response of vegetation and wildlife to atmospheric pollutants. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration which occur during certain meteorological conditions interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants and animals they will be from the short-term, higher doses. A dose is the product of the concentration of the pollutant and duration of the exposure.

Nitrogen Dioxide

Atmospheric nitrogen dioxide (NO_2) injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of NO_2 can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru et al., 1979).

Plant damage can occur through either acute (short-term, high concentration) or chronic (long-term, relatively low concentration) exposure. For plants that have been determined to be more sensitive to NO_2 exposure than others, acute (1, 4, and 8 hours) exposure caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 $\mu g/m^3$ (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered NO_2-sensitive) to NO_2 concentrations of 2,000 to 4,000 $\mu g/m^3$ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975).

By comparison of published toxicity values for NO_2 exposure to short-term (i.e., 1-, 3-, and 8-hour averaging times) and long-term (annual averaging time) modeled concentrations, the possibility of plant damage in the park can be examined for both acute and chronic exposure situations, respectively. The 1-, 3-, and 8-hour estimated NO_2 concentrations due to Boiler No. 16 at the point of maximum impact in the park area are 0.188, 0.149, and 0.137 $\mu g/m^3$, respectively. These concentrations are less than 0.01 percent of the levels that cause foliar injury to sensitive plant species. For a chronic exposure, the annual estimated NO_2 concentration due to Boiler No. 16 at the point of maximum impact in the ENP (0.001 $\mu g/m^3$) is less than 0.001 percent of the levels that caused minimal yield loss and chlorosis in plant tissue.

Particulate Matter

Although information pertaining to the effects of PM on plants is scarce, baseline concentrations are available (Mandoli and Dubey, 1988). Ten species of native Indian plants were exposed to levels of PM that ranged from 210 to 366 $\mu g/m^3$ for an 8-hour averaging period. Damage in the form of a higher leaf area/dry weight ratio was observed at varying degrees for most plants tested. Concentrations of PM lower than 163 $\mu g/m^3$ did not appear to be injurious to the tested plants.

By comparison of published toxicity values for PM exposure (i.e., 8-hour averaging time) concentrations, the possibility of plant damage in the park due to Boiler No. 16 can be determined. The 8-hour estimated PM_{10} concentration due to the project only at the point of maximum impact in the park area is 0.042 $\mu g/m^3$. This concentration is approximately 0.02 percent of the lower value that affected plant foliage. The extremely small additional impact the facility is predicted to have on the ENP will not cause any adverse affects to vegetation.

Carbon Monoxide

As with PM, information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome *c* oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome *c* oxidase depletes the supply of ATP, the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok et al. (1989) reported that exposure to $CO:O_2$ ratio of 25 (equivalent to an ambient CO concentration of 6.85×10^6 $\mu g/m^3$) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik et al. (1992) reported cytochrome *c* oxidase inhibition in corn, sorghum, millet, and Guinea grass at $CO:O_2$ ratios of 2.5 (equivalent to an ambient CO concentration of 6.85×10^5 $\mu g/m^3$). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase. The predicted annual average CO impact due to Boiler No. 16 at the ENP (0.003 $\mu g/m^3$) is well below these published effects levels.

Summary

In summary, the phytotoxic effects on the ENP from Boiler No. 16 emissions are expected to be minimal. It is important to note that the substances were evaluated with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

6.3.3 IMPACTS TO WILDLIFE

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary ambient air quality standards. Physiological and behavioral effects have been observed in experimental animals at or below these standards. No observable effects to fauna are expected at concentrations below the values reported in Table 6-2.

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the National Ambient Air Quality Standards. This occurs in non-attainment areas, e.g., Los Angeles Basin. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1981).

For impacts on wildlife, the lowest threshold values of SO_2, NO_x, and particulates which are reported to cause physiological changes are shown in Table 6-2. These values are up to several orders of magnitude larger than maximum predicted concentrations for the Class I area. No effects on wildlife AQRVs from NO_x and particulate matter are expected. These results are considered indications of the risk of other air pollutant emissions predicted from the facility.

6.4 IMPACTS ON VISIBILITY

6.4.1 REGIONAL HAZE

Introduction

A change in visibility is characterized by either a change in the visual range, defined as the greatest distance that a large dark object can be seen, or by a change in the light-extinction coefficient (b_{ext}). The b_{ext} is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where b_{exts} is the extinction coefficient calculated for the source, and
b_{extb} is the background extinction coefficient.

The source extinction coefficient is determined from NO_x, SO_2, and PM_{10} emission increases from the facility. The background extinction coefficients for each area evaluated are based on existing ambient monitoring data. Based on predicted SO_4, NO_3, and PM_{10} concentrations, the facility's emissions were compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5.

The modeling analysis determined the deciview change at the Everglades National Park, a PSD Class I area located 92 km from the Okeelanta facility.

6.4.2 ANALYSIS METHODOLOGY

Following the recommendations of the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II report, a level II screening analysis was performed using the California Puff (CALPUFF) long-range transport model, along with an enhanced ISC meteorological data record from Palm Beach. The CALPUFF postprocessor model CALPOST was used to summarize the daily deciview values predicted with the CALPUFF model, and hourly relative humidity data from West Palm Beach.

CALPUFF was used in a manner recommended by the IWAQM Phase 2 Summary Report (EPA, 12/98). A summary of the recommended parameter settings used with CALPUFF are presented in Appendix B with the recommended parameter settings presented in Appendix B of the IWAQM Phase II Summary Report. The CALPUFF model was used in an ISC screening mode with an "enhanced" ISCST3 meteorological data set.

The following CALPUFF settings/values were implemented in the Level II screening analysis:

- Use of seven pollutant species of SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10}, and CO.
- Use of MESOPUFF II scheme for chemical transformation with CALPUFF default background concentrations
- Include both dry and wet deposition and plume depletion
- Use Agricultural, unirrigated land use; minimum mixing height of 50 m
- Use transitional plume rise, stack-tip downwash, and partial plume penetration
- Use puff plume element dispersion, PG/MP coefficients, rural mode, and ISC building downwash scheme
- Use partial plume path adjustment terrain effects
- Generate an hourly RH file for each year processed

6.4.3 EMISSION INVENTORY

Based on recommendations of the Federal Land Manager's Air Quality Related Values Workgroup (FLAG) Phase I Summary Report (12/00), the regional haze analysis considered only the maximum 24-hour increase in emissions due to the proposed Boiler No. 16 modification. The emission rates used in the analysis for Boiler No. 16 are 1.47 g/s for SO_2, 3.82 g/s for NO_x, 4.07 g/s for CO, and 0.81 g/s for PM_{10}.

6.4.4 BUILDING WAKE EFFECTS

The CALPUFF analysis included the direction-specific building heights and projected widths to account for the effects of building-induced downwash on Boiler No. 16. The building dimensions used in the CALPUFF model are identical to those processed for the Industrial Source Complex Short-Term (ISCST) model using the Building Profile Input Program (BPIP), Version 95086. The building data from the ISCST model were converted to CALPUFF model input format using the utility program ISC2PUF.

6.4.5 RECEPTOR LOCATIONS

The CALPUFF analysis used an array of receptors of sufficient density and extent to adequately predict the pattern of pollutant impacts at the ENP. Specifically, the array consisted of 126 receptors located along the boundary and within the ENP. Receptors were generally located within the area with a spacing of 1 km. Table 5-8 includes the receptors used for the analysis. Because the ENP is flat and at sea level, all receptors were assigned an elevation of zero.

6.4.6 BACKGROUND VISUAL RANGE AND RELATIVE HUMIDITY FACTORS

The regional haze analysis was performed using the latest regulatory guidance as provided in the Federal Land Manager's Air Quality Related Values Workgroup (FLAG) Phase I report. Using the hourly meteorological and relative humidity data used with the CALPUFF model, the daily change is background extinction is computed. The hygroscopic and dry non-hygroscopic components used for calculating the daily background extinction coefficients for the ENP were obtained from the FLAG report. For this analysis, the hygroscopic and dry non-hygroscopic values were 0.9 and 8.5 inverse millimeters (mm^{-1}), respectively.

6.4.7 METEOROLOGICAL DATA

The California Puff meteorological and geophysical data preprocessor (CALMET, Version 5.4) was used to develop the gridded parameter fields required for the PSD Class I significant impact modeling analysis. Please refer to Section 5.1.4 for the discussion of the specific data used and processed in the CALMET model.

6.4.8 CHEMICAL TRANSFORMATION

The air modeling analysis included all chemical transformation processes that occur for the emitted species.

6.4.9 RESULTS

The maximum predicted 24-hour change in background extinction coefficient is 0.91 percent or 0.091 deciview. As this percentage is below the criteria value of 5 percent, it is concluded that the proposed project will not adversely impact the background visibility levels at the ENP Class I area.

Table 6-1. Maximum Predicted Pollutant Impacts Due to Boiler No. 16 at ENP

Pollutant	Concentration for Averaging Times ($\mu g/m^3$)				
	Annual	24-Hour	8-Hour	3-Hour	1-Hour
Nitrogen Dioxide (NO_2)	0.001	0.051	0.137	0.149	0.188
Particulate Matter (PM_{10})	0.0005	0.0226	0.042	0.051	0.061
Carbon Monoxide (CO)	0.003	0.116	0.219	0.263	0.316

Source: Golder Associates, 2000

Table 6-2. Examples of Reported Effects of Air Pollutants on Animals at Concentrations Below National Secondary Ambient Air Quality Standards

Pollutant	Reported Effect	Concentration ($\mu g/m^3$)	Exposure
Nitrogen Dioxide[1,2]	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates[3]	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	continually for 2 months
	Decreased respiratory disease defenses in rats, same with hamsters	100 $NiCl_2$	2 hours

Source:
[1] Gardner and Graham, 1976.
[2] Trzeciak et al., 1977.
[3] Newman and Schreiber, 1988.

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APPENDIX A
EQUATIONS AND FACTORS USED IN SCR COST EFFECTIVENESS CALCULATIONS

PB98-147218

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-453/R-95-012
June 1997

Air

New Source Performance Standards, Subpart Db - Technical Support for Proposed Revisions to NOx Standard

NSPS

CF = Capacity factor (decimal fraction)
0.5 = Mole urea/mole NH_2
60 = Molecular weight of urea
46 = Molecular weight of NO_x
2000 = lb/ton
8760 = hr/yr
2 = lb urea mixture/lb pure urea

Based upon the case studies, the other variable O&M costs were estimated to be 11 percent of the annual urea cost. Therefore the total VO&M costs for SNCR were calculated from:

$$VO\&M\ (\$/yr) = 1.11 * \text{Urea Cost} \tag{B.18}$$

B.4 Selective Catalytic Reduction

The SCR cost algorithms developed for utility boilers were used to estimate costs for industrial boilers. The algorithms are based on hot-side SCR technology (i.e., the catalyst is located between the boiler economizer and air preheater). Catalyst life was assumed to be three years for coal-fired boilers and six years for natural gas-and oil-fired boilers. A normalized stoichiometric ratio of 0.82 and a NO_x reduction of 80 percent was assumed for all cases. At this NO_x reduction, catalyst space velocities were assumed to be 3,200/hr for coal-fired boilers, 5,000/hr for oil-fired boilers, and 14,000/hr for natural gas-fired boilers. The cost of catalyst was assumed to be $350/ft^3.

B.4.1 Direct Cost

Direct cost for SCR includes both process capital and the initial catalyst charge:

$$DC\ [\$/(MMBtu/hr)] = \text{process capital} + \text{initial catalyst charge} \tag{B.19}$$

Process capital is calculated by an equation of the form:

$$\text{Process capital } [\$/(\text{MMBtu/hr})] = a * (\text{size})^{b} \qquad (B.20)$$

Process capital includes ammonia handling, storage, and injection; catalyst reactor housing; flue gas handling, air preheater modifications; and process control. Cost equations derived for wall, coal-fired boilers were used to cost all coal-fired industrial boilers. A similar approach was used for oil- and gas-fired boilers. The equations are listed below.

For coal-fired boilers:

$$\text{Process Capital } [\$/(\text{MMBtu/hr})] = 34{,}718*(\text{size})^{-0.3} \qquad (B.21)$$

For residual oil-, distillate oil-, and gas-fired boilers:

$$\text{Process capital } [\$/(\text{MMBtu/hr})] = 35{,}276*(\text{size})^{-0.33} \qquad (B.22)$$

The equation for estimating the cost of the initial catalyst charge is calculated from:

$$\text{Catalyst cost } [\$/(\text{MMBtu/hr})] = \text{Flow} * \text{Cat\$} / \{SV_f * [\ln(0.20) / \ln(1 - NO_x\text{Red})]\} * 100 \qquad (B.23)$$

where:

Flow = Fuel-specific flue gas flow rate in normal cubic feet per kilowatt-hour (Nft^3/kWh); (126 Nft^3/kWh for coal, 100 Nft^3/kWh for natural gas and oil)

Cat\$ = Catalyst cost (\$/ft^3) (assumed to be \$400/ft^3 for all fuel types)

SV_f = Fuel-specific space velocity (hr^{-1}) (3,200/hr for coal, 5,000/hr for oil, and

14,000/hr for distillate oil/natural gas)

NO_xRed = Target NO_x reduction efficiency (decimal fraction)

100 = Conversion factor (assumed 100 kW/MMBtu per hr)

B.4.2 Indirect Cost

Separate indirect cost factors were used for the process capital and the catalyst cost. Indirect costs for the process capital were estimated at 45 percent (ICF = 1.45). Indirect cost factors for the catalyst were estimated at 1.25 for coal-fired boilers, 1.20 for oil-fired boilers, and 1.15 for gas-fired boilers.

Total capital cost is calculated by multiplying the process capital by the process capital indirect cost factor, multiplying the initial catalyst charge by the catalyst indirect cost factor, and adding these two products together.

B.4.3 Fixed O&M Costs

Fixed O&M costs for SCR include operating, supervisory, and maintenance labor; and maintenance materials. Fixed O&M cost equations used here are the same as those derived for the subpart Da model boilers. The equations derived for wall, coal-fired boilers and wall, oil-and gas-fired boilers are shown below.

For coal-fired boilers, the FO&M costs estimated from:

$$\text{FO\&M (\$/yr)} = 284{,}600 + 514 * (\text{size}) \tag{B.24}$$

where:

284,600 and 514 = Regression coefficients

size = Boiler capacity, MMBtu/hr

and for oil- and gas-fired boilers the FO&M costs were estimated from:

$$\text{FO\&M (\$/yr)} = 264{,}800 + 326 * (\text{size}) \tag{B.25}$$

where:

264,800 and 326 = Regression coefficients

size = Boiler capacity, MMBtu/hr

B.4.4 Variable O&M Costs

Variable O&M costs for SCR include catalyst replacement and disposal, ammonia, electricity, and steam. Cost for these elements are the same as those derived for utility boilers.

Catalyst replacement and disposal cost ($/yr) =

$$\text{Flow}*(\text{Cat\$} + 160) \; / \; \{SV_f*[\ln(0.20) \; / \; \ln(1-NO_xRed)]\} \; / \; CL * (\text{size}) * 100 \qquad (B.26)$$

where:

Cat $ = Catalyst cost ($/ft^3) (assumed to be $350/ft^3)

160 = Cost to cover installation and disposal of replacement catalyst ($/ft^3)

SV_f = Fuel-specific space velocity (hr^{-1}) (3,200/hr for coal, 5,000/hr for oil, and 14,000/hr for distillate oil/natural gas)

NO_xRed = Target NO_x reduction efficiency (decimal fraction)

CL = Catalyst life (years)

Size = Boiler capacity, MMBtu/hr

100 = conversion factor

The equation for estimating costs for the other variable O&M components is:

$$\text{Other VO\&M Cost (\$/yr)} = [1.88 + (4.3 * UncNO_x * NO_xRed)] * CF * (\text{size}) * 100 \qquad (B.27)$$

where:

1.88 and 4.3 = Regression coefficients

$UncNO_x$ = NO_x emission rate at inlet to SCR system (lb/MMBtu)

NO_xRed = Target NO_x reduction efficiency (decimal fraction)

CF = Capacity factor (decimal fraction)

size = Boiler capacity (MMBtu/hr)

100 = Conversion factors

The total variable O&M costs are then calculated from:

$$\text{VO\&M (\$/yr)} = \text{Catalyst replacement and disposal cost (\$/yr)} + \text{other VO\&M cost (\$/yr)} \quad (B.28)$$

APPENDIX B

PARAMETER SETTINGS FOR CALPUFF AND CALMET

Table B-1. IWAQM Phase II Calpuff Parameter Settings Used in the Refined Regional Haze Analysis

Numbe	Input Group Description	Variable	Seq	Description	Default Value	Calpuff Input Screen	Modeled Value
1	Run Control	NMETDAT	1	Number of CALMET data files for run	1	Run Info	6
1		METRUN	2	Do we run all periods (1) or a subset (0)?	0	Run Info	0
1		IBYR	3	Beginning year	User Defined	Run Info	90
1		IBMO	4	Beginning month	User Defined	Run Info	1
1		IBDY	5	Beginning day	User Defined	Run Info	6
1		IBHR	6	Beginning hour	User Defined	Run Info	0
1		IRLG	6	Length of run (hours)	User Defined	Run Info	Bi-Monthly
1		NSPEC	7	Number of species modeled (for MESOPUFF II chemistry)	5	Species	6
1		NSE	8	Number of species emitted	3	Species	3
1		ITEST	9		2		2
1		MRESTART	10	Restart options (0 = no restart) allows splitting runs into smaller segments	0	Run Info	0
1		NRESPD	11		0		0
1		METFM	12	Format of input meteorology (1 = CALMET, 2 = ISC)	1	Met/Land Use	1
1		AVET	13	Averaging time lateral dispersion parameters (minutes)	60	Dispersion	60
1		PGTIME	14	PG Averaging Time (minutes)	60		60
2	Tech Options	MGAUSS	1	Near-field vertical distribution (1 = Gaussian)	1	Dispersion-Adv	1
2		MCTADJ	2	Terrain adjustments to plume path (3 = Plume path)	3	Terrain Effects	3
2		MCTSG	3	Do we have subgrid hills? (0 = No) allows CTDM-like treatment for subgrid scale hills	0	Terrain Effects	0
2		MSLUG	4	Near-field puff treatment (0 = No slugs)	0	Dispersion	0
2		MTRANS	5	Model transitional plume rise? (1 = Yes)	1	Plume Rise	1
2		MTIP	6	Treat stack tip downwash? (1 = Yes)	1	Plume Rise	1
2		MSHEAR	7	Treat vertical wind shear? (0 = No)	0	Plume Rise	0
2		MSPLIT	8	Allow puffs to split? (0 = No)	0	Dispersion-Adv	0
2		MCHEM	9	MESOPUFF-II Chemistry? (1 = Yes)	1	Chem Transform	1
2		MWET	10	Model wet deposition? (1 = Yes)	1	Deposition	1
2		MDRY	11	Model dry deposition? (1 = Yes)	1	Deposition	1
2		MDISP	12	Method for dispersion coefficients (3 = PG & MP)	3	Dispersion	4
2		MTURBVW	13	Turbulence characterization? (Only if MDISP = 1 or 5)	3	Dispersion	0
2		MDISP2	14	Backup coefficients (Only if MDISP = 1 or 5)	3	Dispersion	4
2		MROUGH	15	Adjust PG for surface roughness? (0 = No)	0	Dispersion	0
2		MPARTL	16	Model partial plume penetration? (0 = No)	1	Plume Rise	1
2		MTINV	17	Elevated inversion strength (0 = compute from data)	0	Plume Rise	0
2		MPDF	18	Use PDF for convective dispersion? (0 = No)	0	Dispersion	0
2		MSGTIBL	19	Use TIBL module? (0 = No) allows treatment of subgrid scale coastal areas	0	Met/Land Use	0
2		MREG	20	Regulatory default checks? (1 = Yes)	1	Run Info	0
3	Species List	CSPECn		Names of species modeled (for MESOPUFF II must be SO_2-SO_4-NO_X-HNO_3-NO_3, PM_{10}, CO)	User Defined	Species	ALL 7
3		Specie Groups		Grouping of species if any	User Defined	Species	NA
3		Specie Names		Manner species will be modeled	User Defined	Species	
4	Grid Control	NX	1	Number of east-west grids of input meteorology	User Defined	Grid Settings	90
4		NY	2	Number of north-south grids of input meteorology	User Defined	Grid Settings	94
4		NZ	3	Number of vertical layers of input meteorology	User Defined	Grid Settings	9
4		DGRIDKM	4	Meteorology grid spacing (km)	User Defined	Grid Settings	5

Table B-1. IWAQM Phase II Calpuff Parameter Settings Used in the Refined Regional Haze Analysis

Number	Input Group Description	Variable	Seq	Description	Default Value	Calpuff Input Screen	Modeled Value
4		ZFACE	5	Vertical cell face heights of input meteorology	User Defined	Grid Settings	9 values
4		XORIGKM	6	Southwest corner (east-west) of input User	Defined meteorology	Grid Settings	250
4		YORIGIM	7	Southwest corner (north-south) of input User	Defined meteorology	Grid Settings	2628
4		IUTMZN	8	UTM zone	User Defined	Grid Settings	17
4		XLAT	9	Latitude of center of meteorology domain	User Defined	Grid Settings	26
4		XLONG	10	Longitude of center of meteorology domain	User Defined	Grid Settings	81
4		XTZ	11	Base time zone of input meteorology	User Defined	Grid Settings	5
4		IBCOMP	12	Southwest X-index of computational domain	User Defined	Grid Settings	1
4		JBCOMP	13	Southwest Y-index of computational domain	User Defined	Grid Settings	1
4		IECOMP	14	Northeast X-index of computational domain	User Defined	Grid Settings	90
4		JECOMP	15	Northeast Y-index of computational domain	User Defined	Grid Settings	94
4		LSAMP	16	Use gridded receptors? (T = Yes)	F	Receptors	F
4		IBSAMP	17	Southwest X-index of receptor grid	User Defined	Receptors	0
4		JBSAMP	18	Southwest Y-index of receptor grid	User Defined	Receptors	0
4		IESAMP	19	Northeast X-index of receptor grid	User Defined	Receptors	90
4		JESAMP	20	Northeast Y-index of receptor grid	User Defined	Receptors	94
4		MESHDN	21	Gridded recpetor spacing = DGRIDKM/MESHDN	1	Receptors	1
5	Output Options	ICON	1	Output concentrations? (1 = Yes)	1	Output	1
5		IDRY	2	Output dry deposition flux? (1 = Yes)	1	Output	0
5		IWET	3	Output west deposition flux? (1 = Yes)	1	Output	0
5		IVIS	4	Output RH for visibility calculations (1 = Yes)	1	Output	1
5		LCOMPRS	5	Use compression option in output? (T = Yes)	T	Output	T
5		ICPRT	6	Print concentrations? (0 = No)	0	Output	0
5		IDPRT	7	Print dry deposition fluxes (0 = No)	0	Output	0
5		IWPRT	8	Print wet deposition fluxes (0 = No)	0	Output	0
5		ICFRQ	9	Concentration print interval (1 = hourly)	1	Output	24
5		IDFRQ	10	Dry deposition flux print interval (1 = hourly)	1	Output	1
5		IWFRQ	11	West deposition flux print interval (1 = hourly)	1	Output	1
5		IPRTU	12	Print output units (1 = g/m**3; g/m**2/s; 3 = g/m3, ug/m2/s)	1	Output	3
5		IMESG	13	Status messages to screen? (1 = Yes)	1	Output	1
5		LDEBUG	14	Turn on debug tracking? (F = No)	F	Output	F
5		NPFDEB	15	(Number of puffs to track)	(1)		1
5		NN1	16	(Met. Period to start output)	(1)		1
5		NN2	17	(Met. Period to end output)	(10)		10
7	Dry Dep Chem	Dry Gas Dep		Chemical parameters of gaseous deposition species	User Defined	Deposition	NO_x, HNO_3 SO_2
8	Dry Dep Size	Dry Part. Dep		Chemical parameters of particulate deposition species	User Defined	Deposition	SO_4, NO_3 PM_{10}
9	Dry Dep Misc	RCUTR	1	Reference cuticle resistance (s/cm)	30	Deposition-Adv	30
9		RGR	2	Reference ground resistance (s/cm)	10	Deposition-Adv	10
9		REACTR	3	Reference reactivity	8	Deposition-Adv	8
9		NINT	4	Number of particle-size intervals	9	Deposition-Adv	9

Table B-1. IWAQM Phase II Calpuff Parameter Settings Used in the Refined Regional Haze Analysis

Numbe	Input Group Description	Variable	Seq	Description	Default Value	Calpuff Input Screen	Modeled Value
9		IVEG	5	Vegetative state (1 = active and unstressed)	1	Deposition-Adv	1
10	Wet Dep	Wet Dep		Wet deposition parameters	User Defined	Deposition	Var
11	Chemistry	MOZ	1	Ozone background? (0 = constant background value; 1 = read from ozone.dat)	1	Chem Transform	0
11		BCKO3	2	Ozone default (ppb) (Use only for missing data)	80	Chem Transform	80
11		BCKNH3	3	Ammonia background (ppb)	10	Chem Transform	10
11		RNITE1	4	Nighttime SO2 loss rate (%/hr)	0.2	Chem Transform	0.2
11		RNITE2	5	Nighttime NOx loss rate (%/hr)	2	Chem Transform	2
11		RNITE3	6	Nighttime HNO3 loss rate (%/hr)	2	Chem Transform	2
12	Dispersion	SYTDEP	1	Horizontal size (m) to switch to time dependence	550	Dispersion	550
12		MHFTSZ	2	Use Heffter for vertical dispersion? (0 = No)	0	Dispersion	0
12		JSUP	3	PG Stability class above mixed layer	5	Met/Land Use-Adv	5
12		CONK1	4	Stable dispersion constant (Eq 2.7-3)	0.01	Deposition-Adv	0.01
12		CONK2	5	Neutral dispersion constant (Eq 2.7-4)	0.1	Deposition-Adv	0.1
12		TBD	6	Transition for downwash algorithms (0.5 = ISC)	0.5	Dispersion-Adv	0.5
12		IURB1	7	Beginning urban landuse type	10	Met/Land Use	10
12		IURB2	8	Ending urban landuse type	19	Met/Land Use	19
12		ILANDUIN	9	Land use type (20 = Unirrigated agricultural land)	(20)	Met/Land Use	20
12		ZOIN	10	Roughness length (m)	(0.25)	Met/Land Use	0.25
12		XLAIIN	11	Leaf area index	(3)	Met/Land Use	3
12		ELEVIN	12	Met. Station elevation (m above MSL)	(0)	Met/Land Use	0
12		XLATIN	13	Met. Station North latitude (degrees)	(-999)	Met/Land Use	-999
12		XLONIN	14	Met. Station West longitude (degrees)	(-999)	Met/Land Use	-999
12		ANEMHT	15	Anemometer height of ISC meteorological data (m)	(10)	Met/Land Use	NA
12		ISIGMAV	16	Lateral turbulence (Not used with ISC meteorology)	(1)	Dispersion	NA
12		IMIXCTDM	17	Mixing heights (Not used with ISC meteorology)	(1)	Met/Land Use	NA
12		XMXLEN	18	Maximum slug length in units of DGRIDKM	1	Dispersion-Adv	1
12		XSAMLEN	19	Maximum puff travel distance per sampling step (units of DGRIDKM)	1	Dispersion-Adv	1
12		MXNEW	20	Maximum number of puffs per hour	99	Dispersion-Adv	99
12		MXSAM	21	Maximum sampling steps per hour	99	Dispersion-Adv	99
12		NCOUNT	22	Iterations when computing Transport Wind (Calmet & Profile Winds)	(2)	Met/Land Use-Adv	2
12		SYMIN	23	Minimum lateral dispersion of new puff (m)	1	Dispersion-Adv	1
12		SZMIN	24	Minimum vertical dispersion of new puff (m)	1	Dispersion-Adv	1
12		SVMIN	25	Array of minimum lateral turbulence (m/s)	6 * 0.50	Dispersion-Adv	6*0.50
12		SWMIN	26	Array of minimum vertical turbulence (m/s)	0.20,0.12,0.08,0.06,0.03,0.016	Dispersion-Adv	SAME
12		CDIV (1), (2)	27	Divergence criterion for dw/dz (1/s)	0.01 (0.0,0.0)	Met/Land Use-Adv	0.0,0.0
12		WSCALM	28	Minimum non-calm wind speed (m/s)	0.5	Met/Land Use	0.5
12		XMAXZI	29	Maximum mixing height (m)	3000	Met/Land Use-Adv	3000
12		XMINZI	30	Minimum mixing height (m)	50	Met/Land Use-Adv	50
12		WSCAT	31	Upper bounds 1st 5 wind speed classes (m/s)	1.54,3.09,5.14,8. 23,10.8	Met/Land Use-Adv	SAME
12		PLX0	32	Wind speed power-law exponents	0.07,0.07,0.10,0.15,0.35,0.55	Met/Land Use	SAME
12		PTGO	33	Potential temperature gradients PG E and F (deg/km)	0.020,0.035	Met/Land Use-Adv	SAME
12		PPC	34	Plume path coefficients (only if MCTADJ = 3)	0.5,0.5,0.5,0.5,0.35,0.35	Terrain Effects	SAME

Table B-1. IWAQM Phase II Calpuff Parameter Settings Used in the Refined Regional Haze Analysis

Numbe	Input Group Description	Variable	Seq	Description	Default Value	Calpuff Input Screen	Modeled Value
12		SL2PF	35	Maximum Sy/puff length	10	Dispersion-Adv	10
12		NSPLIT	36	Number of puffs when puffs split	3	Dispersion-Adv	3
12		IRESPLIT	37	Hours when puff are eligible to split	User Defined	Dispersion-Adv	HR 17=1
12		ZISPLIT	38	Previous hour's mixing height(minimum)(m)	100	Dispersion-Adv	100
12		ROLDMAX	39	Previous Max mix ht/current mix ht ratio must be less then this value for puff to split	0.25	Dispersion-Adv	0.25
12		EPSSLUG	40	Convergence criterion for slug sampling integration	1.00E-04	Dispersion-Adv	1.0E-04
12		EPSAREA	41	Convergence criterion for area source integration	1.00E-06	Dispersion-Adv	1.0E-06
13	Point Source	NPT1	1	Number of point sources	User Defined	Sources: Point	1
13		IPTU	2	Units of emission rates (1 = g/s)	1	Sources: Point	1
13		NSPT1	3	Number of point source-species combinations	0	Sources: Point	0
13		NPT2	4	Number of point sources with fully variable emission rates	0	Sources: Point	0
13		Point Sources		Point sources characteristics	User Defined	Sources: Point	VAR
14	Area Source	Area Sources		Area sources characteristics	User Defined	Sources: Area	NA
15	Line Source	Line Sources		Buoyant lines source characteristics	User Defined	Sources: Line	NA
16	Volume Source	NVL1		Number of volume sources	User Defined		0
		IVLU		Units for volume source (1 = g/s)	User Defined		1
		NSVL1		Number of volume sources with emission scaling factors	0		1
17	Receptors	NREC		Number of user defined receptors	User Defined	Receptors	126
17		Receptor Data		Location and elevation (MSL) of receptors	User Defined	Receptors	VAR

Legend

DEPOS.	Vith Deposition
DEFAULT	Uses defaults
VAR	Variable Input
NA	Not Applicable
SAME	Same as recommended

Table B-2. IWAQM Phase II CALMET Option Settings Used for Refined Regional Haze Analysis

Variable	Description	Default Value	Modeled Value
GEO.DAT	Name of Geophysical data file	GEO.DAT	GEO.DAT
SURF.DAT	Name of Surface data file	SURF.DAT	SURF.DAT
PRECIP.DAT	Name of Precipitation data file	PRECIP.DAT	PRECIP.DAT
NUSTA	Number of upper air data sites	User Defined	3
Upn.DAT	Names of NUSTA upper air data files	Upn.DAT	UP1..UP5.DAT
NOWSTA	Number of Overwater met stations	User Defines	0
IBYR	Beginning year	User Defines	90
IBMO	Beginning month	User Defines	1
IBDY	Beginning day	User Defines	6
IBHR	Beginning hour	User Defines	0
IBTZ	Base time zone	User Defines	5
IRLG	Number of hours to simulate	User Defines	quarterly
IRTYPE	Output file type to create (must be 1 for CALPUFF)	1	1
LCALGRD	Are w-components and temperature needed?	T	T
NX	Number of east-west grid cells	User Defines	95
NY	Number of north-south grid cells	User Defines	60
DGRIDKM	Grid spacing	User Defines	5
XORIGKM	Southwest grid cell X coordinate	User Defines	452
YORIGKM	Southwest grid cell Y coordinate	User Defines	3236
XLAT0	Southwest grid cell latitude	User Defines	29.25
YLON0	Southwest grid cell longitude	User Defines	87.50
IUTMZN	UTM Zone	User Defines	16
LLCONF	When using Lambert Conformal map coordinates, roate winds from true north to map north?	F	F
XLAT1	Latitude of 1st standard parallel	30	30
XLAT2	Latitude of 2nd standard parallel	60	60
RLON0	Longitude used if LLCONF = T	90	NA
RLAT0	Latitude used in LLCONF = T	40	NA
NZ	Number of vertical layers	User Defines	8
ZFACE	Vertical cell face heights (NZ+1 values)	User Defines	9
LSAVE	Save met.data fields in an unformatted file?	T	T
INFORMO	Format of unformatted file (1 for CALPUFF)	1	1
NSSTA	Number of stations in SURF.DAT file	User Defines	8
NPSTA	Number of stations in PRECIP.DAT	User Defines	57
ICLOUD	Is cloud data to be input as gridded fields? (0 = No)	0	0
IFORMS	Format of surface data (2 = formatted)	2	2
IFORMP	Format of precipitation data (2 = formatted)	2	2
IFORMC	Format of cloud data (2 = formatted)	2	0
IWFCOD	Generate winds by diagnostic wind module? (1 = Yes)	1	1
IFRADJ	Adjust winds using Froude number effects? (1 = Yes)	1	1
IKINE	Adjust winds using kinematic effects? (1 = Yes)	0	0
IOBR	Use O'Brien procedure for vertical winds? (0 = No)	0	0
ISLOPE	Compute slope flows? (1 = Yes)	1	1

Table B-2. IWAQM Phase II CALMET Option Settings Used for Refined Regional Haze Analysis

Variable	Description	Default Value	Modeled Value
IEXTRP	Extrapolate surface winds to upper layers? (-4 = use similarity theory and ignore layer 1 of upper air station data)	-4	-4
ICALM	Extrapolate surface calms to upper layers? (0 = No)	0	0
BIAS	Surface/upper-air weighting factors (NZ values)	NZ*0	8*0
IPROG	Using prognostic or MM-FDDA data? (0 = No)	4	4
LVARY	Use varying radius to develop surface winds?	F	F
RMAX1	Max surface over-land extrapoolation radius (km)	User Defines	40
RMAX2	Max aloft over-land extrapolation radius (km)	User Defines	100
RMAX3	Maximum over-water extrapolation radius (km)	User Defines	100
RMIN	Minimum extrapolation radius (km)	0.1	0.1
RMIN2	Distance (km) around an upper air site where veritcal extrapolation is excluded (Set to -1 if IEXTRP = +/-4)	4	4
TERRAD	Radius of influence of terrain features (km)	User Defines	10
R1	Relative weight at surface of Step 1 field and obs	User Defines	60
R2	Relative weight aloft of Step 1 field and obs	User Defines	100
DIVLIM	Maximum acceptable divergence	5.00E-06	5.00E-06
NITER	Max number of passes in divergence minimization	50	50
NSMTH	Number of passes in smoothing (NZ values)	2,4*(NZ-1)	2,4*(NZ-1)
NINTR2	Max number of stations for interpolations (NZ values)	99	99
CRITFN	Critical Froude number	1	1
ALPHA	Empirical factor triggering kinematic effects	0.1	0.1
IDIOPT1	Compute temperatures from observations (0 = True)	0	0
ISURFT	Surface station to use for surface temperature (between 1 and NSSTA)	User Defines	2
IDIOPT2	Compute domain-average lapse rates? (0 = True)	0	0
IUPT	Station for lapse rates (between 1 and NUSTA)	User Defines	3
ZUPT	Depth of domain-average lapse rate (m)	200	200
IDIOPT3	Compute internally initial guess winds? (0 = True)	0	0
IUPWND	Upper air station for domain winds (-1 = 1/r**2 interpolation of all stations)	-1	-1
ZUPWND	Bottom and top of layer for 1st guess winds (m)	1, 1000	1, 5000
IDIOPT4	Read surface winds from SURF.DAT? (0 = True)	0	0
IDIOPT5	Read aloft winds from UPn.DAT? (0 = True)	0	0
CONSTB	Neutral mixing height B constant	1.41	1.41
CONSTE	Convective mixing height E constant	0.15	0.15
CONSTN	Stable mixing height N constant	2400	2400
CONSTW	Over-water mixing height W constant	0.16	0.16
FCORIOL	Absolute value of Coriolis parameter	1.00E-04	1.00E-04
IAVEXZI	Spatial averaging of mixing heights? (1 = True)	1	1
MNMDAV	Max averaging radius (number of grid cells)	1	3
HAFANG	Half-angle for looking upwind (degrees)	30	30
ILEVZI	Layer to use in upwind averaging (between 1 and NZ)	1	1

Table B-2. IWAQM Phase II CALMET Option Settings Used for Refined Regional Haze Analysis

Variable	Description	Default Value	Modeled Value
DPTMIN	Minimum capping potential temperature lapse rate	0.001	0.001
DZZI	Depth for comuting capping lapse rate (m)	200	200
ZIMIN	Minimum over-land mixing height (m)	50	50
ZIMAX	Maximum over-land mixing height (m)	3000	3000
ZIMINW	Minimum over-water mixing height (m)	50	50
ZIMAXW	Maximum over-water mixing height (m)	3000	3000
IRAD	Form of temperature interpolation (1 = 1/r)	1	1
TRADKM	Radius of temperature interpolation (km)	500	500
NUMTS	max number of station in temperature interpolations	5	5
IAVET	Conduct spatial averaging of temperature? (1 = True)	1	1
TGDEFB	Default over-water mixed layer lapse rate (K/m)	-0.0098	-0.0098
TGDEFA	Default over-water capping lapse rate (K/m)	-0.0045	-0.0045
JWAT1	Beginning landuse type defining water	999	50
JWAT2	Ending landuse type defining water	999	50
NFLAGP	Method for precipitation interpolation (2 = 1/r**2)	2	2
SIGMAP	Precip radius for interpolations (km)	100	100
CUTP	Minimum cut off precip rate (mm/hr)	0.01	0.01
SSn	NSSTA input records for surface stations	User Defines	8
USn	NUSTA input records for upper-air stations	User Defines	3
PSn	NPSTA input records for precipation stations	User Defines	57

Legend

DEFAULT	Uses defaults
VAR	Variable Input
NA	Not Applicable
SAME	Same as recommended

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Golder Associates

March 22, 2001

0037593

Florida Department of Environmental Protection
Division of Air Resources Management
2600 Blair Stone Road MS 5500
Tallahassee, FL 32399-2400

RECEIVED

MAR 23 2001

BUREAU OF AIR REGULATION

Attention: Mr. A. A. Linero, P.E.
New Source Review Section

RE: OKEELANTA CORPORATION
FACILITY ID NO. 0990005
BOILER NO. 16 CONVERSION TO NATURAL GAS

Dear Mr. Linero:

Okeelanta Corporation is requesting a PSD permit for the conversion of existing Boiler No. 16 to a dual fuel natural gas/fuel oil-fired boiler. Okeelanta is also requesting operation up to 8,760 hr/yr. Attached are six (6) copies of the PSD permit application, along with the application fee of $7,500.

Thank you for your consideration of this request. Please call if there are any questions.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

DB/jkw

cc: Matt Capone
J. Kahn
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C. Holladay
J. Goldman, SED
D. Graziani, PBCHD
EPA
NPS

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Golder Associates

March 22, 2001

0037593

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RECEIVED

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cc: Matt Capone
J. Kaiser

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