Revised PSD Permit Application for Boiler Nos. 4 and 5

Osceola Farms Company

August 30, 2004

Golder Associates

REVISED
PSD PERMIT APPLICATION
BOILER NOS. 4 AND 5
OSCEOLA FARMS COMPANY

Prepared for:

Osceola Farms Company
U.S. 98 and Hatton Highway
Pahokee, FL 33476

Prepared by:

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

August 2004
0437543

DISTRIBUTION:
7 Copies – FDEP
1 Copy – Palm Beach County Health Unit
4 Copies – Osceola Farms Company
1 Copy – Golder Associates Inc.

PERMIT APPLICATION FORM

Department of Environmental Protection

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SEP 01 2004

BUREAU OF AIR REGULATION

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:

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

Air Operation Permit – Use this form to apply for:

- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Osceola Farms Company**	
2. Site Name: **Osceola Farms Sugar Mill**	
3. Facility Identification Number: **0990019**	
4. Facility Location...: Street Address or Other Locator: **US 98 & Hatton Highway** City: **Pahokee** County: **Palm Beach** Zip Code: **33476**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Paco Farinas**
2. Application Contact Mailing Address... Organization/Firm: **Osceola Farms Company** Street Address: **US 98 & Hatton Highway** City: **Pahokee** State: **FL** Zip Code: **33476**
3. Application Contact Telephone Numbers... Telephone: **(561) 924-7156** ext. Fax: **(561) 924-3246**
4. Application Contact Email Address:

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Project Number(s):	0990019-006-AC
3. PSD Number (if applicable):	PSD-FL-337
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

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

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

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

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

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

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

Application Comment

Converting Boiler Nos. 4 and 5 from cell-type boilers to inclined-grate type boilers. Projected date of construction commencement: March, 2005. Projected date of construction completion: March, 2007. See PSD Report.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
004	Boiler No. 4	AC1A	
005	Boiler No. 5	AC1A	

Application Processing Fee

Check one: ☒ Attached - Amount: $ 7,500 ☐ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name : **Carlos Rionda, Vice President and General Manager**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Osceola Farms Company** Street Address: **U.S. 98 & Hatton Highway** City: **Pahokee** State: **FL** Zip Code: **33476**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(561) 924-7156** ext. Fax: **(561) 924-3246**
4.	Owner/Authorized Representative Email Address:
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* [signature] 8/27/04 Signature Date

Application Responsible Official Certification

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

1. Application Responsible Official Name:

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

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

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

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

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

   Signature   Date

APPLICATION INFORMATION

Professional Engineer Certification

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

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

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

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

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

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

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

David A. Buff

Signature

8/30/04

Date

(seal)

* Attach any exception to certification statement.

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

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **544.7** North (km) **2967.3**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **26 / 49 / 45** Longitude (DD/MM/SS) **80 / 33 / 00**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **20**	6. Facility SIC(s): **2061**
7. Facility Comment : **The Osceola Farms Company (OFC) sugar mill consists of all operations necessary to manufacture raw sugar from sugarcane. This includes five bagasse/oil-fired boilers, a lime silo, and a sugar mill and boiling house. In reference to the OFC sugar mill facility flow diagram (Attachment OF-FI-C3), based on historical agricultural crop seasons, an average of 16,200 tons of cane can be processed per crop day. The actual operating rate of the mill will vary from season to season depending on agricultural, market, and weather conditions.**			

Facility Contact

1. Facility Contact Name: **Carlos Rionda, Vice President and General Manager**
2. Facility Contact Mailing Address... Organization/Firm: **Osceola Farms Company** Street Address: **U.S. 98 and Hatton Highway** City: **Pahokee** State: **FL** Zip Code: **33476**
3. Facility Contact Telephone Numbers: Telephone: **(561) 924-7156** ext. Fax: **(561) 924-3246**
4. Facility Contact Email Address:

Facility Primary Responsible Official

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

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

FACILITY INFORMATION

Facility Regulatory Classifications

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

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **See Attachment OF-FI-A12.**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM	A	
PM_{10}	A	
SO_2	A	
NO_x	A	
CO	A	
VOC	A	
PB	A	
HAPs	A	

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

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

Additional Requirements for Air Construction Permit Applications

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

FACILITY INFORMATION

Additional Requirements for FESOP Applications

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

Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

ATTACHMENT OF-FI-A12

FACILITY REGULATORY CLASSIFICATION COMMENT

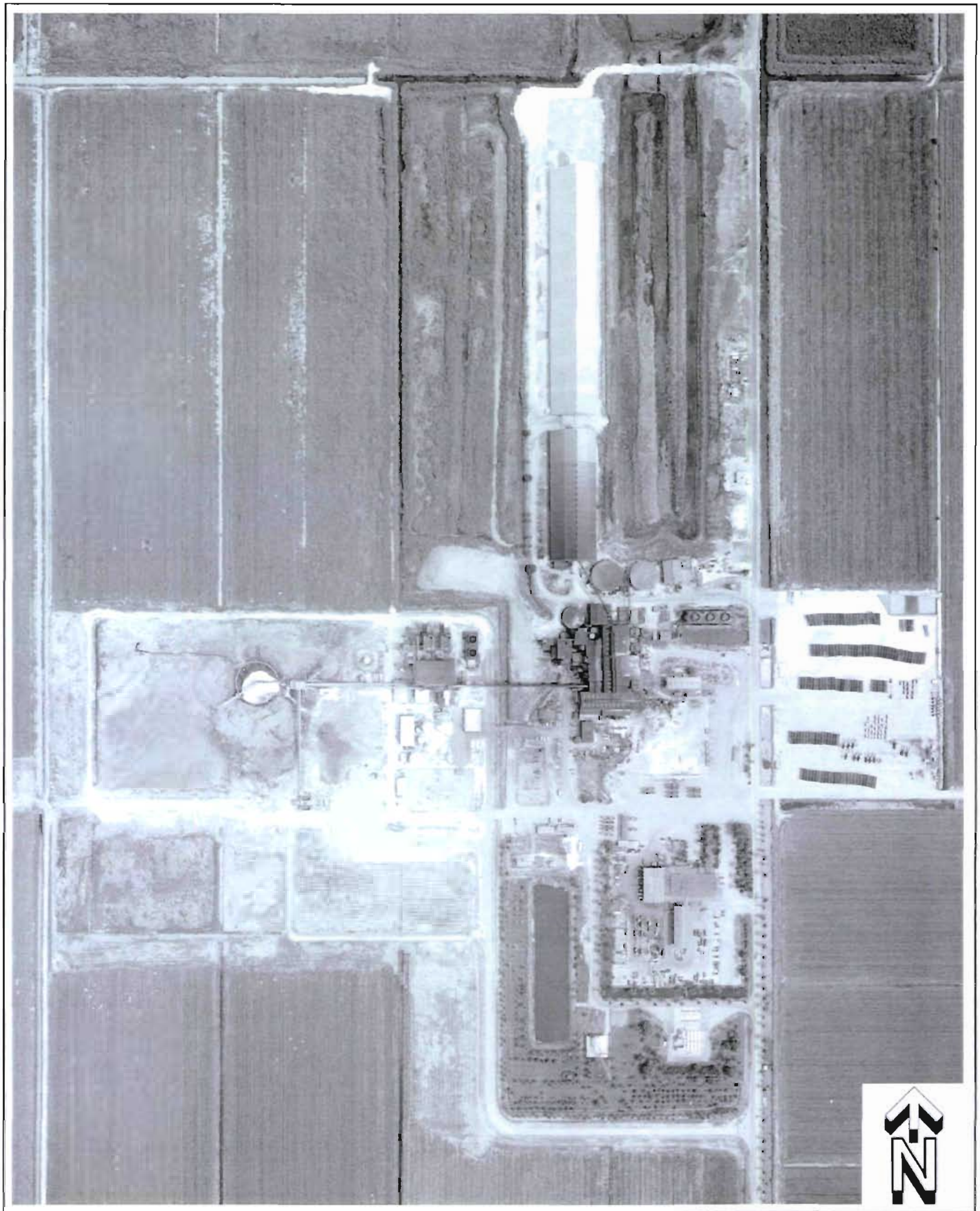
ATTACHMENT OF-FI-A12

FACILITY REGULATORY CLASSIFICATION COMMENT

At this time, it is unclear whether Osceola Farms Company will be classified as major for HAPs. Osceola Farms has no emissions test data indicating significant HAP emissions from its boilers. Recent sugar industry test data indicates that there are HAPs emissions from sugar industry bagasse fired boilers. However, these emissions data may not be representative of Osceola Farms HAPs emissions. Nevertheless, Osceola Farms has checked the box signifying a major source of HAPs.

ATTACHMENT OF-FI-C1

FACILITY PLOT PLAN



Attachment OF-FI-C1a
Facility Plot Plan – Osceola Farms Company

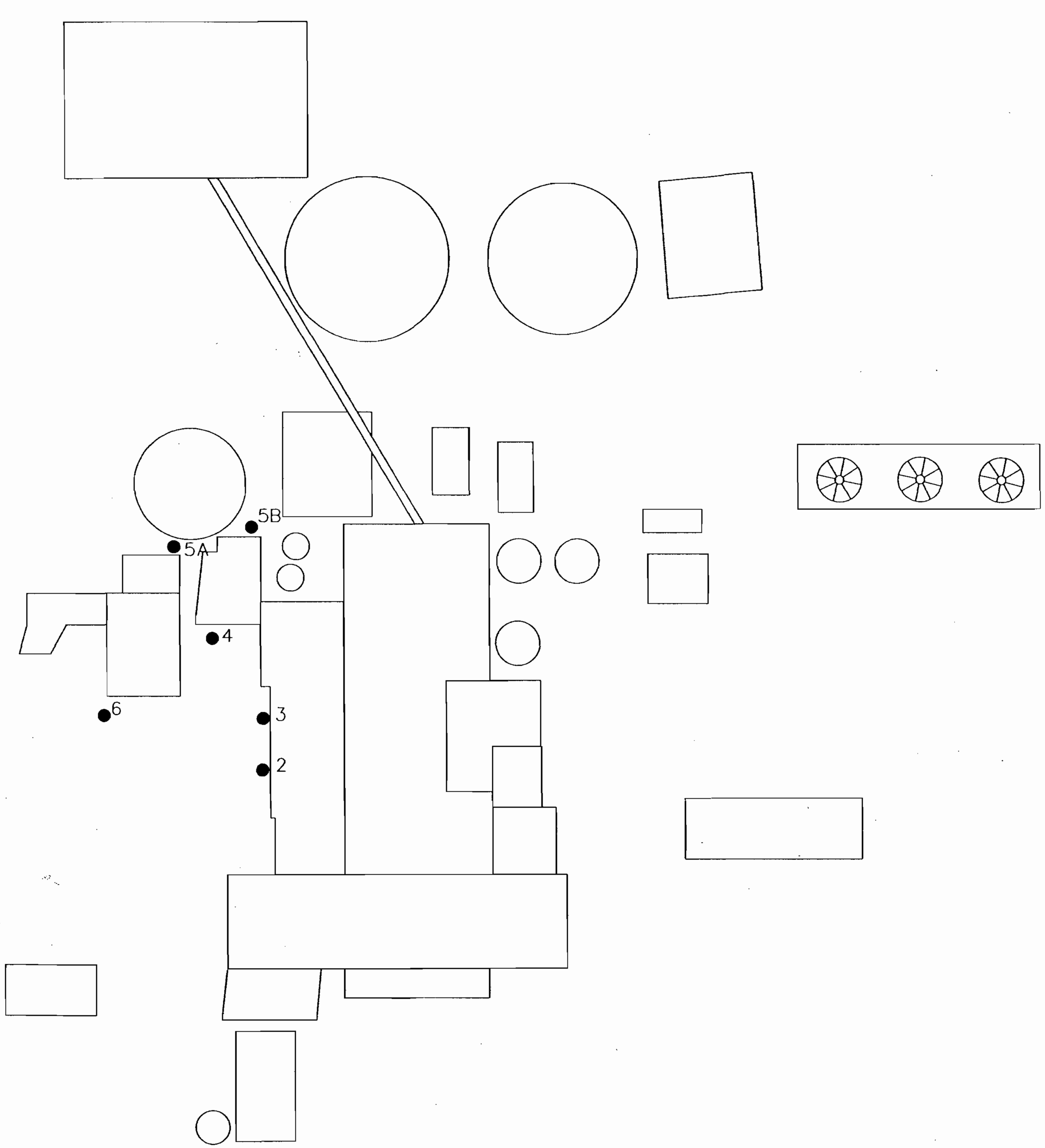
Golder Associates

Source: Photogrammetric Technologies, Inc., 2002; Golder, 2003.

Attachment OF-FI-C1b
Facility Plot Plan – Osceola Farms Company

Source: Photogrammetric Technologies, Inc., 2002; Golder, 2003.

Golder Associates



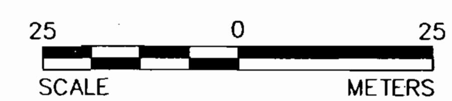
LEGEND

—	BUILDING
● 2	BOILER STACK

NOTES

REFERENCES

1.) PHOTOGRAMMETRIC TECHNOLOGIES, INC., 2002



PROJECT

OSCEOLA FARMS COMPANY

TITLE

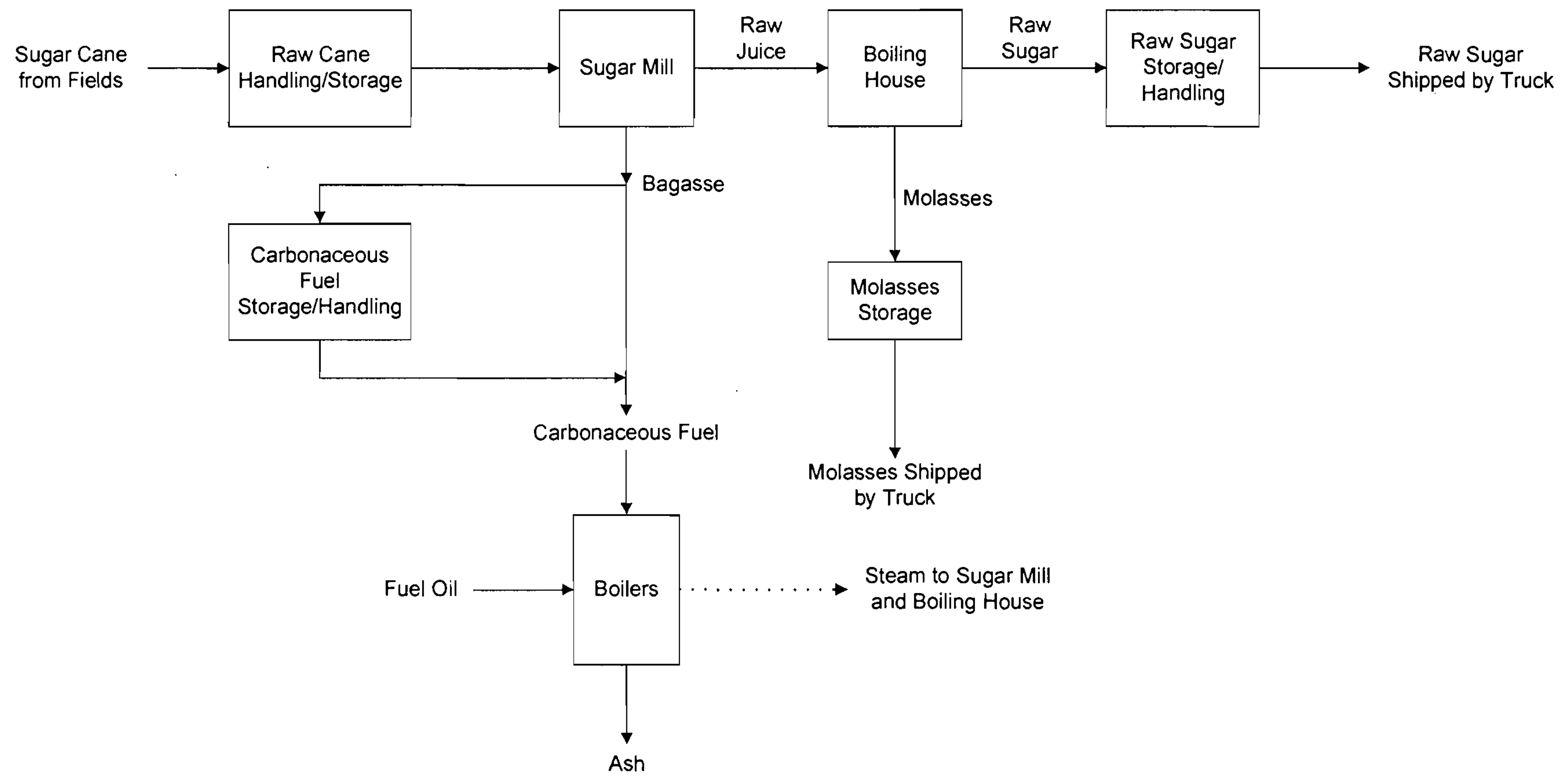
ATTACHMENT OF-FI-C1c
FACILITY PLOT PLAN

Golder Associates
Gainesville, Florida

PROJECT No.		0237630	FILE No.	OF-FI--C2c.Dwg
DESIGN			SCALE AS SHOWN	REV.
CADD	AB	8/5/2003	No. 1	
CHECK				
REVIEW	DB	8/5/2003		

ATTACHMENT OF-FI-C2

PROCESS FLOW DIAGRAM



Attachment OFC-FI-C2
Sugar Manufacturing
Process Flow Diagram
Osceola Farms Company
Pahokee, Florida

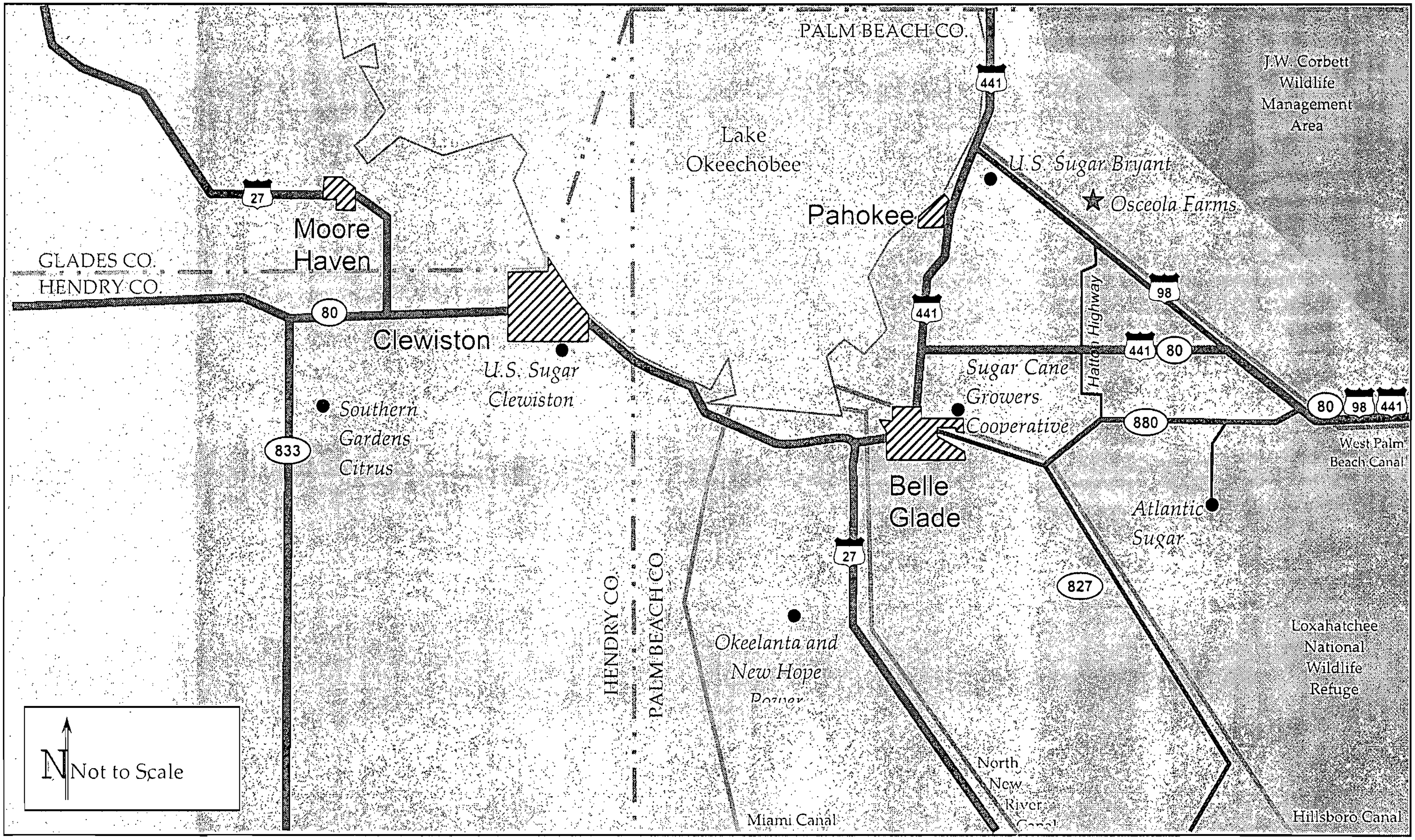
Process Flow Legend
Solid/Liquid ——→
Steam ·······→

Filename: 0437543/4/4.4/OF-FI-2.VSD
Date: 08/19/04

Golder Associates

ATTACHMENT OF-FI-CC1

AREA MAP SHOWING FACILITY LOCATION



Attachment OF-FI-CC1
Location of Palm Beach Power Corp.

Source: Golder Associates Inc., 2002.

Golder Associates

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
   Boiler No. 4

3. Emissions Unit Identification Number: **004**

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

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
   Cell type boiler to be converted to an inclined grate type boiler. Fired with bagasse and No. 6 fuel oil. Hours of operation limited to 3,840 hours per season. Crop season may extend from October 1 to April 30.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

   Two Joy Turbulaire Type D-48 Wet Impingement Scrubbers.

   Mist Eliminators (one per scrubber).

2. Control Device or Method Code(s): **002, 015**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:			
2. Maximum Production Rate: 170,000 lb/hr steam			
3. Maximum Heat Input Rate: 336.6 million Btu/hr			
4. Maximum Incineration Rate:	pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 23 weeks/year		7 days/week 3,840 hours/year
6. Operating Capacity/Schedule Comment: Maximum heat input rates: Bagasse – 336.6 MMBtu/hr (3 hr); No. 6 Fuel Oil – 82.5 MMBtu/hr; maximum 24-hr average heat input from bagasse is 316.8 MMBtu/hr, equivalent to 160,000 lb/hr steam.			

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Boiler No. 4**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **90** feet	7. Exit Diameter: **6.0** feet
8. Exit Temperature: **154** °F	9. Actual Volumetric Flow Rate: **134,650** 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 Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters are for maximum 3-hr bagasse firing rate, based on last 2 years of stack tests. See Table 2-6 of the PSD report for other averaging times.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **External Combustion Boilers, Industrial, Bagasse, All Boiler Sizes.**		
2. Source Classification Code (SCC): **1-02-011-01**	3. SCC Units: **Tons Burned (All Solid Fuels)**	
4. Maximum Hourly Rate: **46.75**	5. Maximum Annual Rate: **158,400**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.1 (dry)**	8. Maximum % Ash: **8.4 (dry)**	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment: **Maximum hourly rate based on 336.6 MMBtu/hr and a wet bagasse heating value of 3,600 Btu/lb. Maximum annual rate based on 297.0 MMBtu/hr and 3,840 hr/yr.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **External Combustion Boilers, Industrial, Residual Oil, Grade 6 Oil.**		
2. Source Classification Code (SCC): **1-02-004-01**	3. SCC Units: **1000 Gallons Burned (All Liquid Fuels)**	
4. Maximum Hourly Rate: **0.543**	5. Maximum Annual Rate: **800**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.0**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **152**
10. Segment Comment: **Maximum hourly rate based on 82.5 MMBtu/hr and 1.0% sulfur No. 6 oil.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	002	015	EL
PM_{10}	002	015	NS
SO_2			EL
NO_x			EL
CO			EL
VOC			EL
PB			NS
SAM			NS
FL			NS
HAPs			NS

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **50.49** lb/hour **85.54** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.15 lb/MMBtu** Reference: **Proposed Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **0.15 lb/MMBtu x 336.6 MMBtu/hr = 50.49 lb/hr** **1,140,480 MMBtu/yr x 0.15 lb/MMBtu ÷ 2,000 lb/ton = 85.54 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on bagasse firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.15 lb/MMBtu**	4. Equivalent Allowable Emissions: **50.49** lb/hour **85.54** tons/year
5. Method of Compliance: **Annual Stack testing using EPA Method 5.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on bagasse firing.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **8.25** lb/hour **6.08** tons/year
5. Method of Compliance: **Fuel Analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.410. Based on No. 6 fuel oil firing @ 82.5 MMBtu/hr and 800,000 gal/yr (121,600 MMBtu/yr).**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **47.12** lb/hour **79.55** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.14 lb/MMBtu** Reference: **Test Data**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **0.14 lb/MMBtu x 336.6 MMBtu/hr = 47.12 lb/hr** **1,140,480 MMBtu/yr x 0.14 lb/MMBtu ÷ 2,000 lb/ton = 79.55 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on bagasse firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 100.47 lb/hour 93.37 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 157 S lb/1,000 gal Reference: AP-42	7. Emissions Method Code: 0
8. Calculation of Emissions: Fuel oil = 542.8 gal/hr x 157 (1.0) lb/1,000 gal = 85.22 lb/hr Bagasse (remainder of heat input) = 254.1 MMBtu/hr x 0.06 lb/MMBtu = 15.25 lb/hr Total = 85.22 + 15.25 = 100.47 lb/hr	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Emission factor based on fuel oil firing.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.0% S fuel oil**	4. Equivalent Allowable Emissions: **85.2** lb/hour **62.80** tons/year
5. Method of Compliance: **Fuel analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 800,000 gal/yr max fuel oil usage.**	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **93.38** lb/hour **134.08** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.22 lb/MMBtu (bagasse)** Reference: **Proposed BACT Limit**	7. Emissions Method Code: **0**

8. Calculation of Emissions:

Short term:
Fuel oil = 542.8 gal/hr x 55 lb/1,000 gal = 29.85 lb/hr
Bagasse (remainder of heat input) = 254.1 MMBtu/hr x 0.25 lb/MMBtu = 63.53 lb/hr
Total = 29.85 + 63.53 = 93.38 lb/hr

Annual average:
See Table 2-4 of PSD report.

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Annual average emission factor for bagasse is 0.22 lb/MMBtu; short-term is 0.25 lb/MMBtu.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.22 lb/MMBtu (Bagasse, annual avg.)**	4. Equivalent Allowable Emissions: **84.15** lb/hour **125.45** tons/year
5. Method of Compliance: **EPA Method 7 or 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on bagasse firing. Short-term limit of 0.25 lb/MMBtu.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2,019.6** lb/hour **2,109.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **3.70 lb/MMBtu (bagasse)** Reference: **Proposed Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **3-hr average: 6.0 lb/MMBtu x 336.6 MMBtu/hr = 2,019.6 lb/hr** **Annual: 1,140,480 MMBtu/yr x 3.70 lb/MMBtu ÷ 2,000 lb/ton = 2,109.9 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on bagasse firing. Emission factor for fuel oil is 5 lb/1,000 gal.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3.70 lb/MMBtu, annual average**	4. Equivalent Allowable Emissions: **2,019.6** lb/hour **2,109.9** tons/year
5. Method of Compliance: **EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on bagasse firing. Short-term emissions based on 6.0 lb/MMBtu.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **134.6** lb/hour **228.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.40 lb/MMBtu (bagasse)** Reference: **Proposed BACT Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **0.40 lb/ MMBtu x 336.6 MMBtu/hr = 134.6 lb/hr** **1,140,480 MMBtu/yr x 0.40 lb/MMBtu ÷ 2,000 lb/ton = 228.1 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on bagasse firing. Emission factor for fuel oil is 0.28 lb/1,000 gal.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.40 lb/MMBtu**	4. Equivalent Allowable Emissions: **134.6** lb/hour **228.1** tons/year
5. Method of Compliance: **EPA Methods 25A/18. VOC reported as methane.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **Lead**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0082** lb/hour **0.014** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2.44×10^{-5} lb/MMBtu (bagasse)** Reference: **Similar Stack Test Data**	7. Emissions Method Code: **0**

8. Calculation of Emissions:

2.44×10^{-5} lb/MMBtu x 336.6 MMBtu/hr = 0.0082 lb/hr

1,140,480 MMBtu/yr x 2.44×10^{-5} lb/MMBtu ÷ 2,000 lb/ton = 0.014 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Based on bagasse firing. Emission factor for fuel oil is 1.51×10^{-3} lb/1,000 gal.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **6.15** lb/hour **5.72** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **9.62 lb/1000 gal** Reference: **AP-42**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **See PSD Report.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on fuel oil and bagasse firing. Emission factor for bagasse is 0.0037 lb/MMBtu.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **Flourides**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.141** lb/hour **0.239** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **$4.18x10^{-4}$ lb/MMBtu (bagasse)** Reference: **Similar Stack Test Data**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **$4.18x10^{-4}$ lb/MMBtu x 336.6 MMBtu/hr = 0.141 lb/hr** **1,140,480 MMBtu/yr x $4.18x10^{-4}$ lb/MMBtu ÷ 2000 lb/ton = 0.239 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on bagasse firing. Emission factor for fuel oil is $3.73x10^{-2}$ lb/1000 gal.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **H114 (Mercury)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.00268** lb/hour **0.0045** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **7.95×10^{-6} lb/MMBtu (bagasse)** Reference: **Based on Test Data**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **7.95×10^{-6} lb/MMBtu x 336.6 MMBtu/hr = 0.00268 lb/hr** **1,140,480 MMBtu/yr x 7.95×10^{-6} lb/MMBtu ÷ 2000 lb/ton = 0.0045 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on bagasse firing. Emission factor for fuel oil is 1.13×10^{-4} lb/1,000 gal.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE30**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **30** % Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **DEP Method 9**	
5. Visible Emissions Comment: **Rule 62-296.410(1)(b)**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 3

1. Parameter Code: **PRS**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **Custom Design** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Existing permit condition requires monitoring of scrubber pressure drop. Parameter monitored to ensure proper operation of scrubber.**	

Continuous Monitoring System: Continuous Monitor 2 of 3

1. Parameter Code: **Water pressure**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **Custom Design** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Existing permit condition requires monitoring of scrubber inlet water pressure. Parameter monitored to ensure proper operation of the scrubber.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 3 of 3

1. Parameter Code: FLOW	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: Badger Model Number: 258HW	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Continuous Monitor Comment: Existing permit condition requires monitoring of oil flow.	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: OF-EU1-I1 ☐ Previously Submitted, Date ____
2.	Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: OF-EU1-I2 ☐ Previously Submitted, Date ____
3.	Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: OF-EU1-I3 ☐ Previously Submitted, Date ____
4.	Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: OF-EU1-I4 ☐ Previously Submitted, Date ____ ☐ Not Applicable (construction application)
5.	Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable
6.	Compliance Demonstration Reports/Records ☐ Attached, Document ID: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ Previously Submitted, Date: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ To be Submitted, Date (if known): ____ Test Date(s)/Pollutant(s) Tested: ____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7.	Other Information Required by Rule or Statute ☒ Attached, Document ID: OF-EU1-I7 ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

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

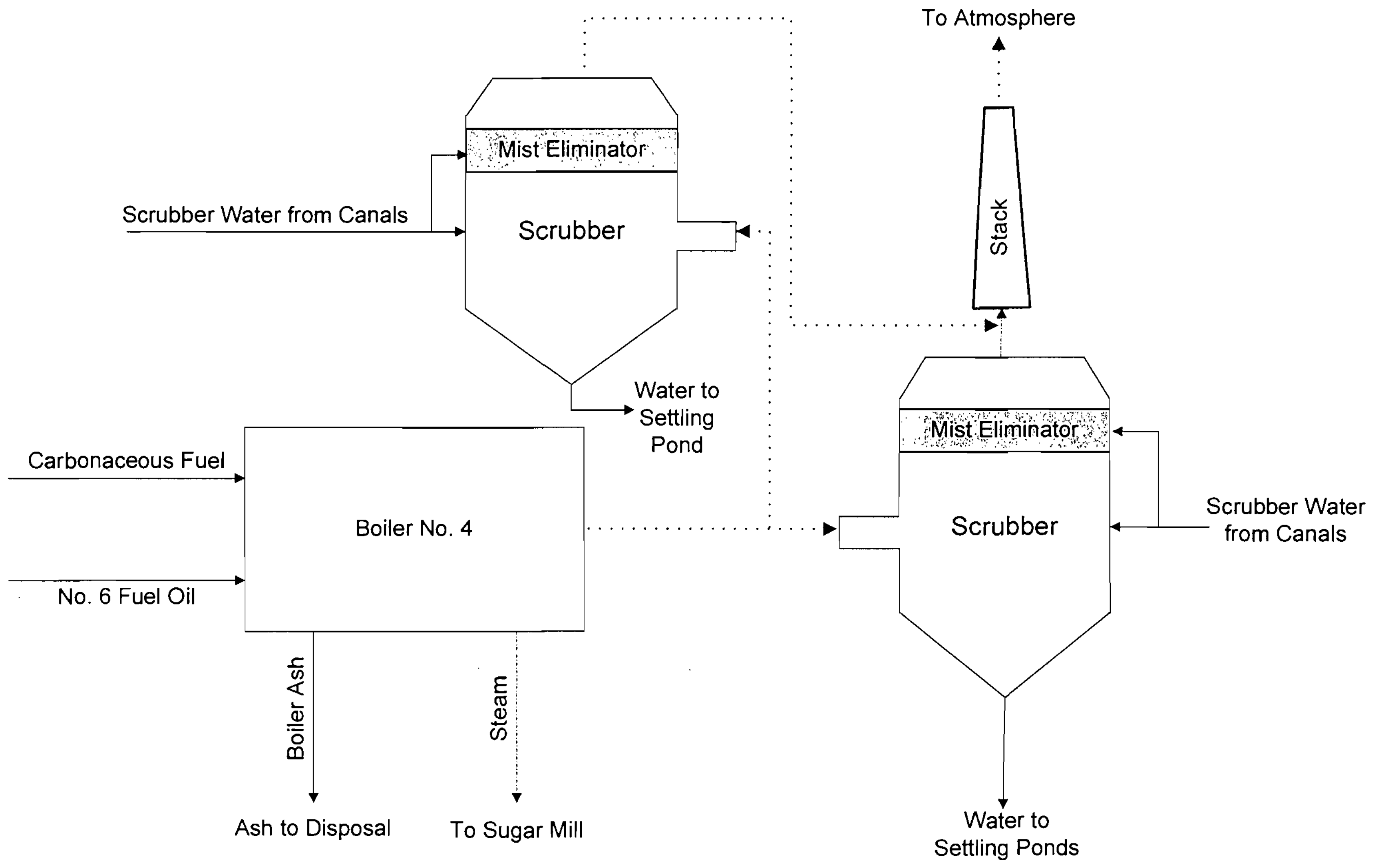
Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

ATTACHMENT OF-EU1-I1

PROCESS FLOW DIAGRAM



Attachment OF-EU1-I1
Boiler No. 4 - Process Flow Diagram
Osceola Farms Company - Pahokee, FL

Process Flow Legend

Solid/Liquid	→
Steam	→
Gas	→

Golder Associates

ATTACHMENT OF-EU1-I2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT OF-EU1-I2

FUEL ANALYSIS SPECIFICATION FOR OSCEOLA FARMS COMPANY BOILER NO. 4

Parameter	Carbonaceous Fuel Bagasse [a]	No. 6 Fuel Oil [b] (1.0% max S)
Density (lb/gal)	--	8.33
Approximate Heating Value (Btu/lb)	3,600 [c]	0
Approximate Heating Value (Btu/gal)	--	152,000 [d]
Ultimate Analysis (dry basis):		
Carbon	49%	84.7%
Hydrogen	5.8%	11.0%
Nitrogen	0.36%	0.18%
Oxygen	41.9%	0.38%
Sulfur	0.03% - 0.10%	1.0%
Ash/Inorganic	0.9% - 8.4%	0.02%
Moisture	50% - 55%	--

Note: All values represent average fuel characteristics.

Footnotes:

[a] Source: sugar industry fuel analysis averages.

[b] Source: Perry's Chemical Engineers' Handbook. Sixth Edition.

[c] Minimum value on a wet basis for bagasse.

[d] Source: Coastal Fuels Marketing, Inc. typical fuel analysis.

ATTACHMENT OF-EU1-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

ATTACHMENT OF-EU1-I3

CONTROL EQUIPMENT PARAMETERS FOR BOILER NO. 4 WET SCRUBBER

Boiler No. 4			
Manufacturer and Model No.			2 Joy Turbulaire Wet Impingement Scrubbers Type D-48
Outlet Gas Temp (°F)			160 [a]
Outlet Gas Flow Rate (acfm)			70,000 [a]
Pressure Drop Across Device (inches of H_2O) Min/Max			5 / 10
Scrubbant Flow Rate (gal/min) - Minimum			300
Scrubbant Supply Pressure (psi) - Normal/Minimum			60 / 40
Max Permitted Heat Inputs (MMBtu/hr) : Carbonaceous fuel			336.6
Max Carbonaceous fuel Consumption (lb carbonaceous fuel/hr)			93,500 [b]
Uncontrolled Particulate Emission Rate (lb particulates/ton carbonaceous fuel)			15.6 [c]
Permitted Particulate Emission Rate (lb particulates/MMBtu)			0.15 [d]
Pollutants	Inlet Loading lb/hr	Outlet Loading lb/hr	Control Efficiency (%)
Particulate Matter	729.3	50.5	93

Note: Scrubber parameters represent typical values.

[a] Value based on stack test data for each scrubber.
[b] Calculated using an average bagasse heating value of 3,600 Btu/lb and the permitted heat input rate.
[c] AP-42 table 1.8-2 uncontrolled emission factor of 15.6 lb/ton.
[d] Proposed permit limit.

Sample calculations:

Inlet loading (lb/hr) = (uncontrolled particulate emission rate X max carbonaceous fuel consumption) / 2000 lb/ton

Outlet loading (lb/hr) = (permitted particulate emission rate X max permitted heat input rate)

Control efficiency (%) = [(inlet loading - outlet loading) / inlet loading] X 100

ATTACHMENT OF-EU1-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT OF-EU1-I4
STARTUP AND SHUTDOWN PROCEDURES
BOILER NO. 4

During startup and shutdown of the boilers, excess PM, opacity, NO_X, and VOC emissions for more than 2 hours in a 24-hour period are possible. Pursuant to Rule 62-210.700(1), FAC, the following procedures and precautions are taken to minimize the magnitude and duration of excess emissions during startup and shutdown of Boiler No. 4. Boiler room foreman and operating personnel have received proper training on emissions control procedures.

Boiler Startup Procedure:

If Boiler No. 5 is not available, then boiler start up operations begin with the firing of Boiler No. 4. If this is the case, firewood instead of bagasse is used to initiate boiler combustion.

1. The furnace cells are loaded with adequate amounts of firewood or bagasse depending on boiler startup sequence.
2. Approximately 30 gallons of diesel fuel are poured on top of the pile of firewood or bagasse.
3. The scrubber is turned on by opening the water valves to the scrubber spray nozzles and supplying the desired water flow rate and pressure.
4. The soaked firewood or bagasse is ignited.
5. Bagasse is retrofed to the boiler as required to raise and maintain the pressure in Boiler No. 4.

Boiler No. 4 will be an inclined grate type boiler. Grate type boilers require 7 to 12 hours from the first fire to the normal working pressure. The warm-up period must be gradual to avoid damaging the boiler. Excess emissions could occur at times during the start up period.

Boiler Shutdown Procedure:

1. The feeding of fuel to the boiler is discontinued and the remaining fuel is allowed to burn completely.
2. Any steam remaining in the boiler drum is released.
3. The scrubber water pumps are stopped.

Excess Emissions:

The emission limits in lb/MMBtu for one or more pollutants could be exceeded at times during periods of startup and shutdown. However, due to the reduced firing rate during this time, it is not likely that the maximum mass emissions allowed for the boiler would be exceeded.

ATTACHMENT OF-EU1-I7

EMISSIONS UNIT REGULATIONS

ATTACHMENT OF-EU1-I7
EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

62-296.410(2)(b) – Carbonaceous Fuel Burning Equipment

62-296.410(3) – Carbonaceous Fuel Burning Equipment

62-297.310 – General Compliance Test Requirements

62-297.310(1) – General Compliance Test Requirements

62-297.310(2)(b) – General Compliance Test Requirements

62-297.310(3) – General Compliance Test Requirements

62-297.310(4) – General Compliance Test Requirements

62-297.310(5) – General Compliance Test Requirements

62-297.310(6) – General Compliance Test Requirements

62-297.310(7)(a)3. – General Compliance Test Requirements

62-297.310(7)(a)4. – General Compliance Test Requirements

62-297.310(7)(a)5. – General Compliance Test Requirements

62-297.310(7)(a)9. – General Compliance Test Requirements

62-297.310(7)(a)10. – General Compliance Test Requirements

62-297.310(8) – General Compliance Test Requirements

62-297.401(5) – EPA Test Method 5

62-297.401(7) – EPA Test Method 7

62-297.401(7)(e) – EPA Test Method 7E

62-297.401(9) – EPA Test Method 9

62-297.401(10) – EPA Test Method 10

62-297.401(18) – EPA Test Method 18

62-297.401(25)(a) – EPA Test Method 25A

62-297.440(1)(b) – Supplementary Test Procedures

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

Emissions Unit Description and Status

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

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

2. Description of Emissions Unit Addressed in this Section:
Boiler No. 5

3. Emissions Unit Identification Number: **005**

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

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
Cell type boiler to be converted to an inclined grate type boiler. Fired with bagasse and No. 6 fuel oil. Hours of operation limited to 3,840 hours per season. Crop season may extend from October 1 to April 30.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

Two Joy Turbulaire Type D-48 Wet Impingement Scrubbers.

Mist Eliminators (one per scrubber).

2. Control Device or Method Code(s): **002, 015**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:			
2. Maximum Production Rate: **170,000 lb/hr steam**			
3. Maximum Heat Input Rate: **336.6** million Btu/hr			
4. Maximum Incineration Rate:	pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	**24** hours/day **23** weeks/year		**7** days/week **3,840** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input rates: Bagasse – 336.6 MMBtu/hr (3 hr); No. 6 Fuel Oil – 82.5 MMBtu/hr; maximum 24-hr average heat input from bagasse is 316.8 MMBtu/hr, equivalent to 160,000 lb/hr steam.**			

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Boiler No. 5**	2. Emission Point Type Code: **3**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **90** feet	7. Exit Diameter: **5.0** feet
8. Exit Temperature: **154** °F	9. Actual Volumetric Flow Rate: **153,002** 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 Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Stack parameters are for maximum 3-hr bagasse firing rate, based on last 2 years of stack tests. There are two identical stacks at 76,501 acfm each. See Table 2-6 of PSD report for other averaging times.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **External Combustion Boilers, Industrial, Bagasse, All Boiler Sizes.**		
2. Source Classification Code (SCC): **1-02-011-01**	3. SCC Units: **Tons Burned (All Solid Fuels)**	
4. Maximum Hourly Rate: **46.75**	5. Maximum Annual Rate: **158,400**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.1 (dry)**	8. Maximum % Ash: **8.4 (dry)**	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment: **Maximum hourly rate based on 336.6 MMBtu/hr and a wet bagasse heating value of 3,600 Btu/lb. Maximum annual rate based on 297.0 MMBtu/hr and 3,840 hr/yr.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **External Combustion Boilers, Industrial, Residual Oil, Grade 6 Oil.**		
2. Source Classification Code (SCC): **1-02-004-01**	3. SCC Units: **1000 Gallons Burned (All Liquid Fuels)**	
4. Maximum Hourly Rate: **0.543**	5. Maximum Annual Rate: **800**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.0**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **152**
10. Segment Comment: **Maximum hourly rate based on 82.5 MMBtu/hr and 1.0% sulfur No. 6 oil.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	002	015	EL
PM_{10}	002	015	NS
SO_2			EL
NO_x			EL
CO			EL
VOC			EL
PB			NS
SAM			NS
FL			NS
HAPs			NS

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **50.49** lb/hour **85.54** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.15 lb/MMBtu** Reference: **Proposed Limit**	7. Emissions Method Code: **0**

8. Calculation of Emissions:

0.15 lb/MMBtu x 336.6 MMBtu/hr = 50.49 lb/hr

1,140,480 MMBtu/yr x 0.15 lb/MMBtu ÷ 2,000 lb/ton = 85.54 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Based on bagasse firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.15 lb/MMBtu**	4. Equivalent Allowable Emissions: **50.49** lb/hour **85.54** tons/year
5. Method of Compliance: **Annual Stack testing using EPA Method 5.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on bagasse firing.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **8.25** lb/hour **6.08** tons/year
5. Method of Compliance: **Fuel Analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.410. Based on No. 6 fuel oil firing @ 82.5 MMBtu/hr and 800,000 gal/yr (121,600 MMBtu/yr).**	

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **47.12** lb/hour **79.55** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.14 lb/MMBtu** Reference: **Test Data**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **0.14 lb/MMBtu x 336.6 MMBtu/hr = 47.12 lb/hr** **1,140,480 MMBtu/yr x 0.14 lb/MMBtu ÷ 2,000 lb/ton = 79.55 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on bagasse firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 100.47 lb/hour 93.37 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 157 S lb/1,000 gal Reference: AP-42	7. Emissions Method Code: 0
8. Calculation of Emissions: Fuel oil = 542.8 gal/hr x 157 (1.0) lb/1,000 gal = 85.22 lb/hr Bagasse (remainder of heat input) = 254.1 MMBtu/hr x 0.06 lb/MMBtu = 15.25 lb/hr Total = 85.22 + 15.25 = 100.47 lb/hr	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Emission factor based on fuel oil firing.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.0% S fuel oil**	4. Equivalent Allowable Emissions: **85.2** lb/hour **62.80** tons/year
5. Method of Compliance: **Fuel analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 800,000 gal/yr max fuel oil usage.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **93.38** lb/hour **134.08** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.22 lb/MMBtu (bagasse)** Reference: **Proposed BACT Limit**	7. Emissions Method Code: **0**

8. Calculation of Emissions:

Short term:
Fuel oil = 542.8 gal/hr x 55 lb/1,000 gal = 29.85 lb/hr
Bagasse (remainder of heat input) = 254.1 MMBtu/hr x 0.25 lb/MMBtu = 63.53 lb/hr
Total = 29.85 + 63.53 = 93.38 lb/hr

Annual average:
See Table 2-4 of PSD report.

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Annual average emission factor for bagasse is 0.22 lb/MMBtu; short-term is 0.25 lb/MMBtu.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.22 lb/MMBtu (Bagasse, annual avg.)**	4. Equivalent Allowable Emissions: **84.15** lb/hour **125.45** tons/year
5. Method of Compliance: **EPA Method 7 or 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on bagasse firing. Short-term limit of 0.25 lb/MMBtu.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2,019.6** lb/hour **2,109.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **3.70 lb/MMBtu (bagasse)** Reference: **Proposed limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **3-hr average: 6.0 lb/MMBtu x 336.6 MMBtu/hr = 2,019.6 lb/hr** **Annual: 1,140,480 MMBtu/yr x 3.70 lb/MMBtu ÷ 2,000 lb/ton = 2,109.9 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on bagasse firing. Emission factor for fuel oil is 5 lb/1,000 gal.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3.70 lb/MMBtu, annual average**	4. Equivalent Allowable Emissions: **2,019.6** lb/hour **2,109.9** tons/year
5. Method of Compliance: **EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on bagasse firing. Short-term emissions based on 6.0 lb/MMBtu.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **134.6** lb/hour **228.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.40 lb/MMBtu (bagasse)** Reference: **Proposed BACT Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **0.40 lb/ MMBtu x 336.6 MMBtu/hr = 134.6 lb/hr** **1,140,480 MMBtu/yr x 0.40 lb/MMBtu ÷ 2,000 lb/ton = 228.1 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on bagasse firing. Emission factor for fuel oil is 0.28 lb/1,000 gal.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.40 lb/MMBtu**	4. Equivalent Allowable Emissions: **134.6** lb/hour **228.1** tons/year
5. Method of Compliance: **EPA Methods 25A/18. VOC reported as methane.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **Lead**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0082** lb/hour **0.014** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2.44×10^{-5} lb/MMBtu (bagasse)** Reference: **Similar Stack Test Data**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **2.44×10^{-5} lb/MMBtu x 336.6 MMBtu/hr = 0.0082 lb/hr** **1,140,480 MMBtu/yr x 2.44×10^{-5} lb/MMBtu ÷ 2,000 lb/ton = 0.014 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on bagasse firing. Emission factor for fuel oil is 1.51×10^{-3} lb/1,000 gal.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **6.15** lb/hour **5.72** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **9.62 lb/1000 gal** Reference: **AP-42**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **See PSD Report.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on fuel oil and bagasse firing. Emission factor for bagasse is 0.0037 lb/MMBtu.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **Flourides**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.141** lb/hour **0.239** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **4.18×10^{-4} lb/MMBtu (bagasse)** Reference: **Similar Stack Test Data**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **4.18×10^{-4} lb/MMBtu x 336.6 MMBtu/hr = 0.141 lb/hr** **1,140,480 MMBtu/yr x 4.18×10^{-4} lb/MMBtu ÷ 2000 lb/ton = 0.239 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on bagasse firing. Emission factor for fuel oil is 3.73×10^{-2} lb/1000 gal.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **H114 (Mercury)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.00268** lb/hour **0.0045** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **7.95×10^{-6} lb/MMBtu (bagasse)** Reference: **Based on Test Data**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **7.95×10^{-6} lb/MMBtu x 336.6 MMBtu/hr = 0.00268 lb/hr** **1,140,480 MMBtu/yr x 7.95×10^{-6} lb/MMBtu ÷ 2000 lb/ton = 0.0045 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on bagasse firing. Emission factor for fuel oil is 1.13×10^{-4} lb/1,000 gal.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE30**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **30** % Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **DEP Method 9**	
5. Visible Emissions Comment: **Rule 62-296.410(1)(b)**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 3

1. Parameter Code: **PRS**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **Custom Design** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Existing permit condition requires monitoring of scrubber pressure drop. Parameter monitored to ensure proper operation of scrubber.**	

Continuous Monitoring System: Continuous Monitor 2 of 3

1. Parameter Code: **Water pressure**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **Custom Design** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Existing permit condition requires monitoring of scrubber inlet water pressure. Parameter monitored to ensure proper operation of the scrubber.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 3 of 3

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Badger** Model Number: **258HW**	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Continuous Monitor Comment: **Existing permit condition requires monitoring of oil flow.**	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **OF-EU2-I1** ☐ Previously Submitted, Date ____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **OF-EU1-I2** ☐ Previously Submitted, Date ____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **OF-EU2-I3** ☐ Previously Submitted, Date ____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **OF-EU2-I4** ☐ Previously Submitted, Date ____ ☐ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records ☐ Attached, Document ID: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ Previously Submitted, Date: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ To be Submitted, Date (if known): ____ Test Date(s)/Pollutant(s) Tested: ____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute ☒ Attached, Document ID: **OF-EU2-I7** ☐ Not Applicable

EMISSIONS UNIT INFORMATION
Section [2] of [2]
Boiler No. 5

Additional Requirements for Air Construction Permit Applications

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

Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

EMISSIONS UNIT INFORMATION
Section [2] of [2]
Boiler No. 5

Additional Requirements for Air Construction Permit Applications

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

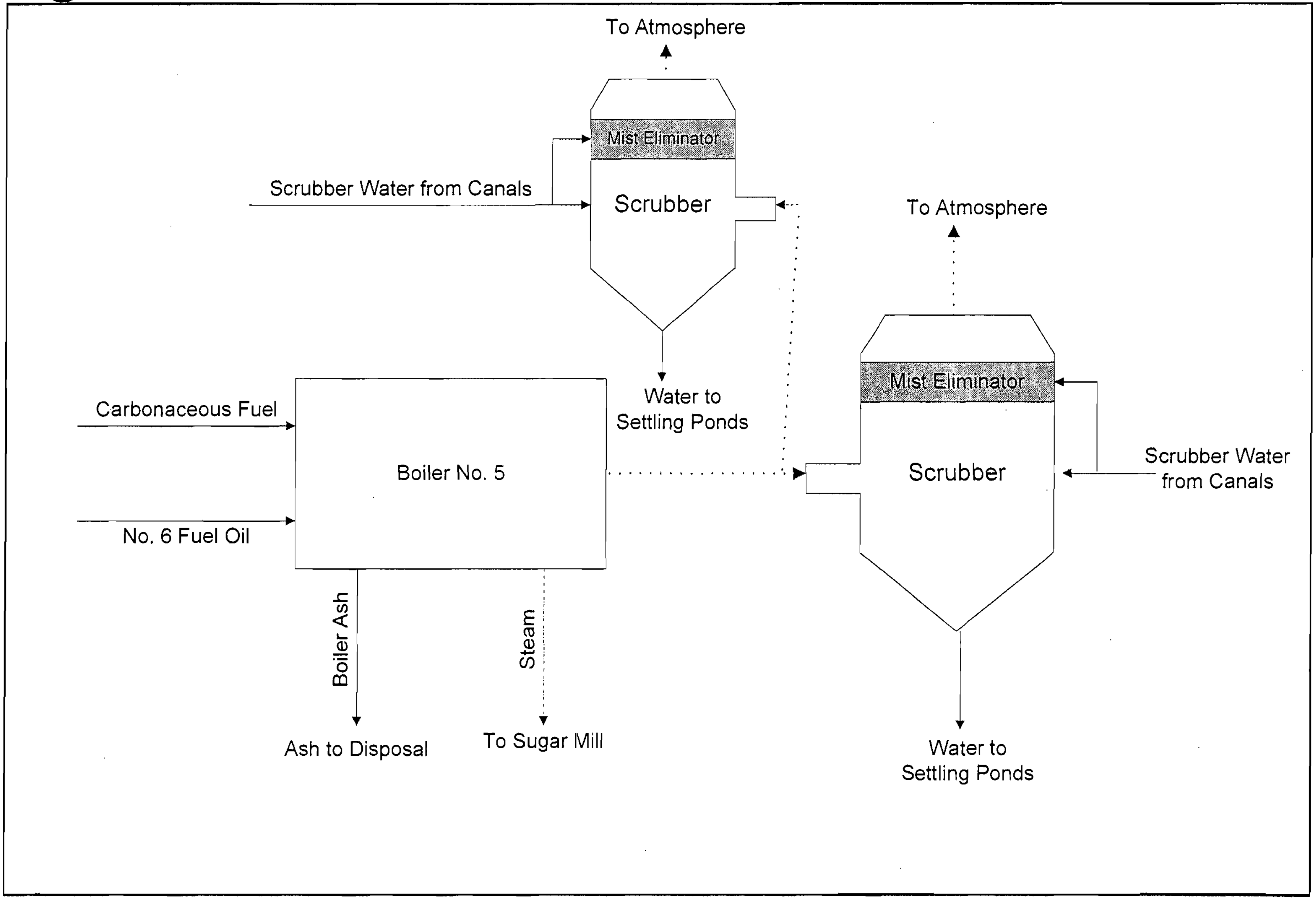
Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

ATTACHMENT OF-EU2-I1

PROCESS FLOW DIAGRAM



Attachment OF-EU2-I1
Boiler No. 5 - Process Flow Diagram
Osceola Farms Company - Pahokee, FL

Process Flow Legend
Solid/Liquid
Steam
Gas

Golder Associates

ATTACHMENT OF-EU2-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

ATTACHMENT OF-EU2-I3

CONTROL EQUIPMENT PARAMETERS FOR BOILER NO. 5 WET SCRUBBER

Boiler No. 5			
Manufacturer and Model No.		2 Joy Turbulaire Wet Impingement Scrubbers Type D-40	
Outlet Gas Temp (°F)			160 [a]
Outlet Gas Flow Rate (acfm)			76,500 [a]
Pressure Drop Across Device (inches of H_2O) Min/Max			5 / 10
Scrubbant Flow Rate (gal/min) - Minimum			300
Scrubbant Supply Pressure (psi) - Normal/Minimum			60 / 40
Max Permitted Heat Inputs (MMBtu/hr) : Carbonaceous fuel			336.6
Max Carbonaceous fuel Consumption (lb carbonaceous fuel/hr)			93,500 [b]
Uncontrolled Particulate Emission Rate (lb particulates/ton carbonaceous fuel)			15.6 [c]
Permitted Particulate Emission Rate (lb particulates/MMBtu)			0.15 [d]
Pollutants	Inlet Loading lb/hr	Outlet Loading lb/hr	Control Efficiency (%)
Particulate Matter	729.3	50.5	93

Note: Scrubber parameters represent typical values.

[a] For each scrubber and stack.
[b] Calculated using an average bagasse heating value of 3,600 Btu/lb and the permitted heat input rate.
[c] AP-42 table 1.8-2 uncontrolled emission factor of 15.6 lb/ton.
[d] Proposed permit limit.

Sample calculations:

Inlet loading (lb/hr) = (uncontrolled particulate emission rate X max carbonaceous fuel consumption) / 2000 lb/ton

Outlet loading (lb/hr) = (permitted particulate emission rate X max permitted heat input rate)

Control efficiency (%) = [(inlet loading - outlet loading) / inlet loading] X 100

ATTACHMENT OF-EU2-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT OF-EU2-I4
STARTUP AND SHUTDOWN PROCEDURES
BOILER NO. 5

During startup and shutdown of the boilers, excess PM, opacity, NO_X, and VOC emissions for more than 2 hours in a 24-hour period are possible. Pursuant to Rule 62-210.700(1), FAC, the following procedures and precautions are taken to minimize the magnitude and duration of excess emissions during startup and shutdown of Boiler No. 5. Boiler room foreman and operating personnel have received proper training on emissions control procedures.

Boiler Startup Procedure:

Boiler startup operations normally begin with the firing of Boiler No. 5. Since this boiler is usually the first boiler to startup boiler operations at the mill, firewood instead of bagasse is used to initiate boiler combustion.

1. The furnace cells are loaded with adequate amounts of firewood or bagasse depending on boiler startup sequence.
2. Approximately 30 gallons of diesel fuel are poured on top of the pile of firewood or bagasse.
3. The scrubber is turned on by opening the water valves to the scrubber spray nozzles and supplying the desired water flow rate and pressure.
4. The soaked bagasse is ignited.
5. Bagasse is retrofed to the boiler as required to raise and maintain the pressure in Boiler No. 5.

Boiler No. 5 will be an inclined grate type boiler. Grate type boilers require 7 to 12 hours from the first fire to the normal working pressure. The warm-up period must be gradual to avoid damaging the boiler. Excess emissions could occur at times during the start up period.

Boiler Shutdown Procedure:

1. The feeding of fuel to the boiler is discontinued and the remaining fuel is allowed to burn completely.
2. Any steam remaining in the boiler drum is released.
3. The scrubber water pumps are stopped.

Excess Emissions:

The emission limits in lb/MMBtu for one or more pollutants could be exceeded at times during periods of startup and shutdown. However, due to the reduced firing rate during this time, it is not likely that the maximum mass emissions allowed for the boiler would be exceeded.

ATTACHMENT OF-EU2-I7

EMISSIONS UNIT REGULATIONS

ATTACHMENT OF-EU2-I7
EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

62-296.410(2)(b) – Carbonaceous Fuel Burning Equipment

62-296.410(3) – Carbonaceous Fuel Burning Equipment

62-297.310 – General Compliance Test Requirements

62-297.310(1) – General Compliance Test Requirements

62-297.310(2)(b) – General Compliance Test Requirements

62-297.310(3) – General Compliance Test Requirements

62-297.310(4) – General Compliance Test Requirements

62-297.310(5) – General Compliance Test Requirements

62-297.310(6) – General Compliance Test Requirements

62-297.310(7)(a)3. – General Compliance Test Requirements

62-297.310(7)(a)4. – General Compliance Test Requirements

62-297.310(7)(a)5. – General Compliance Test Requirements

62-297.310(7)(a)9. – General Compliance Test Requirements

62-297.310(7)(a)10. – General Compliance Test Requirements

62-297.310(8) – General Compliance Test Requirements

62-297.401(5) – EPA Test Method 5

62-297.401(7) – EPA Test Method 7

62-297.401(7)(e) – EPA Test Method 7E

62-297.401(9) – EPA Test Method 9

62-297.401(10) – EPA Test Method 10

62-297.401(18) – EPA Test Method 18

62-297.401(25)(a) – EPA Test Method 25A

62-297.440(1)(b) – Supplementary Test Procedures

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1.0 INTRODUCTION AND EXECUTIVE SUMMARY

Osceola Farms Company (Osceola Farms) owns and operates a sugar mill located east of Pahokee, Palm Beach County, Florida. Osceola Farms is proposing to modify two of its bagasse-fired boilers (Boiler Nos. 4 and 5) at the Mill to improve the operation and reliability of these units to provide steam to the sugarcane processing operations. Boiler Nos. 4 and 5 are identical cell (horseshoe)-type boilers that fire bagasse as its primary fuel, with No. 6 fuel oil used for startup, shutdown, and as a supplementary fuel.

Boiler Nos. 4 and 5 will be converted to inclined-grate type boilers, utilizing water-cooled, pinhole grate design. The boilers will each be designed to produce 170,000 pounds per hour (lb/hr) steam as a 3-hour (hr) average, and 160,000 lb/hr steam as a daily 24-hr average. The boilers will operate up to 160 days per calendar year [3,840 hours per year (hr/yr)].

The conversion of Boiler Nos. 4 and 5 will allow the Mill to better utilize its turbo generators and make more efficient use of steam at the Mill. The turbo generators are used to make electricity for internal consumption. The increase in steam production afforded by the project will also allow a higher sugar Mill grinding rate. The average daily sugarcane grinding rate after the proposed project is implemented will be approximately 16,200 tons per crop day.

This application contains the technical information developed in accordance with Prevention of Significant Deterioration (PSD) regulations as promulgated by the U.S. Environmental Protection Agency (EPA) and implemented by 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, Osceola Farms requests that the FDEP issue a PSD construction permit for this project.

1.1 PSD REQUIREMENTS

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 the approved program of the FDEP. FDEP has adopted the EPA PSD regulations as Rule 62-212.400, Florida Administrative Code (F.A.C.).

The PSD applicability for the project is summarized in Table 1-1. 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), and
- Volatile organic compounds (VOC).

Palm Beach County has been designated as an attainment, maintenance, or unclassifiable area for all criteria pollutants. The County is also classified as a PSD Class II area for particulate matter with aerodynamic size less than 10 microns (PM_{10}), sulfur dioxide (SO_2), and nitrogen dioxide (NO_2). Therefore, the New Source Review (NSR) will follow PSD regulations pertaining to such designations.

1.2 BACT ANALYSIS

For the proposed modifications to Boiler Nos. 4 and 5, a BACT analysis was conducted for each pollutant for which the net increase exceeds the EPA/FDEP significance emission rate and, is therefore, subject to BACT review. The proposed BACT to control NO_x and VOC emissions from Boiler Nos. 4 and 5 will be good combustion practices (GCPs).

1.3 AIR QUALITY ANALYSIS

An air quality impact analysis was conducted for NO_x emission to determine if the proposed modification 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 Boiler Nos. 4 and 5 would not result in ambient concentrations above the AAQS or the PSD Class II and Class I allowable increments for NO_2. As a result, the project will not cause or contribute to any adverse impacts on air quality. Additional impacts due to the proposed project on soils, vegetation, visibility, growth, and air quality related values (AQRVs) in the nearest PSD Class I area were analyzed and found to be not adverse.

1.4 SUMMARY OF ANALYSIS

Results from the analyses presented in this PSD air permit application are the basis for 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 Ambient Air Quality Standards (NAAQS) will not be exceeded as a result of the operation of the proposed modification.
- Allowable PSD increments will not be exceeded as a result of the operation of the proposed modification.
- No adverse effects upon soils, vegetation, visibility or AQRVs in the PSD Class I area are predicted.

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

1.5 AIR PERMIT APPLICATION ORGANIZATION

This air permit application is divided into eight major sections, including this introduction and 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 state and federal air quality regulations applicable to the proposed project;
- Section 4.0 presents the ambient air monitoring analysis (pre-construction monitoring) required by PSD regulations;
- Section 5.0 presents the control technology review and BACT analysis;
- Section 6.0 presents a summary of the air modeling approach and results used in assessing compliance of the proposed project with AAQS, PSD increments, and good engineering practice (GEP) stack height regulations; and
- Section 7.0 provides the additional impact analyses for soils, vegetation, and visibility, and the AQRV analysis.

Table 1-1. PSD Source Applicability Analysis, Osceola Farms Boiler Nos. 4 and 5 Modification

Regulated Pollutant	Current Actual Emissions From Osceola Farms Boiler Nos. 4 and 5 (TPY)	Future Potential Emissions From Osceola Farms Boiler Nos. 4 and 5 (TPY)	Net Change In Emissions Due to Proposed Project (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Triggered?
Particulate (TSP)	134.86	150.00	15.14	25	No
Particulate (PM_{10})	125.45	139.50	14.05	15	No
Sulfur Dioxide	83.89	119.15	35.27	40	No
Nitrogen Oxides	158.16	228.62	70.46	40	Yes
Carbon Monoxide	3,610.59	3,700.00	89.41	100	No
VOC	155.81	400.00	244.19	40	Yes
Mercury	0.0064	0.0080	0.0016	0.1	No
Fluorides	0.34	0.42	0.07	3	No
Lead	0.020	0.024	0.005	0.6	No
Sulfuric Acid Mist	5.14	7.30	2.16	7	No

TPY = Tons per year
TSP = Total Suspended Particles
PM_{10} = Particulate Matter with aerodynamic diameter less than or equal to 10 microns
VOC = Volatile Organic Compounds

2.0 PROJECT DESCRIPTION

2.1 SITE DESCRIPTION

Osceola Farms owns and operates a raw sugar Mill located approximately 6 miles east of Pahokee, Palm Beach County, Florida. Osceola Farms is proposing to modify two of its bagasse-fired boilers (Boiler Nos. 4 and 5) at the Mill to provide a more efficient and reliable steam supply to the sugarcane processing operations.

The Osceola Farms sugar Mill receives sugarcane by truck from nearby cane fields and processes it into raw sugar. The cane is first cut into small pieces, and is then passed through a series of presses (Mills) where the sugar cane juices are squeezed from the cane. The fibrous byproduct material remaining is called bagasse, and is burned in on site steam boilers for fuel.

The cane juice is further processed and purified through a series of steps involving clarification, separation, evaporation, and crystallization. The final product is raw, unrefined sugar. The raw sugar is stored in a warehouse and then shipped offsite by truck to customers. Refer to Attachment OF-FI-C3 of the permit application form for a flow diagram of the overall sugar production process.

The total Osceola Farms Mill sugarcane processing rate during the last 10 years is shown in the table below:

Crop Season	Tons of Sugarcane Processed	Crop Season	Tons of Sugarcane Processed
2003/2004	2,270,455	1998/1999	1,989,651
2002/2003**	2,304,591	1997/1998	1,936,414
2001/2002	2,044,061	1996/1997	1,746,150
2000/2001**	2,025,452	1995/1996	1,895,328
1999/2000	1,736,926	1994/1995	1,705,419

**Florida Crystals Corporation production only.

The Osceola Farms Mill currently has five bagasse/oil-fired boilers (Boiler Nos. 2, 3, 4, 5, and 6), which provide steam to the sugar Mill. The primary fuel for all boilers is bagasse, while No. 6 fuel oil is used for startup, shutdown, malfunction, and as a supplemental fuel. For economic reasons, fuel oil burning is minimized to the extent possible.

All boilers have wet scrubbers for particulate matter (PM) control. Currently, all boilers are limited to 3,840 hr/yr annual operating hours, with operation restricted to October 2 through April 30.

Boiler Nos. 4 and 5 are similar cell (horseshoe) type boilers. Boiler No. 4, manufactured by Bigelow, was a new boiler installed at the Mill in 1965, while Boiler No. 5, manufactured by Alpha, was a new boiler installed in 1978. Neither boiler was required to go through PSD preconstruction review prior to construction, since the current PSD rules have only been in effect since 1980.

Boiler No. 4 is permitted for a steam production rate of 140,000 lb/hr steam (24-hr average), and Boiler No. 5 is permitted for 165,000 lb/hr steam (24-hr average). Both boilers currently have design steam operating conditions of 280 pounds per square inch gauge (psig) and 550-degrees Fahrenheit (°F). Engineering drawings of both boilers as they currently exist are provided in Appendix I.

Boiler Nos. 4 and 5 each have two scrubbers operating in parallel. The scrubbers are of the wet impingement type (Joy Turbulaire Type D-48 for Boiler No. 4, and Type D-40 for Boiler No. 5). Boiler No. 4 is served by a single stack, while Boiler No. 5 is served by two stacks.

Boiler No. 4 is permitted for a maximum PM emission rate of 0.3 pound per million British thermal units (lb/MMBtu), while Boiler No. 5 is permitted for a maximum PM emission rate of 0.2 lb/MMBtu. Each boiler is also permitted for a maximum NO_x emission rate of 0.45 lb/MMBtu and a maximum VOC emission rate of 1.5 lb/MMBtu.

Both Boilers No. 4 and 5 are permitted to burn No. 6 fuel oil with a maximum sulfur content of 1.0 percent. Each boiler is limited to 82.5 MMBtu or 543 gallons per hour (gal/hr) of No. 6 fuel oil, based on fuel oil burner design.

The Osceola Farms Mill is currently operated under Title V operating permit No. 0990019-003-AV, issued January 26, 2001.

Palm Beach Power Corporation recently received a draft PSD permit to restart the Osceola cogeneration facility located adjacent to the Osceola Farms Mill. However, it has been decided that the Palm Beach Power facility will not restart. The facility is currently up for sale. Therefore, to provide assurance for the continued future operation of the Osceola Farms Mill, Boiler Nos. 4 and 5 at the Mill are being modified. These modifications and changes will allow the Osceola Farms Mill to continue to operate in the most efficient manner and to process the sugarcane in the shortest time period.

2.2 BOILER NOS. 4 AND 5 MODIFICATIONS

2.2.1 BOILER DESIGN INFORMATION

The existing cell- type Boiler Nos. 4 and 5 will be converted to inclined grate type boilers, utilizing water-cooled, pinhole design. Boiler Nos. 2 and 3 at Osceola Farms already have water-cooled, pinhole grates, and the operations of these units have proved to be very satisfactory. In addition to the new type grates, the steam drum, main generating bank steam tubes, and the superheater tubes will be replaced on each boiler. New bagasse feeders with overfire air will be installed.

The water-cooled, pinhole grate design represents modern spreader-stoker technology for boilers in applications where plugging of the pinholes is not a problem (i.e., not a significant amount of sand particles in the fuel). This design incorporates a water circulation system within the grate to keep the grate from overheating. The benefit of this design is that the underfire air amount as well as temperature can be varied (controlled) to result in more complete combustion. Since the bagasse fuel contains a significant amount of moisture, higher temperature underfire air is beneficial to drying the moisture from the fuel, allowing more complete combustion and carbon burnout. The underfire air to the boilers will be preheated to approximately 400°F. The underfire air will comprise about 90 percent of the total air supplied to the boiler.

The new overfire air system, in conjunction with the new bagasse feeders, will result in more complete mixing of the fuel and the combustion air, resulting in more complete combustion. Hot spots and cold spots in the furnace, which can cause higher emissions, will be reduced. The bagasse feeders will also utilize hot air to aid in distributing the bagasse within the furnace. About 10 percent of the total air to the boiler will be from the overfire air system. The overfire air and the bagasse feeders air will be preheated to the same temperature, approximately 400°F.

Currently, ash removal from the cell-type Boiler Nos. 4 and 5 is a manual operation, performed about once every 8 hours. As part of the proposed modifications, steam nozzles will be installed adjacent to the grate on each boiler to facilitate ash removal from the grate. The grates will be "inclined", allowing the steam nozzles to "move" the ash to one end of the boiler for collection. The boilers will continue to be opened to clean out ash from the ash pit inside the boiler, approximately once per 8 hours. This operation is expected to require approximately 30 minutes to perform. During this operation, some cold air intrusion into the boiler may occur.

It is currently planned that the conversions will be performed during two consecutive off-seasons. During the summer of 2005, the pressure parts of the boilers (steam drum, tubes, etc.) will be replaced. During the summer of 2006, the inclined water-cooled pinhole grates and associated equipment will be installed. These changes will allow the boilers to operate at a higher steam pressure and temperature condition of 350 psig and 575°F, compared to the current conditions of 280 psig and 550°F. These new conditions match those steam operating conditions for Boiler Nos. 2 and 3 and will, therefore, allow the Mill to operate more efficiently overall.

The boilers will each be permitted to produce 170,000 lb/hr steam as a 3-hr average and 160,000 lb/hr steam as a daily 24-hr average. Each boiler will be permitted to operate while combusting carbonaceous (bagasse) fuel alone at a maximum 1-hr heat input rate of 336.6 million British thermal units per hour (MMBtu/hr); a maximum 24-hr heat input rate of 316.8 MMBtu/hr; and a crop season average heat input of 297.0 MMBtu/hr. These heat input rates correspond to steam rates of 170,000 lb/hr 1-hr average; 160,000 lb/hr 24-hr average; and 150,000 lb/hr crop season average. The design steam conditions will be 350 psig and 575°F.

Boiler Nos. 4 and 5 will fire bagasse as their primary fuel, with No. 6 fuel oil used for startup, shutdown, malfunction, and as a supplementary fuel. The maximum sulfur content of the No. 6 fuel oil burned will be 1.0 percent.

The maximum heat input rates and fuel usage rates for Boiler Nos. 4 and 5 after the modification are shown in Table 2-1. Refer to Appendix A for boiler design data and calculations. The maximum heat input rates are calculated assuming a thermal efficiency of 55 percent. This thermal efficiency has traditionally been used for bagasse boilers in the Florida sugar industry.

Boiler Nos. 4 and 5 will be permitted to operate up to 160 days per year (3,840 hr/yr) during the period October 1 through April 30 (i.e., during the crop season only). The maximum annual steam production rate and heat input rate for each boiler, based on a crop season average steam production rate of 150,000 lb/hr, will be 576 million lb steam/yr and 1,140,480 million British thermal units per year (MMBtu/yr), respectively. In addition, the total combined annual heat input rate for both boilers will be limited to 2,000,000 MMBtu/yr, equivalent to 1,010,101,010 lb steam/yr.

Any additional steam generated by the modified boilers will be used to process sugarcane and to generate additional electricity for internal consumption.

Boiler Nos. 4 and 5 will continue to use the existing No. 6 fuel oil burners to fire oil as a backup or supplementary fuel. The fuel oil burned in Boiler Nos. 4 and 5 will consist of No. 6 fuel oil with a maximum sulfur content of 1.0 percent. The maximum heat input of No. 6 fuel oil will continue to be 82.5 MMBtu/hr. Fossil fuel burning will be limited on an annual basis to 800,000 gal/yr for the two boilers combined. This is equivalent to 121,600 MMBtu/yr at 152,000 British thermal units per gallon (Btu/gal) for No. 6 fuel oil.

A process flow diagram for Boiler Nos. 4 and 5 is presented in the permit application form. Due to the installation of the new equipment and control devices on Boiler Nos. 4 and 5, a shakedown period of 45 days after the start of the crop season (2006-2007 season) is requested. Compliance testing would be performed after the shakedown period.

Specific design information, drawings, etc., for the Boiler Nos. 4 and 5 modifications are not presently available, since the project is still in the planning stages. However, Osceola experience with Boiler Nos. 2 and 3 will ensure that the modifications are appropriately designed and installed. Osceola is considering several reputable contractors for the project, including Alpha, Bigelow, and McBurney. Upon request from FDEP, Osceola Farms will provide engineering drawings and other design data for the modifications as they become available, prior to actual construction on the boilers.

2.2.2 AIR POLLUTION CONTROL EQUIPMENT

The air pollution control equipment for Boiler Nos. 4 and 5 currently consists of two scrubbers operating in parallel on each boiler. The scrubbers are of the wet impingement type (Joy Turbulaire Type D-48 for Boiler No. 4, and Type D-40 for Boiler No. 5). Boiler No. 4 is served by a single stack, while Boiler No. 5 is served by two stacks.

Boiler Nos. 4 and 5 will continue to use the existing wet scrubbers for PM control after the proposed modification. Currently, these scrubbers must achieve a 0.3-lb/MMBtu PM limit for Boiler No. 4, and a 0.2-lb/MMBtu PM limit for Boiler No. 5. Historically, actual PM emissions from Boiler No. 4 have ranged from 0.140 to 0.255 lb/MMBtu (compliance test averages). Actual PM emissions from Boiler No. 5 have ranged from 0.075 to 0.180 lb/MMBtu (refer to Appendix D).

The scrubbers will be modified by installing mist eliminators in each scrubber, and along with the improvements in combustion efficiency, will be capable of achieving a PM limit of 0.15 lb/MMBtu after the proposed modification. This limit represents the most stringent PM emission limit in the Florida sugar industry for an existing bagasse boiler utilizing a wet scrubber, and has been determined to represent BACT for such boilers. Osceola Farms will install the mist eliminators in the upper section of each existing scrubber. Each mist eliminator will be equipped with a water flush system, which will operate frequently (e.g., every 3 minutes) to clean the mist eliminator to avoid plugging. The pressure drop across the mist eliminator will also be monitored.

Boiler No. 6 already utilizes a mist eliminator in its wet scrubber, and has proved to operate very satisfactorily. PM emissions during compliance testing of the Boiler No. 6 over the last 7 years has resulted in emissions of no greater than 0.15 lb/MMBtu.

GCPs will be implemented for Boiler Nos. 4 and 5 for control of NO_x, CO, and VOC emissions. The proposed GCPs for Boiler Nos. 4 and 5 are presented in Appendix C.

2.3 PROPOSED BOILER NOS. 4 AND 5 EMISSIONS

2.3.1 MAXIMUM SHORT-TERM EMISSIONS

The estimated maximum 3-hr average emissions for Boiler Nos. 4 and 5 each, operating at the maximum 1-hr steam production rate of 170,000 lb/hr, are shown in Table 2-2. The maximum 24-hr emissions, based on 160,000 lb/hr steam (24-hr average), are shown in Table 2-3. The basis for the maximum emissions is shown in the footnotes to the table and are discussed below.

Maximum PM emissions for carbonaceous fuel burning are based on an emission limit of 0.15 lb/MMBtu. PM_{10} emissions for carbonaceous fuel burning are 93 percent of total PM emissions, or 0.14 lb/MMBtu, based on an EPA stack test study.

SO_2 emissions due to carbonaceous fuel burning (0.06 lb/MMBtu) are based on test data from similar bagasse-fired boilers with wet scrubber control.

Maximum short-term NO_x emissions due to carbonaceous fuel burning (0.25 lb/MMBtu) are based on the proposed BACT emission limit for this pollutant. The limit is based on limited test data from Boiler Nos. 4 and 5, as well as test data from Boiler No. 2, which is similar in design to the proposed converted Boiler Nos. 4 and 5 (i.e., inclined grate and utilizes a water-cooled, pinhole grate). Refer to Appendix D for historic test data. The proposed limit is also equivalent to BACT limits for similar existing bagasse-fired boilers in the Florida sugar industry, and recognize there may be short-term variations in NO_x levels.

Maximum CO and VOC emissions due to carbonaceous fuel burning are estimated at 6.0 and 0.4 lb/MMBtu, respectively. The VOC emissions are based on the proposed BACT emission limit for this pollutant. The limits are based on limited test data from Boiler Nos. 4 and 5, as well as test data from Boiler Nos. 2 and 3, which are similar in design to the proposed converted Boiler Nos. 4 and 5. Refer to Appendix D for test data. The proposed VOC limit is also equivalent to BACT limits for similar existing bagasse-fired boilers in the Florida sugar industry.

Mercury (Hg) emissions due to carbonaceous fuel firing are based on a stack test study undertaken at Osceola Farms during the 1992-1993 crop season. The emission factor for fluorides (Fl) and lead (Pb) for carbonaceous fuel firing are based on stack test data from New Hope Power Partnership when burning 100-percent bagasse (see Appendix D). The maximum stack test average from the most recent two tests for any boiler at New Hope Power was used.

Emissions of sulfuric acid mist (SAM) for carbonaceous fuel-firing are based on an EPA AP-42 factor for fuel oil firing that indicates approximately 5 percent of sulfur dioxide (SO_2) is emitted as sulfur trioxide (SO_3). The SO_3 is then converted to SAM emissions by multiplying by the ratio of SO_3 and sulfuric acid (H_2SO_4) molecular weights (98/80).

The proposed PM emission limit for fuel oil firing is the State of Florida limitation of 0.1 lb/MMBtu. PM_{10} emissions for fuel oil firing are based on 100 percent of PM emissions. Emission factors for all other pollutants for No. 6 fuel oil firing are based on AP-42 factors.

During periods of ash removal from the boiler (described in Section 2.2.1), some cold air intrusion may occur, which in turn could result in short-term increases in PM, CO and VOC emissions, while decreasing NO_x emissions. Such emissions are not readily quantifiable; however, PM will be the least affected due to the wet scrubber control system, which will continue to provide high PM removal efficiencies during these periods.

2.3.2 MAXIMUM ANNUAL EMISSIONS

Maximum annual emissions for Boiler Nos. 4 and 5 individually are presented in Table 2-4, while annual emissions from the two boilers combined are presented in Table 2-5. The individual annual emissions are shown to reflect the proposed annual fuel oil usage cap for the two boilers combined (800,000 gal/yr). Thus, each boiler individually could burn up to 800,000 gal/yr of No. 6 fuel oil (Table 2-4), but the combined fuel oil usage in the two boilers will not exceed 800,000 gal/yr (Table 2-5).

Emission factors for estimating maximum emissions are the same as utilized for the short-term emission rates (see Table 2-2), except in the case of NO_x. Annual average NO_x emissions are expected to be no greater than 0.22 lb/MMBtu. This factor is based on historic NO_x test data from Boiler No. 2, which is similar in design to the converted Boiler Nos. 4 and 5.

The maximum annual heat input rate to Boiler No. 4 or No. 5 is based on an average steam rate of 150,000 lb/hr for 160 days per year, equivalent to 1,140,480 MMBtu/yr. In addition, the total annual steam production rate for Boiler Nos. 4 and 5 combined will not exceed 1,010,101,010 lbs steam, equivalent to 2,000,000 MMBtu/yr total for both boilers.

2.3.3 HAZARDOUS AIR POLLUTANTS

Osceola Farms does not have any test data indicating significant hazardous air pollutants (HAPs) emissions from its sugar Mill boilers, and therefore quantification of HAPs emissions is not possible at this time. Recent sugar industry test data indicates that there are HAPs emissions from sugar industry bagasse-fired boilers. Although, these emissions may not be representative of Osceola Farms' HAPs emissions, it is likely that the Osceola Farms Mill is a major source of HAPs emissions.

2.3.4 VISIBLE EMISSIONS

Visible emissions from Boiler Nos. 4 and 5 will be limited to the current permit limit of 30-percent opacity (6-minute average), with up to 40-percent opacity allowed for two 6-minute periods per hour.

2.3.5 COMPLIANCE DEMONSTRATION

To demonstrate compliance with the proposed emission limits for PM/PM_{10}, three 1-hr EPA Method 5 runs are proposed. For NO_x, CO, and VOC, however, due to the variability in emissions resulting from the bagasse fuel, a longer time period for compliance testing should be allowed. It is requested that compliance testing for up to a 24-hr period be allowed for Boiler Nos. 4 and 5 for these pollutants. This will reduce the effects of higher short-term emissions in demonstrating compliance with the proposed emission limits. During such longer term tests, periods of boiler ash removal should be excluded as excess emissions.

2.4 BAGASSE CONVEYING AND HANDLING SYSTEM

The bagasse conveying and handling system will not be affected by the proposed project. The total amount of bagasse fed to the boilers will continue to be controlled by the amount of sugarcane processed by the sugar mill. The amount of sugarcane processed by the sugar mill will be dependent on the size of the sugarcane crop. The proposed boiler project may allow increased Mill production and bagasse production to increase on a short-term basis. However, the annual bagasse production or bagasse usage will continue to be controlled by the sugarcane crop.

2.5 SITE LAYOUT AND STRUCTURES

A plot plan of the Osceola Farms Sugar Mill, showing stack locations and buildings, is presented in Attachment OF-FI-C2 of the application form. The dimensions of the major buildings and structures are presented in Section 6.0.

2.6 STACK PARAMETERS

Stack parameters for Boiler Nos. 4 and 5, both existing and after the proposed modification, are presented in Table 2-6.

Table 2-1. Maximum Fuel Usage and Heat Input Rates for Boiler Nos. 4 and 5, Osceola Farms Co.

Fuel	Heat Input	Heat Transfer Efficiency (%)	Fuel Firing Rate (per boiler)	
	Maximum Short-Term (per boiler)			
	(MMBtu/hr)			
Bagasse (3-hour max)[a]	336.6	55	93,500	lb/hr
Bagasse (24-hour max)[b]	316.8	55	88,000	lb/hr
No. 6 Fuel Oil	82.5	55	542.8	gal/hr
	Annual Average (per boiler)			
	(MMBtu/yr)			
NORMAL OPERATIONS (100% BAGASSE)				
Bagasse[c]	1,140,480	55	158,400	TPY
No. 6 Fuel Oil	0	55	0	gal/yr
TOTAL	1,140,480			
MAXIMUM OIL FIRING				
Biomass	1,018,880	55	141,511	TPY
No. 6 Fuel Oil	121,600	55	800,000	gal/yr
TOTAL	1,140,480			

[a] Based on 170,000 lb/hr steam and 1,089 Btu/lb net enthalpy.

[b] Based on 160,000 lb/hr steam and 1,089 Btu/lb net enthalpy.

[c] Equivalent to 150,000 lb/hr steam @3,840 hr/yr, based on 1,089 Btu/lb net enthalpy.

Notes:

Fuels may be burned in combination, not to exceed total heat input.

Based on fuel heating values as follows:

Bagasse - 3,600 Btu/lb

No. 6 Fuel Oil - 152,000 Btu/gal

Table 2-2. Maximum 3-Hour Emissions for Boiler Nos. 4 and 5 (per boiler), Osceola Farms Company

	No. 6 Fuel Oil				Bagasse				Maximum No. 6 Fuel Oil	
Regulated Pollutant	Emission Factor (lb/1000 gal)	Ref.	Activity Factor (gal/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	w/Remainder Due to Bagasse (lb/hr)	Maximum Any Fuel (lb/hr)
Particulate (PM)	15.2	(1)	542.8	8.25	0.15	(6)	336.6	50.49	46.37	50.49
Particulate (PM_{10})	15.2	(2)	542.8	8.25	0.14	(7)	336.6	47.12	43.82	47.12
Sulfur Dioxide	157	(3)	542.8	85.22	0.06	(6)	336.6	20.20	100.47	100.47
Nitrogen Oxides	55	(4)	542.8	29.85	0.25	(6)	336.6	84.15	93.38	93.38
Carbon Monoxide	5	(4)	542.8	2.71	6.0	(6)	336.6	2,019.60	1,527.31	2,019.60
VOC	0.28	(4)	542.8	0.15	0.4	(6)	336.6	134.64	101.79	134.64
Mercury	1.13E-04	(10)	542.8	6.13E-05	7.95E-06	(8)	336.6	0.0027	0.0021	2.68E-03
Fluorides	3.73E-02	(10)	542.8	2.02E-02	4.18E-04	(9)	336.6	0.141	0.106	1.41E-01
Lead	1.51E-03	(10)	542.8	8.20E-04	2.44E-05	(9)	336.6	0.0082	0.0070	8.21E-03
Sulfuric Acid Mist --3-hr Average	9.62	(5)	542.8	5.22	0.0037	(5)	336.6	1.24	6.15	6.15

References:
1. Equivalent to limit of 0.1 lb/MMBtu, assuming 152,000 Btu/gal for No. 6 fuel oil.
2. PM_{10} assumed as 100% of PM.
3. Based on AP-42 Section 1.3 (USEPA 9/98) formula 157(S) lb/1000 gal, where S = 1.0%.
4. Based on AP-42 Section 1.3 (USEPA 9/98).
5. Based on emission factor for SO_2, assuming a 5% conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).
6. Proposed permit limits. VOC reported as methane.
7. PM_{10} based on 93% of PM, based on one stack test (EPA).
8. Based on Osceola mercury emission testing program for 1992-1993 crop season.
9. Based on average emissions from New Hope Power Partnership most recent two stack tests when burning bagasse only.
10. From AP-42 Table 1.3-11 (USEPA 9/98).

Table 2-3. Maximum 24-Hour Emissions for Boiler Nos. 4 and 5 (per boiler), Osceola Farms Company

	No. 6 Fuel Oil				Bagasse				Maximum No. 6 Fuel Oil w/Remainder Due to Bagasse	Maximum Any Fuel
Regulated Pollutant	Emission Factor (lb/1000 gal)	Ref.	Activity Factor (gal/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	(lb/hr)	(lb/hr)
Particulate (PM)	15.2	(1)	542.8	8.25	0.15	(6)	316.8	47.52	43.40	47.52
Particulate (PM_{10})	15.2	(2)	542.8	8.25	0.14	(7)	316.8	44.35	41.05	44.35
Sulfur Dioxide	157	(3)	542.8	85.22	0.06	(6)	316.8	19.01	99.28	99.28
Nitrogen Oxides	55	(4)	542.8	29.85	0.22	(6)	316.8	69.70	81.40	81.40
Carbon Monoxide	5	(4)	542.8	2.71	3.7	(6)	316.8	1,172.16	869.62	1,172.16
VOC	0.28	(4)	542.8	0.15	0.4	(6)	316.8	126.72	93.87	126.72
Mercury	1.13E-04	(10)	542.8	6.13E-05	7.95E-06	(8)	316.8	0.0025	0.0019	2.52E-03
Fluorides	3.73E-02	(10)	542.8	2.02E-02	4.18E-04	(9)	316.8	0.132	0.098	1.32E-01
Lead	1.51E-03	(10)	542.8	8.20E-04	2.44E-05	(9)	316.8	0.0077	0.0065	7.73E-03
Sulfuric Acid Mist	9.62	(5)	542.8	5.22	0.0037	(5)	316.8	1.16	6.08	6.08

References:

1. Equivalent to limit of 0.1 lb/MMBtu, assuming 152,000 Btu/gal for No. 6 fuel oil.
2. PM_{10} assumed as 100% of PM.
3. Based on AP-42 Section 1.3 (USEPA 9/98) formula 157(S) lb/1000 gal, where S = 1.0%.
4. Based on AP-42 Section 1.3 (USEPA 9/98).
5. Based on emission factor for SO_2, assuming a 5% conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).
6. Proposed permit limits. VOC reported as methane.
7. PM_{10} based on 93% of PM, based on one stack test (EPA).
8. Based on Osceola mercury emission testing program for 1992-1993 crop season.
9. Based on average emissions from New Hope Power Partnership most recent two stack tests when burning bagasse only.
10. From AP-42 Table 1.3-11 (USEPA 9/98).

Table 2-4. Future Maximum Annual Emissions for Boiler Nos. 4 and 5 (each), Osceola Farms Company

	No. 6 Fuel Oil				Bagasse				Maximum No. 6 Fuel Oil w/Remainder Due to Bagasse	Maximum Annual Emissions
Pollutant	Fuel Usage[a] (gal/yr)	Emission Factor (lb/1,000 gal)	Ref.	Boiler Emissions (TPY)	Heat Input[b] (MMBtu/yr)	Emission Factor (lb/MMBtu)	Ref.	Boiler Emissions (TPY)	(TPY)	(TPY)
PM	800,000	15.2	(1)	6.08	1,140,480	0.15	(6)	85.54	82.50	85.54
PM_{10}	800,000	15.2	(2)	6.08	1,140,480	0.14	(7)	79.55	77.15	79.55
SO_2	800,000	157	(3)	62.80	1,140,480	0.06	(6)	34.21	93.37	93.37
NO_x	800,000	55	(4)	22.00	1,140,480	0.22	(6)	125.45	134.08	134.08
CO	800,000	5	(4)	2.00	1,140,480	3.70	(6)	2,109.89	1,886.93	2,109.89
VOC[c]	800,000	0.28	(4)	0.112	1,140,480	0.40	(6)	228.10	203.89	228.10
Hg	800,000	1.13E-04	(10)	4.52E-05	1,140,480	7.95E-06	(8)	0.0045	0.0041	0.0045
F	800,000	3.73E-02	(10)	1.49E-02	1,140,480	4.18E-04	(9)	0.239	0.23	0.239
Pb	800,000	1.51E-03	(10)	6.04E-04	1,140,480	2.44E-05	(9)	0.014	0.013	0.014
SAM	800,000	9.62	(5)	3.847	1,140,480	3.68.E-03	(5)	2.10	5.72	5.72

[a] Total fuel oil usage for Boiler Nos. 4 and 5, equivalent to 121,600 MMBtu/yr @ 152,000 Btu/gal. All oil could potentially be burned in one boiler.

[b] Based on 150,000 lb/hr (average) and net enthalpy of 1,089 Btu/lb; 55% efficiency; equivalent to 297.0 MMBtu/hr; 3,840 hr/yr.

[c] Emissions due to bagasse firing reported as methane.

References:

1. Equivalent to limit of 0.1 lb/MMBtu, assuming 152,000 Btu/gal for No. 6 fuel oil.
2. PM_{10} assumed as 100% of PM.
3. Based on AP-42 Section 1.3 (USEPA 9/98) formula 157(S) lb/1000 gal, where S = 1.0%.
4. Based on AP-42 Section 1.3 (USEPA 9/98).
5. Based on emission factor for SO_2, assuming a 5% conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).
6. Proposed permit limits. VOC reported as methane.
7. PM_{10} based on 93% of PM, based on one stack test (EPA).
8. Based on Osceola mercury emission testing program for 1992-1993 crop season.
9. Based on average emissions from New Hope Power Partnership most recent two stack tests when burning bagasse only.
10. From AP-42 Table 1.3-11 (USEPA 9/98).

Table 2-5. Future Maximum Annual Emissions for Boiler Nos. 4 and 5 (combined), Osceola Farms Company

	No. 6 Fuel Oil				Bagasse				Maximum	Maximum
Pollutant	Fuel Usage[a] (gal/yr)	Emission Factor (lb/1,000 gal)	Ref.	Boiler Emissions (TPY)	Heat Input[b] (MMBtu/yr)	Emission Factor (lb/MMBtu)	Ref.	Boiler Emissions (TPY)	No. 6 Fuel Oil w/Remainder Due to Bagasse (TPY)	Annual Emissions (TPY)
PM	800,000	15.2	(1)	6.08	2,000,000	0.15	(6)	150.00	146.96	150.00
PM_{10}	800,000	15.2	(2)	6.08	2,000,000	0.14	(7)	139.50	137.10	139.50
SO_2	800,000	157	(3)	62.80	2,000,000	0.06	(6)	60.00	119.15	119.15
NO_x	800,000	55	(4)	22.00	2,000,000	0.22	(6)	220.00	228.62	228.62
CO	800,000	5	(4)	2.00	2,000,000	3.70	(6)	3,700.00	3,477.04	3,700.00
VOC[c]	800,000	0.28	(4)	0.112	2,000,000	0.40	(6)	400.00	375.79	400.00
Hg	800,000	1.13E-04	(10)	4.52E-05	2,000,000	7.95E-06	(8)	0.0080	0.0075	0.0080
F	800,000	3.73E-02	(10)	1.49E-02	2,000,000	4.18E-04	(9)	0.418	0.41	0.418
Pb	800,000	1.51E-03	(10)	6.04E-04	2,000,000	2.44E-05	(9)	0.024	0.024	0.024
SAM	800,000	9.62	(5)	3.847	2,000,000	3.68.E-03	(5)	3.68	7.30	7.30

[a] Total fuel oil usage for Boiler Nos. 4 and 5, equivalent to 121,600 MMBtu/yr @ 152,000 Btu/gal.

[b] Based on two boilers generating a combined total of 1,010,101,010 lbs steam per year at a net enthalpy of 1,089 Btu/lb; 55% efficiency; equivalent to 2,000,000 MMBtu/yr.

[c] Emissions due to bagasse firing reported as methane.

References:

1. Equivalent to limit of 0.1 lb/MMBtu, assuming 152,000 Btu/gal for No. 6 fuel oil.
2. PM_{10} assumed as 100% of PM.
3. Based on AP-42 Section 1.3 (USEPA 9/98) formula 157(S) lb/1000 gal, where S = 1.0%.
4. Based on AP-42 Section 1.3 (USEPA 9/98).
5. Based on emission factor for SO_2, assuming a 5% conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).
6. Proposed permit limits. VOC reported as methane.
7. PM_{10} based on 93% of PM, based on one stack test (EPA).
8. Based on Osceola mercury emission testing program for 1992-1993 crop season.
9. Based on average emissions from New Hope Power Partnership most recent two stack tests when burning bagasse only.
10. From AP-42 Table 1.3-11 (USEPA 9/98).

Table 2-6. Stack Parameters for Boiler Nos. 4 and 5, Osceola Farms Company- Existing and Future Operations

Unit	Fuel	Operation	Averaging Time	HIR (MMBtu/hr)	Stack Height (ft)	Diameter (ft)	Flow Rate (acfm)	Velocity (ft/s)	Temperature (oF)
Boiler No. 4	Bagasse	Existing	--	240.8	90.0	6.0	96,342	56.8	153.5
		Future	3-hour	336.6	90.0	6.0	134,650	79.4	153.5
		Future	24-hour	316.8	90.0	6.0	126,730	74.7	153.5
		Future	Annual	297.0	90.0	6.0	118,809	70.0	153.5
Boiler No. 5 East Stack	Bagasse	Existing	--	281.2	90.0	5.0	63,904	54.2	153.7
		Future	3-hour	336.6	90.0	5.0	76,501	64.9	153.7
		Future	24-hour	316.8	90.0	5.0	72,001	61.1	153.7
		Future	Annual	297.0	90.0	5.0	67,501	57.3	153.7
Boiler No. 5 West Stack	Bagasse	Existing	--	286.9	90.0	5.0	56,258	47.7	153.1
		Future	3-hour	336.6	90.0	5.0	76,501	64.9	153.1
		Future	24-hour	316.8	90.0	5.0	72,001	61.1	153.1
		Future	Annual	297.0	90.0	5.0	67,501	57.3	153.1

Note: acfm = actual cubic feet per minute
°F = degrees Fahrenheit
ft = feet
ft/s = feet per second

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

Federal and state air regulatory requirements for a new source of air pollution are discussed in Sections 3.1 to 3.4. The applicability of these regulations to the proposed modifications to Boiler Nos. 4 and 5 at Osceola Farms 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 NAAQS were promulgated to protect the public health, and secondary NAAQS 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 NAAQS 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 NAAQS, except in the case of SO_2. For SO_2, Florida has adopted the former 24-hr secondary standard of 260 micrograms per cubic meter ($\mu g/m^{3}$), and former annual average secondary standard of 60 $\mu g/m^3$.

3.2 PREVENTION OF SIGNIFICANT DETERIORATION (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 tons per year (TPY) or more or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under the CAA. "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.

EPA has promulgated limitations to increases above an air quality baseline concentration level of SO_2, PM_{10}, and NO_2 concentrations that would constitute significant deterioration. The EPA class designations 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 CAA. Congress promulgated areas as Class I (international parks, national wilderness areas, 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 new facilities and major modifications are required to undergo the following analyses 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 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 or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques (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 issued 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 requires 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 judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and PSD Workshop Manual was used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program, including the adoption of a new "top-down" approach to BACT decision making.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limits that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified.

EPA has issued a draft guidance document on the top-down approach entitled *Top-Down Best Available Control Technology Guidance Document* (EPA, 1990). This document has not yet been issued as final guidance or as rule. EPA has also published the document entitled *OAQPS Cost Control Manual* (EPA, 1996) to assist industry and regulators in estimating capital and annual costs of pollution control equipment.

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, 2003).

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 with AAQS and PSD increments.

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

SO_2	3-hr	1 μg/m^3
	24-hr	0.2 μg/m^3
	Annual	0.1 μg/m^3
PM_{10}	24-hr	0.3 μg/m^3
	Annual	0.2 μg/m^3
NO_2	Annual	0.1 μg/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 the 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 Class II increments. For PSD Class I analysis and regional haze impact analysis, a 3-year period is now required. The meteorological data are selected based 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 selection of the weather data is normally discussed with and approved by the regulatory agency reviewing the air permit application prior to initiating air modeling.

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_{10} 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_{10} 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_{10}, 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; and
3. The trigger date, which is August 7, 1977, for SO_2 and PM_{10}, 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, 1987).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that FDEP 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 general type of information required for the Osceola Farms project is presented in Section 2.0.

The 1977 CAA Amendments provide 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 FDEP 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 kilometer (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 PSD 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); Rule 62-212.400]. 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).

3.2.7 PSD APPLICABILITY FOR BOILER NOS. 4 AND 5

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(TSP), and NO_2. The nearest Class I area to the site is the Everglades National Park (ENP), located about 120 km (75 miles) south of the Osceola Farms Mill site.

Pollutant Applicability

The existing Osceola Farms Mill is considered to be a "major existing facility" because the annual emissions of several regulated pollutants from the Mill are greater than 250 TPY. Therefore, PSD review is required for any modification that results in a net increase in emissions greater than the PSD significant emission rates.

The PSD applicability for the proposed modification is presented in Table 3-3. Baseline emissions for Boiler Nos. 4 and 5 are shown, based on calculations presented in Appendix B. The current annual emissions are based on the last 2 years (2001-2002) of actual operation (heat input due to bagasse and fuel oil). Refer to the footnotes in Appendix B for the basis of the emission factors for Boiler Nos. 4 and 5. Also shown in Table 3-3 are the future potential emissions from Boiler Nos. 4 and 5, from Table 2-5.

As shown in Table 3-3, the potential increase in emissions due to the proposed modification exceeds the PSD significant emission rates for NO_x and VOC. As a result, PSD review applies for these pollutants.

Source Impact Analysis

A source impact analysis was performed for NO_2 emissions resulting from the proposed modification. As shown in Section 6.0, the predicted increase in impacts of NO_2 due to the proposed modification is predicted to be above the significant impact level for NO_2. As a result, a modeling analysis incorporating the impacts from other sources is required for NO_2. The appropriate analyses are presented in Section 6.0.

Ambient Monitoring

Based on the increase in emissions from the proposed modification (see Table 3-3), a pre-construction ambient monitoring analysis is required for NO_2 and VOC, and monitoring data are 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 NO_2 are not required to be submitted for this project because, as shown in Table 3-4, the proposed modification's impacts are predicted to be below the applicable *de minimis* monitoring concentration for these pollutants (see Table 3-2). A pre-construction ambient monitoring analysis is required for VOC. This analysis is presented in Section 4.0.

GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65-meters (m) [213 feet (ft)] high. The Boiler Nos. 4 and 5 existing stacks are 90-ft high, and will not be modified as part of the project. These stack heights do not exceed the *de minimis* GEP stack height. However, as discussed in Section 6.0, Air Quality Impact Analysis, since the stack height is less than GEP, building downwash effects must be considered in the modeling analysis. As a result, the potential for downwash of the Boiler Nos. 4 and 5 emissions caused by nearby structures is included in the modeling analysis.

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions, all major new facilities and major 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.

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.

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." The NSPS are codified in 40 CFR Part 60.

For Boiler Nos. 4 and 5, the NSPS Subpart Db for Industrial/Commercial/Institutional Boilers is potentially applicable. Subpart Db is applicable to certain industrial boilers with a heat input capacity of 100 MMBtu/hr or greater, which were constructed, modified, or reconstructed after June 19, 1984.

The NSPS for Industrial Boilers, 40 CFR 60, Subpart Db, will not be applicable to Boiler Nos. 4 and 5. The boilers are existing boilers, not currently subject to Subpart Db. The fuel oil firing system on the boilers is designed for less than 100 MMBtu/hr, and these systems will not be modified by the proposed project. Subpart Db does not regulate the burning of bagasse fuel.

In addition, the boilers will not be "reconstructed" as defined in the NSPS. In the General Provisions for the NSPS Rules, 40 CFR 60, Subpart A, *reconstruction* is defined as follows:

> "***Reconstruction***" means the replacement of components of an affected facility to such an extent that:
>
> (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and
>
> (2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

In the General Provisions for the MACT Rules, 40 CFR 63, Subpart A, *reconstruction* is defined as follows:

> ***Reconstruction***, unless otherwise defined in a relevant standard, means the replacement of components of an affected or previously nonaffected source to such an extent that:
>
> (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source; and
>
> (2) It is technologically and economically feasible for the reconstructed source to meet the relevant standard(s) established by the Administrator pursuant to Section 112 of the Act. Upon reconstruction, an affected source, or a stationary source that becomes an affected source, is subject to relevant standards for new sources, including compliance dates, irrespective of any change in emission of hazardous air pollutants from that source.

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

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

Osceola Farms has developed a budget for the proposed project based on several vendor quotes. The projected cost of the modifications is the same for each boiler. For the grate replacement, including structural steel and refractory, the estimated cost is $600,000 per boiler. For the steam drum and steam tube replacements, the estimated cost, including structural steel and refractory, is $900,000 per boiler. Thus, the total installed capital cost of the modifications is $1,500,000 per boiler. A more detailed cost breakout is provided below.

Cost Item	Estimated Cost
Drum and Tube Replacement per Boiler	
Three (3) Drums And Set Of Tubes	$335,284
One (1) Set Of Superheater Tubes	$32,920
Accessories (Estimate)	$75,000
Refractory Contract (Estimate)	$100,000
Structural Contractor (Estimate)	$50,000
Osceola Labor	$100,000
Osceola Fringes	$100,300
Sub-Total	$793,504
Contingency - 10 %	$79,350
Total	**$872,854**
Grate Replacement Per Boiler	
Supplier	**TOTAL**
Grate Pieces (Estimate)	$65,000
Headers And Tubes (Estimate)	$65,000
Accessories (Estimate)	$30,000
Refractory Contract (Estimate)	$150,000
Structural Contractor (Estimate)	$150,000
Osceola Labor	$50,000
Osceola Fringes	$29,500
Sub-Total	$460,000
Contingency - 10 %	$46,000
Total	**$585,500**
Total All Activities Per Boiler =	**$1,458,354**

The term "comparable entirely new facility" would consist of a new boiler with components identical to the repaired boiler. Reconstruction calculations do not include air pollution control equipment. Using previously developed costs for new bagasse boilers in the Florida sugar industry, the cost of a new boiler, comparable to Boiler Nos. 4 and 5 (i.e., 160,000 lb/hr steam), would be on the order of $6,000,000, excluding air pollution control equipment. Therefore, the planned modifications represent only about 25 percent of the cost of a new boiler. As a result, reconstruction is not triggered under the NSPS definitions.

3.4.2 MACT RULES

Maximum achievable control technology (MACT) regulations for industrial boilers with a heat input capacity of 10 MMBtu/hr or greater were proposed by EPA on January 13, 2003, and a final rule was signed in February 2004. However, the final rule has not yet been published in the Federal Register. These regulations will apply to all boilers located at major sources of HAP emissions. When these regulations are finalized, and if the Osceola Farms Mill is definitively determined to be a major source of HAPs emissions, Boiler Nos. 4 and 5 will be subject to the existing source MACT regulations.

Osceola Farms has analyzed the final boiler MACT rule, and believes it will be able to comply with the alternative metals standard in lieu of meeting the PM limit for existing boilers. The alternative metals standard limits the sum of eight metals to no more than 0.001 lb/MMBtu. Similarly, Osceola Farms believes it will be able to comply with the mercury limit of 9 lb/trillion Btu and the HCl limit of 0.09 lb/MMBtu. These limits can be met because of the low levels of these substances in bagasse. Compliance with these emission limits can be achieved either through fuel analysis or stack testing.

The final MACT rule does not limit CO emissions, or any other pollutants, from existing boilers.

3.4.3 FLORIDA RULES

FDEP regulations for existing carbonaceous fuel burning equipment are contained in Rule 62-296.410. These rules require that carbonaceous fuel burning equipment meet a PM emission limit of 0.2 lb/MMBtu. Opacity is limited to 30 percent (6-minute average), with up to 40 percent allowed for up to 2 minutes per hour.

The applicable emission limit for PM for Boiler Nos. 4 and 5 is 0.2 lb/MMBtu of heat input (Rule 62-296.410). The proposed PM emission rate of 0.15 lb/MMBtu for Boiler Nos. 4 and 5 will comply with the specified limit.

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

Pollutant	Averaging Time	AAQS			PSD Increments		Significant Impact Levels[d]
		National Primary Standard	National Secondary Standard	State of Florida	Class I	Class II	
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, the EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour standard of 65 µg/m³ (3-year average of 98th percentile) and an annual standard of 15 µg/m³ (3-year average at community monitors). Implementation of these standards has not yet occurred. 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. The 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 µg/m³ is equal to or less than 1. For modeling purposes, compliance is based on the sixth highest 24-hour average value over a 5-year period.

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

[d] Maximum concentrations.

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

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

Pollutant	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	NA
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
Beryllium	NESHAP	0.0004	0.001, 24-hour
Asbestos	NESHAP	0.007	NM
Vinyl Chloride	NESHAP	1	15, 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.

NA = Not applicable.
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.

Sources: 40 CFR 52.21.
Rule 62-212.400.

Table 3-3. PSD Source Applicability Analysis, Osceola Farms Boiler Nos. 4 and 5 Modification

Regulated Pollutant	Current Actual Emissions From Osceola Farms[a] Boiler No. 4 (TPY)	Boiler No. 5 (TPY)	Total (TPY)	Future Potential Emissions Boiler No. 4 and 5 Combined (TPY)	Net Change In Emissions Due to Proposed Project (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Triggered?
Particulate (TSP)	77.45	57.42	134.86	150.00	15.14	25	No
Particulate (PM_{10})	72.04	53.41	125.45	139.50	14.05	15	No
Sulfur Dioxide	40.89	42.99	83.89	119.15	35.27	40	No
Nitrogen Oxides	79.66	78.50	158.16	228.62	70.46	40	Yes
Carbon Monoxide	1,874.52	1,736.08	3,610.59	3,700.00	89.41	100	No
VOC	92.52	63.29	155.81	400.00	244.19	40	Yes
Mercury	0.0032	0.0032	0.0064	0.008	0.0016	0.1	No
Fluorides	0.17	0.17	0.34	0.42	0.07	3	No
Lead	0.010	0.010	0.020	0.024	0.005	0.6	No
Sulfuric Acid Mist	2.50	2.63	5.14	7.30	2.16	7	No

[a] Actual emissions based on the average emissions for 2002 and 2003.

TSP = Total Suspended Particles
PM_{10} = Particulate Matter with aerodynamic diameter less than or equal to 10 microns
VOC = Volatile Organic Compounds

Table 3-4. Increase in Impacts Due to Proposed Project Compared to Class II Significant Impact Levels and Ambient Monitoring *De Minimis* Levels

Pollutant	Averaging Time	Maximum Concentration[a] (ug/m^3)	EPA Class II Significant Impact Levels (ug/m^3)	*De Minimis* Monitoring Concentration (ug/m^3)	Ambient Monitoring Review Applies?
Nitrogen Dioxide	Annual[b]	1.8	1	14	No

[a] Highest concentration from significant impact analysis (see Section 6.0).

[b] Maximum annual concentrations predicted based on October to April operation.

Note: NA = Not Applicable, No standard exists.

4.0 AMBIENT MONITORING ANALYSIS

4.1 MONITORING REQUIREMETS

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 would potentially emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rates (see Table 3-2).

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* (1987).

An exemption from the preconstruction ambient monitoring requirements is also available if certain criteria are met. If the predicted increase in ambient concentrations, due to the proposed modification, is less than specified *de minimis* concentrations, then the modification can be exempted from the pre-construction air monitoring requirements for that pollutant. As described in Section 3.2.7.4, the proposed project will result in ambient concentrations less than *de minimis* concentrations for NO_2. However, existing ambient NO_2 data are presented to provide background concentrations for the NO_2 modeling analysis.

There is no PSD *de minimis* monitoring concentration established for VOC. However, an increase in VOC emissions of 100 TPY or more requires a preconstruction ambient monitoring analysis for ozone (O_3). This analysis is presented in Section 4.3.

4.2 NO_2 AMBIENT BACKGROUND CONCENTRATIONS

A summary of existing continuous ambient NO_2 data for the monitor located nearest to the Osceola Farms site is presented in Table 4-1. Data are presented for the last 4 years of record, 2000 through 2003. As shown, the nearest NO_2 monitoring station was located in West Palm Beach.

The monitor shows that ambient NO_2 concentrations were well below the ambient air quality standard of 100 $\mu g/m^3$, annual average. The highest annual average concentration recorded during any year was 32 $\mu g/m^3$. This value was used for purposes of the ambient NO_2 background concentration for use in the modeling analysis. The monitor in West Palm Beach is considered to provide a very conservative estimate of background NO_2 concentrations for the Osceola Farms site, due to the significant mobile traffic and point sources impacting the West Palm Beach monitor compared to the rural nature of the Osceola Farms site.

4.3 OZONE AMBIENT MONITORING ANALYSIS

Ambient ozone (O_3) monitoring data from existing monitoring stations operated by FDEP are included in this application to satisfy the preconstruction monitoring requirements for VOC (see Table 4-2). Palm Beach County and adjacent counties are classified as attainment or maintenance areas for O_3. The nearest monitors to Osceola Farms that measure O_3 concentrations are located at Royal Palm Beach and Delray Beach in Palm Beach County.

The O_3 monitor at Royal Palm Beach was moved in 2000 to another location but remained near the original site in Royal Palm Beach. Since O_3 is a regional pollutant, O_3 monitoring data collected in Palm Beach County are considered to be representative of O_3 concentrations for the region and are used to satisfy this requirement. These stations are operated by the FDEP and measure concentrations according to EPA procedures.

From 2000 through 2003, the second-highest 1-hr average O_3 concentration measured at Royal Palm Beach (the nearest site to the project) was 0.090 parts per million (ppm). This maximum concentration is less than the existing 1-hr average O_3 AAQS of 0.12 ppm. In addition, the 3-year average of the 4th highest 8-hr average O_3 concentrations was 0.067 ppm, which is below the revised 8-hr average O_3 AAQS of 0.08 ppm. These O_3 monitoring data are proposed as part of this construction permit application to satisfy the preconstruction monitoring requirement for the project.

Table 4-1. Summary of Continuous Ambient Nitrogen Dioxide Data Collected Near the Osceola Farms Site

City	Site ID No.	Location	Year	Number of Observations	Percent of Data Recovery	Annual Average Concentration ppm	Annual Average Concentration µg/m³
Palm Beach	12-099-1004	3700 Belvedere Road	2003	8,480	97	0.0144	27
			2002	5,988	68	0.0169	32
			2001	8,373	96	0.017	32
			2000	8,553	98	0.016	30

Note: µg/m³ = micrograms per cubic meter
ppm = parts per million
Source: FDEP, Quick Look Reports, 2000-2003
(based on EPA's Air Quality Subsystem)

Table 4-2. Summary of Maximum Ambient Ozone Concentrations Measured Near Osceola Farms

				Concentration (ppm)		
				1-Hour		8-Hour
County	AIRS No.	Location	Year	Highest	2nd Highest	3-year Average 4th Highest
Florida AAQS [a]				**NA**	**0.12**	**0.08**
Palm Beach	12-099-0009	Royal Palm Beach	2003	0.081	0.078	0.067
		980 Crestwood Blvd. North	2002	0.082	0.075	0.067
		(Waste Water Plant)	2001	0.107	0.090	NA
			2000	0.083	0.078	NA
Palm Beach	12-099-2004	Delray Beach	2003	0.087	0.081	0.066
		210 NW 1st Ave.	2002	0.091	0.084	0.068
			2001	0.102	0.098	0.075
			2000	0.096	0.093	0.078
			1999	0.108	0.104	0.076

Note: NA = not applicable.
AAQS = ambient air quality standard.

Source: FDEP, Quick Look Report, 2000-2003 (based on EPA's Air Quality Subsystem).

[a] On July 18, 1997, EPA promulgated revised AAQS for O_3. The O_3 standard was modified to be 0.08 ppm for the 8-hour average; achieved when the 3-year average of 99th percentile values is 0.08 ppm or less. Until recently, the courts had stayed these standards but they will now be implemented by the states in the next several years. FDEP has not yet adopted the revised standards.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 REQUIREMENTS

The 1977 CAA Amendments established requirements for the approval of pre-construction permit applications under the PSD program. As discussed in Section 3.2.2, one of these requirements is that BACT be installed for applicable pollutants. BACT determinations must be made on a case-by-case basis considering technical, economic, energy, and environmental impacts for various BACT alternatives. To bring consistency to the BACT process, the EPA developed the "top-down" approach to BACT determinations.

The first step in a top-down BACT analysis is to determine, for each applicable pollutant, the most stringent control alternative available for a similar source or source category. If it can be shown that this level of control is not feasible on the basis of technical, economic, energy, or environmental impacts for the source in question, then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration.

In the case of the proposed project, NO_x and VOC emissions from Boiler Nos. 4 and 5 require a BACT analysis. Since the two boilers will be designed identically after the proposed modification, the control technology review is the same for both boilers. The BACT analysis is presented in the following sections.

5.2 NITROGEN OXIDES

5.2.1 PROPOSED CONTROL TECHNOLOGY

Boiler Nos. 4 and 5 will be primarily bagasse-fired, and the boilers will be converted from cell type boilers to grate type boilers, with inclined grates. In this type boiler, the bagasse is introduced into the furnace above the grate. The boilers will utilize an over-fire air system and new bagasse feeders with air injection to promote vigorous mixing of the combustion gases and the fuel. Lighter bagasse particles burn in suspension. Fuel not combusting in suspension falls onto the grate and continues to burn to complete the combustion process. However, the boiler is designed to primarily combust the bagasse in suspension. This system promotes burning in suspension to improve combustion efficiency and reduce emissions.

The boilers will also utilize water-cooled, pinhole grate design. The water-cooled grate has significant advantages over conventional grate design. Underfire combustion air can be introduced at a higher temperature, thereby reducing the amount of underfire air and allowing a greater percentage of overfire air. Thus, the grate design allows staging of the combustion process, which reduces potential NO_x emissions.

The proposed BACT for NO_x is the use of good combustion practices; water-cooled, pinhole grate design; preheated underfire and overfire air; new bagasse feeders; and low nitrogen-content fuels (bagasse and 1.0% sulfur No. 6 fuel oil). The proposed BACT emission limit for NO_x is 0.25 lb/MMBtu for bagasse firing, as a short-term limit. This limit is based on test data from Boiler No. 2 at the Mill, which is also an inclined grate boiler using a water-cooled, pinhole grate, and Boiler Nos. 4 and 5 will be very similar to this boiler after they are modified. Maximum annual NO_x emissions from the converted boilers are expected to be 0.22 lb/MMBtu or less.

5.2.2 BACT ANALYSIS

Previous BACT Determinations

As part of the BACT analysis, a review was performed of previous BACT determinations for similar biomass-fired industrial boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's web page. From this information, BACT determinations issued within the last 10 years (i.e., since 1993) were identified. A summary of these BACT determinations is presented in Table 5-1.

All previous BACT determinations for NO_x emissions at similar facilities have ranged from 0.14 to 0.46 lb/MMBtu. The lowest determination of 0.14 lb/MMBtu was issued for U.S. Sugar Corporation Boiler No. 8. However, this was for a new bagasse-fired boiler. The latest determinations for existing boilers undergoing PSD review are for Fort James Operating Company, S.D. Warren Company, and U.S. Sugar Corporation boiler No. 4. These modifications to existing boilers received BACT determinations in the range of 0.20 to 0.25 lb/MMBtu. One of these (S.D. Warren) was based on the use of selective non-catalytic reduction (SNCR) with urea injection, while the other two were based on GCPs. In fact, the S.D. Warren determination is the only BACT determination based on SNCR.

Control Technology Feasibility

The technically feasible NO_x controls for Boiler Nos. 4 and 5 are shown in Table 5-2. As shown in the table, there are five primary types of NO_x abatement methods, with various techniques within each method. Each available technique was listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency. It is also indicated if Boiler Nos. 4 and 5 will employ the specific technique.

Potential Control Method Descriptions

Removal of Nitrogen

Ultra-Low Nitrogen Fuel -- The fuels combusted in the boilers will be primarily bagasse. Combustion of this fuel results in inherently low emissions of NO_x, and lower than conventional fuels, due to the characteristically low levels of nitrogen and high level of moisture associated with bagasse fuel. Osceola will control NO_x emissions from the boilers through the use of low nitrogen content fuels.

Oxidation of NO_x with Subsequent Absorption

Inject Oxidant -- The oxidation of nitrogen to its higher valence states makes NO_x soluble in water. When this is done a gas absorber can be effective. Oxidants that have been injected into the gas stream are ozone, ionized oxygen, or hydrogen peroxide. This NO_x reduction technique has not been demonstrated on large-scale boilers or with biomass combustion, and as such is not considered a demonstrated control technology for the Boilers.

Non-Thermal Plasma Reactor (NTPR) -- This technique generates electron energies in the gas stream that generate gas-phased radicals, such as hydroxyl (OH) and atomic oxygen (O) through collision of electrons with water and oxygen molecules present in the flue gas stream. In the flue gas stream, these radicals oxidize NO_x to form nitric acid (HNO_3), which can then be condensed out through a wet condensing precipitator. NTPR has not been demonstrated on large-scale boilers or with biomass combustion, and as such is not considered a demonstrated control technology for the Boilers.

Chemical Reduction of NO_x

Selective Catalytic Reduction (SCR) -- SCR uses a catalyst to react injected ammonia to chemically reduce NO_x. The catalyst has a finite life in flue gas and some ammonia slips through without being reacted. SCR has historically used precious metal catalysts, but can now also use base metal and zeolite catalyst materials. Technical difficulties associated with applying SCR include no operating experience on bagasse, and likely premature catalyst deactivation due to chemical poisoning of the catalyst resulting from the alkali content of the ash. Results of analysis of the ash from two bagasse samples from the Osceola Farms Mill are shown in Table 5-3. The analysis shows that the ash contains 0.5 percent sodium, 3.5 to 7.5 percent potassium, 1.4 to 2.2 percent phosphorus, and over 2.5 percent chlorides (all as oxides, dry basis). Based on discussions with SCR catalyst vendors, the high levels of these compounds would lead to rapid catalyst deactivation, and SCR would not be feasible unless the SCR system is placed after a highly effective PM control device, such as an ESP.

The high moisture content of bagasse (approximately 50 percent moisture) is also a concern for catalyst operation. If the SCR placement was prior to the air preheater, where the flue gas temperature is in the range of 600 to 1,000°F, high particulate and moisture loading would be a concern. This would lead to catalyst fouling, reduced NO_x removal efficiency, and failure of the system. If the SCR were placed after the existing wet scrubber, the particulate and moisture loading would still be too high for the SCR. SCR could be placed after a more efficient dry particulate control device [such as an electrostatic precipitator (ESP)], but would require that the inlet gas stream be reheated to the range of 600 to 1,000°F, the operating temperature range of SCR catalyst.

Selective Non-Catalytic Reduction (SNCR) -- In SNCR, ammonia or urea is injected within the boiler or in ducts in a region where temperature is between 1,600 and 2,000°F. This technology is based on temperature ionizing the ammonia or urea instead of using a catalyst or non-thermal plasma. The temperature window for SNCR is very important because outside of it either more ammonia slips through the system or more NO_x is generated than is being chemically reduced. SNCR has been demonstrated as a feasible technology for biomass combustion and can achieve NO_x reductions up to 50 percent.

SNCR is currently in operation on three wood/bagasse-fired boilers at New Hope Power Partnership in Palm Beach County, and has been successfully demonstrated. The NO_x limit issued for a recent modification of these boilers was 0.15 lb/MMBtu. SNCR is also being installed on a new bagasse-fired boiler (Boiler No. 8) at U.S. Sugar Corporation in Clewiston, Florida, with a NO_x limit of 0.14 lb/MMBtu.

However, SNCR has not been demonstrated in practice on an existing, older, 100-percent bagasse-fired boiler operating in a harsh environment. The required temperature window is limited in the existing boilers due to the high moisture fuel and furnace configuration. The residence time for urea to react is also limited due to the narrow temperature window and the higher gas velocities compared to more modern boilers with a larger furnace volume. The heat release rate for the modified Boiler Nos. 4 and 5 will be approximately 49,000 British thermal units per hour per cubic foot (Btu/hr-ft^3). By comparison, modern bagasse boilers such as U.S. Sugar's Boiler No. 8 have a heat release rate of less than 21,000 Btu/hr-ft^3. Also of concern is the ability to control the temperature window within the boiler due to changing bagasse fuel quality. Higher CO concentrations in a bagasse boiler may also limit the NO_x reduction efficiency. It is noted that for a similar bagasse-fired boiler modification at Atlantic Sugar Association (Boiler No. 5, permit No. PSD-FL-078B, issued 6/07/2001), SNCR was determined to be technically infeasible due to these concerns.

These operating limitations and inherent technical problems would affect the achievable NOx removal efficiency, if SNCR was installed on Boiler Nos. 4 and 5. Typically, SNCR systems can achieve up to 50-percent reduction in NO_x emissions. For Boiler Nos. 4 and 5, a much lower efficiency, possibly as low as 25 percent, might be attained.

There are also serious concerns related to ammonia slip and unreacted urea impinging on the boiler tubes and causing premature boiler tube failure and other effects on downstream equipment (air heater, superheater, etc.), and associated maintenance/repair costs. This is especially true in a retrofit situation such as Boiler Nos. 4 and 5, where the SNCR system cannot be designed optimally due to the existing boiler configuration.

SCONO$_x$ – This technology is a proven, proprietary, and patented catalytic oxidation and absorption technology, which is recognized by the EPA as "demonstrated in practice" for the control of NO_x emissions from combined cycle gas turbines. These gas turbines burn natural gas or distillate fuel oil. This technology has never been designed for, or demonstrated on, a biomass-fired boiler.

Ecotube – This technology uses in-furnace retractable injection lances to inject air and/or ammonia/urea directly into the combustion zone to improve combustion and better stage the combustion process, and to promote the SNCR process. This system is operating in Europe. The Ecotube vendor cites a number of benefits, including increased efficiency, lower corrosion, reduced fly ash, lower NO_x (60- to 90-percent reduction), reduced and more stable CO, and lower costs than other comparable SNCR systems.

Reducing Residence Time at Peak Temperature

Air Staging of Combustion -- Combustion air is divided into two streams. The first stream is mixed with fuel in a ratio that produces a reducing flame. The second stream is injected downstream of the flame and creates an oxygen-rich zone. Boiler Nos. 4 and 5 will utilize over-fire air, which acts as air staging of combustion.

Fuel Staging of Combustion -- This is staging of combustion using fuel instead of air. Fuel is divided into two streams. The first stream feeds primary combustion that operates in a reducing fuel-to-air ratio. The second stream is injected downstream of primary combustion, causing the net fuel to air ratio to be slightly oxidizing. Excess fuel in the primary combustion zone dilutes heat to reduce temperature. The second stream oxidizes the fuel while reducing the NO_x to N_2.

Inject Steam -- Injection of steam causes the stoichiometry of the mixture to be changed and dilutes calories generated by combustion. These actions cause combustion temperature to be lower, and in-turn reduces the amount of thermal NO_x formed.

Each of these techniques to reduce residence time at peak temperature is technically feasible.

Reducing Peak Temperature

Flue Gas Recirculation (FGR) -- Recirculation of cooled flue gas reduces combustion temperature by diluting the oxygen content of the combustion air and by causing heat to be diluted in a greater mass of flue gas. Heat in the flue gas can be recovered by a heat exchanger. This reduction of temperature lowers the thermal NO_x concentration that is generated. FGR is not known to have ever been utilized on a bagasse-fired boiler.

Reburn -- In a boiler outfitted with reburn technology, a set of natural gas burners are installed above the primary combustion zone. Natural gas is injected to form a fuel-rich, oxygen-deficient combustion zone above the main firing zone. Nitrogen oxides, created by the combustion process in the main portion of the boiler, drift upward into the reburn zone and are converted to molecular nitrogen. The technology requires no catalysts, chemical reagents, or changes to any existing burners. Typical reburn systems also incorporate redesign of the combustion air system along with the water-cooled, pinhole grate to provide less excess air (LEA). Natural gas reburn is not a feasible technology for the Boiler Nos. 4 and 5 since natural gas is not available at the Osceola Farms Mill.

Over-Fire Air (OFA) -- When primary combustion uses a fuel-rich mixture, use of OFA completes the combustion. Because the mixture is always off-stoichiometric when combustion is occurring, the temperature is reduced. After all other stages of combustion, the remainder of the fuel is oxidized in the OFA. The modified Boiler Nos. 4 and 5 will utilize an improved OFA system along with the water-cooled pinhole grate to promote vigorous mixing of the combustion gases to maximize combustion efficiency and reduce NO_x emissions.

Less Excess Air (LEA) -- Excess airflow combustion has been correlated to the amount of NO_x generated. Limiting the net excess airflow can limit NO_x content of the flue gas. The modified boilers will utilize a combustion system that minimizes the amount of excess air in the furnace.

Combustion Optimization -- Combustion optimization refers to the active control of combustion. The active combustion control measures seek to find optimum combustion efficiency and to control combustion at that efficiency. The modified Boiler Nos. 4 and 5 will be optimized for maximum combustion efficiency, considering the constraints on the existing systems.

Low NO_x Burners (LNB) -- A LNB provides a stable flame that has several different zones. For example, the first zone can be primary combustion. The second zone can be Fuel Reburning (FR) with fuel added to chemically reduce NO_x. The third zone can be the final combustion in low excess air to limit the temperature. LNB is not an option for biomass fired system with pneumatic distributor for fuel feed system. In this system, the fuel is dropped into the discharge chute to the pneumatic distributor and is injected into the furnace above the grate. Lighter particles burn in suspension. Fuel not combusting in suspension, falls to the grate to complete the process.

Low-NO_x burners can be employed for fuel oil firing. However, these type burners will not be utilized on the Boiler Nos. 4 and 5 because fuel oil firing will be limited to less than a 10-percent annual capacity factor.

Economic Analysis

SCR

The top ranked feasible control technology, as shown in Table 5-2, is SCR. The cost analysis for tail end SCR is presented in Table 5-4. As described previously, to accommodate SCR, the existing wet scrubber system would need to be replaced with an ESP. Therefore, the cost estimates also reflect the costs of an ESP, as presented in Table 5-5.

The total estimated capital cost of SCR for each boiler is estimated at $4.39 million. The total annualized cost of applying tail-end SCR with an ESP is estimated at $1,200,000 per year. This annual cost includes energy requirements (No. 2 fuel oil) for flue gas reheat. In addition, a fuel oil storage tank and associated loading station, and piping to reheat unit would be required. The costs of this equipment are included in the estimated cost of the SCR system.

Uncontrolled baseline NO_x emissions are based on the future maximum NO_x emissions from Boiler Nos. 4 and 5. The potential future NO_x emissions with SCR are based on 90-percent removal efficiency with the SCR system. Therefore, the reduction in NO_x emissions due to SCR is 102.9 TPY per boiler. The resulting cost effectiveness of adding tail end SCR is estimated at over $11,900 per ton of NO_x removed. This high cost is considered to be economically infeasible for the project.

SNCR

Another top ranked feasible control technology is SNCR, as shown in Table 5-2. The cost analysis for SNCR is presented in Table 5-6. The total estimated capital cost of SNCR for both boilers combined is estimated at $5.1 million. The total annualized cost of applying SNCR is estimated at $935,000 per year.

Uncontrolled baseline NO_x emissions are based on the future maximum NO_x emissions of 228.6 TPY from Boiler Nos. 4 and 5. The potential future NO_x emissions with SNCR are based on 25-percent removal efficiency with the SNCR system. Therefore, the reduction in NO_x emissions due to SNCR is 57.2 TPY per boiler. The resulting cost effectiveness of adding SNCR is estimated at over $16,000 per ton of NO_x removed. Even if a more typical NO_x reduction efficiency of 50-percent is assumed for this application, the cost effectiveness would still be greater than $8,000 per ton of NO_x removed. This high cost is considered to be economically infeasible for the project.

Ecotube

The Ecotube vendor will not provide a specific quote for the Osceola Farms boilers unless an engineering study is performed for a cost of $45,000. The vendor would only provide a range of $0.5 million to $2.0 million. In addition, without the engineering study, the vendor will not provide an efficiency guarantee. However, these costs and the probable performance of the system appear to be similar to SNCR. Therefore, considering the high costs and high degree of uncertainty for the system, the Ecotube was not considered further.

Environmental Impacts

As shown in Tables 6-8 and 6-9, the maximum predicted annual NO_2 impacts for the proposed project are above the EPA significant impact levels. However, the maximum pollutant concentrations due to the proposed Boiler Nos. 4 and 5 modification's emissions demonstrate compliance with AAQS and PSD increments. The results of the modeling analysis demonstrate the proposed project will not have an adverse affect on air quality and will comply with all applicable AAQS and PSD increments. Additional NO_x controls would result in an insignificant reduction of ambient impacts.

It is also important to consider that Boiler Nos. 4 and 5 will not operate during the summer ozone producing months. The boilers will be permitted to operate only during the months of October through April. Therefore, the boilers' NO_x emissions will not contribute to maximum ozone levels, which occur during the summer months.

Energy Impacts

Energy penalties occur with SCR. SCR will require inputs of energy, water, and ammonia. The major energy requirement of tail-end SCR is the reheating of the gas stream to the catalyst activation temperature, 700°F. The cost of reheating the gas stream will be approximately $500,800 per year per boiler and will require a significant amount of No. 2 fuel oil (estimated at 859,000 gallons per year), as well as generate additional air pollutants.

5.2.3 BACT SELECTION

For Osceola Boiler Nos. 4 and 5, the combination of good combustion practices; water-cooled, pinhole grate design; over-fire air; low excess air; and low nitrogen-content fuel (bagasse) can achieve the maximum amount of emissions reduction that is technically and economically feasible, and is demonstrated in practice. Additional controls should be rejected as BACT for the Boiler Nos. 4 and 5 for the following reasons:

- Boiler Nos. 4 and 5 will not operate during the summer ozone producing months, and therefore the boilers' NO_x emissions will not contribute to maximum ozone levels, which occur during the summer months.
- Tail-end SCR, with the required ESP control device, has a capital and annual operating cost of $4.39 million and $1,346,000, respectively, resulting in a cost effectiveness of at least $12,600 per ton of NO_x removed, but likely higher based on actual expected NO_x emissions.
- SNCR has not been demonstrated in practice on an older, existing, 100-percent bagasse-fired boiler and operating in a harsh environment. Serious concerns are related to achieving the proper temperature window and residence time for reaction of the urea, effect of higher CO concentrations, as well as ammonia slip and unreacted urea impinging on the boiler tubes and causing premature boiler tube failure and other effects on downstream equipment (air heater, superheater, etc.), and associated maintenance/repair costs. This is a retrofit situation, where the SNCR system cannot be designed optimally due to boiler configuration, the limited residence time for urea to react, changing temperatures in the boiler, etc. In addition, SNCR is considered economically infeasible for Boiler Nos. 4 and 5, with cost effectiveness ranging from $8,000 to $16,000 per ton of NO_x removed.
- The maximum average NO_x emissions expected from the modified Boiler Nos. 4 and 5 are lower than the proposed annual emission rate of 0.22 lb/MMBtu.

Therefore, the proposed NO_x BACT limit for Boiler Nos. 4 and 5 is based on good combustion practices, over-fire air, and low nitrogen content fuel (bagasse), with a maximum average emission rate of 0.22 lb/MMBtu for bagasse firing.

5.3 VOLATILE ORGANIC COMPOUNDS (VOCS)

5.3.1 PROPOSED CONTROL TECHNOLOGY

VOC emissions are proposed to be controlled through proper furnace design and good combustion practices, including control of combustion air and temperature and distribution of fuel on the grate, as well as control over furnace loads and transient conditions. The proposed VOC BACT emission limit for each boiler is 0.4 lb/MMBtu, for bagasse firing.

5.3.2 BACT ANALYSIS

Previous BACT Determinations

As part of the BACT analysis, a review was performed of previous VOC BACT determinations for industrial boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's web page. A summary of the BACT determinations for biomass-fired industrial boilers from this review is presented in Table 5-7.

The VOC emission limits for biomass-fired industrial boilers range from 0.007 to 2.62 lb/MMBtu. This rather large range of emissions is due to differences in boiler design and operation, as well as differences in fuel. From the review of previous determinations, it is evident that VOC BACT determinations for biomass-fired industrial boilers have typically been based on GCPs and boiler design. Boilers similar in design and operation to Osceola Farms Boiler Nos. 4 and 5 include U.S. Sugar Corp. Clewiston Boiler No. 4 and Atlantic Sugar Association Boiler No. 5. These boilers received VOC BACT limits of 0.50 and 0.25 lb/MMBtu, respectively.

Control Technology Feasibility

The technically feasible add-on VOC controls for Boiler Nos. 4 and 5 are shown in Table 5-8. As shown, there are four types of add-on VOC abatement methods. Each available technique was listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency.

Potential Control Method Descriptions

Refrigerated Condensers

The most common types of condensers used are surface and contact condensers. In surface condensers, the coolant does not contact the gas stream. Most surface condensers in refrigerated systems are shell and tube type. Shell and tube condensers circulate the coolant through tubes. The VOC condenses on the outside surface of the tube. Plate and frame type heat exchangers are also used as condensers in refrigerated systems. In these condensers, the coolant and the vapor flow separately over thin plates. In either design, the condensed VOC vapors drain away to a collection tank for storage, reuse, or disposal.

Contact condensers cool the vapor stream by spraying either a liquid at ambient temperature or a chilled liquid directly into the gas stream.

Refrigerated condensers are used as air pollution control devises for treating emissions with high VOC concentrations [>5,000 parts per million by volume (ppmv)], in applications involving gasoline bulk terminals, storage, etc. Refrigerated condensers are not technically feasible for reduction of VOC from industrial boilers, and as such are not technically feasible for the Osceola boilers.

Carbon Absorbers

Adsorption is employed to remove VOC compounds from low to medium concentration gas streams. Adsorption is a phenomenon where gas molecules passing through a bed of solid particles are selectively held there by attractive forces, which are weaker and less specific than those of chemical bonds. During adsorption, a gas molecule migrates from the gas stream to the surface of the solid where it is held by physical attraction releasing energy, the heat of adsorption, which typically equals or exceeds the heat of condensation. Adsorption capacity of the solid for the gas tends to increase with the gas phase concentration, molecular weight, diffusivity, polarity, and boiling point. Gases form actual chemical bonds with the adsorbent surface groups. There are five types of adsorption techniques (see Table 5-8).

Of the five techniques, fixed bed units are typically utilized for controlling continuous VOC containing streams from flow rates ranging from several hundred to several thousand cubic feet per minute. Based on the gas flow rate of Boiler Nos. 4 and 5, carbon adsorption is not technically feasible for this project.

Flare

Flaring is a VOC control process in which the VOCs are piped to a remote, usually elevated, location and burned in an open flame in the open air using a specially designed burner tip and auxiliary fuel. Flares are not technically feasible for Boiler Nos. 4 and 5 due to the large gas volume and low Btu value of the gas stream.

Incinerators

The two basic types of incinerators are thermal and catalytic. Thermal systems may be direct flame incinerators with no energy recovery, flame incinerators with a recuperative heat exchanger, or regenerative systems, which operate in a cyclic mode to achieve high-energy recovery. Catalytic systems include fixed bed (packed bed or monolith) systems and fluid-bed systems, both of which provide for energy recovery. Catalytic systems are not an option for biomass combustion due to catalyst poisoning.

Although thermal incinerators are theoretically feasible for Boiler Nos. 4 and 5, because of the high flue gas volume and low concentration of VOCs it is estimated that the total incinerator natural gas usage would be approximately 17,000 standard cubic feet per hour (scf/hr), equal to 73.4 MMscf/yr. The combustion of natural gas would result in increased NO_x emissions. Natural gas is not currently available at the Osceola Farms Mill. For these reasons incineration is considered not technically feasible for Boiler Nos. 4 and 5.

5.3.3 BACT SELECTION

The proposed VOC emission limits for Boiler Nos. 4 and 5 are 0.4 lb/MMBtu for bagasse firing. Boiler Nos. 4 and No. 5 will minimize VOC emissions through proper furnace design and good combustion practices, including: control of combustion air and combustion temperature; controlled distribution of fuel on the combustion gate; and better controls over the furnace loads and transient conditions. This level of control is consistent with previous determinations. Good combustion practices proposed for Boiler Nos. 4 and 5 are presented in Appendix C.

Table 5-1. BACT Determinations for NO_x Emissions From Biomass-Fired Industrial Boilers

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	Removal Efficiency %
Fort James Operating Company, Inc.--Old Town	ME	A-180-71-AI-A[d]	7/28/2004	265.2 MMBtu/hr	0.25 lb/MMBtu	0.25	Low NO_x burners, overfire air, FGR	--
US Sugar Corp.--Clewiston Blr No. 8	FL	PSD-FL-333[b]	11/21/2003	1,030 MMBtu/hr	0.14 lb/MMBtu	0.14	Urea-based SNCR, low NO_x burners, overfire air, and low nitrogen fuels	99
New Hope Power Partnership	FL	FL-0069[c]	Draft	760 MMBtu/hr	0.15 lb/MMBtu	0.15	SNCR, Good Combustion Practices	--
New Hope Power Partnership	FL	FL-0069	1/31/2002	715 MMBtu/hr	0.15 lb/MMBtu	0.15	SNCR, Clean fuels	
Martinsville Thermal, LLC--Thermal Ventures	VA	VA-0268	2/15/2002	120 MMBtu/hr	0.4 lb/MMBtu	0.4	Good Combustion Practices	--
S.D. Warren Co.--Blr No. 2	ME	ME-0021	11/27/2001	1,300 MMBtu/hr	0.2 lb/MMBtu	0.2	SNCR	--
US Sugar Corp.--Clewiston Blr No. 4	FL	PSD-FL-272A[c]	5/18/2001	633 MMBtu/hr	0.20 lb/MMBtu	0.20	Good Combustion Practices	--
International Paper Company-Riegelwood Mill	NC	NC-0092	5/10/2001	600 MMBtu/hr	0.35 lb/MMBtu	0.35	Good Combustion Practices	--
Atlantic Sugar Association--Blr No. 5	FL	PSD-FL-078B[c]	6/7/2001	255.3 MMBtu/hr	0.16 lb/MMBtu	0.16	Good Combustion Practices	--
GULF STATES PAPER CORP	AL	AL-0122	10/14/1998	98 MMBtu/hr	0.3 lb/MMBtu	0.3		--
Archer Daniels Midland Co.--Northern	ND	ND-0018	7/9/1998	200 MMBtu/hr	0.20 lb/MMBtu	0.20		--
POTLATCH CORPORATION	MN	MN-0033	6/24/1998	140 MMBtu/hr	0.3 lb/MMBtu	0.3	Water vapor inj. & staged combustion	--
WELLBORN CABINET INC	AL	AL-0107	2/3/1998	29.5 MMBtu/hr	13.57 lb/hr	0.46	Boiler design & comb. Control: oxygen trim, staged comb., steam injection, & overfire air.	31
GULF STATES PAPER CORPORATION	AL	AL-0116	12/10/1997	775 MMBtu/hr	0.3 lb/MMBtu	0.3	Low NO_x natural gas & fuel oil burner	50
Champion International	AL	AL-0112	12/9/1997	710 MMBtu/hr	0.25 lb/MMBtu	0.25	Addition of tertiary air system	30
PLUM CREEK MFG - EVERGREEN FACILITY	MT	MT-0007	2/15/1997	225 MMBtu/hr	104 lb/hr	0.46		--
MEAD CONTAINERBOARD	AL	AL-0099	1/15/1997	620 MMBtu/hr	0.25 lb/MMBtu	0.25	Combustion Control	
Vaughan Furniture Company	VA	VA-0237	8/28/1996	28 MMBtu/hr	24 TPY[b]	0.20	No controls feasible	--
Willamette Industries - Marlboro Mill	SC	SC-0045	4/17/1996	470 MMBtu/hr	0.3 lb/MMBtu	0.3	Good combustion control	--
GEORGIA PACIFIC CORP. - GLOSTEE FACILIT	MS	MS-0023	4/11/1995	244 MMBtu/hr	0.3 lb/MMBtu	0.3		
U.S. SUGAR CORP--Clewiston Blr No. 7	FL	FL-0094	1/31/1995	738 MMBtu/hr	0.25 lb/MMBtu	0.25	LOW NO_X BURNERS	--
Scott Paper Company	WA	WA-0276	12/21/1994	718 MMBtu/hr	150 ppm @ 7% O_2 30/day avg	--	Combustion controls	--
KES CHATEAUGAY PROJECT	NY	NY-0055	12/19/1994	275 MMBtu/hr	0.23 lb/MMBtu	0.23	NO CONTROLS	--
WEYERHAEUSER CO.	AL	AL-0079	10/28/1994	91 MMBtu/hr	0.23 lb/MMBtu	0.23		--

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2004.

[a] To convert from lb/hr, the emission limit was divided by the throughput rate. To convert from lb/day, assumed 24 hr/day operation.

[b] Assuming 8,760 hr/yr.

[c] This information obtained from actual PSD permit, not Clearinghouse.

[d] From the draft BACT determination.

Table 5-2. NO_x Control Technolgy Feasibility Analysis for Boiler Nos. 4 and 5

NO_x Abatement Method	Technique Now Available	Estimated Efficiency	Technically Feasible? (Y/N)	Demonstrated? (Y/N)	Rank Based on Control Efficiency	Employed by Boiler Nos.4 and 5? (Y/N)
1. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data	Y	Y	4	Y
2. Oxidation of NO_x with subsequent absorption.	Inject Oxidant	60 - 80%	N	N	NA	N
	Non-Thermal Plasma Reactor (NTPR)	60 - 80%	N	N	NA	N
3. Chemical reduction of NO_x	Selective Catalytic Reduction (SCR)	35 - 80%	Y	N	1	N
	Selective Non-Catalytic Reduction (SNCR)	35 - 80%	Y	Y	1	N
	$SCONO_X$™	35 - 80%	N	N	NA	N
	Ecotube	50 - 90%	Y	N	1	N
4. Reducing residence time at peak temperature	Air Staging of Combustion	50 - 65%	Y	Y	2	Y
	Fuel Staging of Combustion	50 - 65%	Y	Y	2	N
	Inject Steam	50 - 65%	Y	Y	2	N
5. Reducing peak temperature	Flue Gas Recirculation (FGR)	15 -25%	Y	Y	3	N
	Natural Gas Reburning (NGR)	15 -25%	N	N	NA	N
	Over Fire Air (OFA)	15 -25%	Y	Y	3	Y
	Less Excess Air (LEA)	15 -25%	Y	Y	3	Y
	Combustion Optimization	15 -25%	Y	Y	3	Y
	Reduce Air Preheat	15 -25%	Y	Y	3	N
	Low NO_x Burners (LNB)	15 -25%	N	N	NA	N

Note: NA = Not Applicable

Table 5-3. Osceola Farms Mill Bagasse Ash Analysis Compared to Coal Ash

Constituent	Osceola Farms Bagasse Samples[a]	Coal Fly Ash				
		Class "F"	Class "C"	hvBb Utah	hvAb Penn.	hvC
Elemental analysis of ash (%)						
Silica (SiO2)	51-61	58.0	35.9	52.5	51.1	52.0
Aluminum Oxide (Al2O3)	2.9	29.1	18.9	18.9	30.7	17.5
Iron Oxide (Fe2O3)	3.0	3.6	6.1	1.1	10.0	15.5
Titanium Oxide (TiO2)	0.15-0.25	1.6	1.4	1.2	2.0	1.3
Calcium Oxide (CaO)	10-25	0.8	24.6	13.2	1.6	4.5
Magnesium Oxide (MgO)	2.0-3.6	0.8	5.4	1.3	0.9	1.1
Sodium Oxide (Na2O)	0.5	0.1	1.9	3.8	0.4	0.6
Potassium Oxide (K2O)	3.5-7.5	2.5	0.3	0.9	1.7	2.8
Sulfur Trioxide (SO3)	1.4-2.2	0.2	2.3	6.2	1.4	4.2
Phosphorus Pentoxide (P2O5)	1.2-2.4	0.1	1.1	--	--	0.1
Barium Oxide (BaO)	--	0.1	0.7	--	--	--
Manganese Oxide (Mn2O3)	0.046-0.072	0.1	<0.1	--	--	--
Strontium Oxide (SrO)	--	0.1	0.4	--	--	--
Trace metals (ppm):						
Arsenic	48					
Chlorine	26,000					
Lead	95					
Manganese	319-497					
Mercury	<0.1					

[a] Average or range of two bagasse samples which were ashed in the laboratory and analyzed for constituents. (Hazen Research, Inc, 2003).

Table 5-4. Cost Effectiveness of Tail-End SCR with ESP, Osceola Boiler No. 4 & No. 5.

Cost Items	Cost Factors[a]	Cost Per Boiler ($)
DIRECT CAPITAL COSTS (DCC):		
SCR Basic Process	Vendor quote[b]	737,376
Auxiliary Equipment (Reheat)	20% of SCR equipment cost, engineering estimate	147,475
Emission Monitoring	15% of SCR equipment cost	110,606
No. 2 Fuel Oil Storage Tank & Foundation	Engineering Estimate	100,000
Ammonia Storage System	Vendor quote[c], 10,000 gallon storage tank	170,000
Foundation and Structure Support	8% of equipment cost	72,590
Control Room and Enclosures	4% of equipment cost, engineering estimate	36,295
Transition Ducts to and from SCR	4% of equipment cost, engineering estimate	29,495
Wiring and Conduit	2% of equipment cost, engineering estimate	18,148
Insulation	2% of equipment cost, engineering estimate	18,148
Motor Control and Motor Starters	4% of equipment cost, engineering estimate	36,295
SCR Bypass Duct	$127 per MMBtu/hr	42,037
Induced Draft Fan	5% of SCR equiment cost, engineering estimate	36,869
Taxes	Florida sales tax, 6%	54,443
Total DCC:		1,609,777
INDIRECT CAPITAL COSTS (ICC):		
General Facilities	5% of DCC	80,489
Engineering Fees	10% of DCC	160,978
Performance test	1% of DCC	16,098
Process Contingencies	5% of DCC	80,489
Total ICC:		338,053
Project Contingencies:	35% of DCC, Retrofit	563,422
TOTAL CAPITAL INVESTMENT OF SCR (TCI):	DCC + ICC + Project Contingencies	2,511,252
TOTAL CAPITAL INVESTMENT OF ESP (TCI):	Refer to Table 5-5	1,877,062
TOTAL CAPITAL INVESTMENT		4,388,314
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	24 hrs/wk, $16/hr, 26 wks/yr	9,984
Supervisor	15% of operator cost	1,498
(2) Maintenance	Engineering estimate, 5% of catalyst replacement cost	2,458
(3) SCR Energy Requirement	163 Hp Blower, 16 Hp Ammonia Pump, 82kW/h for SCR @ $0.04/kWh	8,817
(4) Ammonia Cost	$495/ton NH3 19% Aqueous(Tanner,02)	108,949
(5) Reheat Energy Requirements	40 MMBtu/hr, 3840 hr/yr, $3/MMBtu	500,779
(6) Catalyst Replacement and disposal	$221,212 per catalyst[d], 17,520 hrs or every 4.5 years	49,158
Total DOC:		681,643
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	237,062
ANNUALIZED COSTS of SCR (AC):	DOC+ CRC	918,705
ANNUALIZED COSTS of ESP (AC):	Refer to Table 5-5	308,639
TOTAL ANNUALIZED COST		1,227,344
BASELINE NO_x EMISSIONS (TPY) :	228.6 TPY (Boiler 4 and 5 Combined) / 2;	114.3
MAXIMUM NO_x EMISSIONS (TPY) :	90% reduction	11.4
REDUCTION IN NO_x EMISSONS (TPY):		102.9
COST EFFECTIVENESS:	$ per ton of NO_x Removed	11,931

Footnotes:

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

[b] 2002 CSM Industries cost quote.

[c] Ammonia storage tank vendor's quotation for RM Technologies, for a 10,000-gallon anhydrous ammonia tank. Includes stainless steel horizontal tank, valves, and transfer station.

[d] SCR catalyst replacement based on CSM Industries catalyst quote and 17,520 hrs guarantee.

Table 5-5. Cost of Dry Electrostatic Precipitator for PM Control, Osceola Boiler No. 4 & No. 5

Cost Items	Cost Factors[a]	Cost Per Boiler ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
ESP.	Vendor Quote[b]	654,000
Ductwork to ESP inlet and oulct	10% of ESP, Engineering Estimate	65,400
Electrical switchgear, motor control centcrs	2% of ESP, Engineering Estimate	13,080
Instruments and Controls	Included	0
Freight	Vendor Quote[b]	30,000
Taxes	6% Sales Tax	39,240
Total PEC:		801,720
Direct Installation Costs		
Foundation and Structure Support	4% of PEC	32,069
Handling & Erection	Vendor Quote[b]	450,000
Electrical	8% of PEC	64,138
Piping	1% of PEC	8,017
Insulation for ductwork	2 % of PEC	16,034
Painting	2% of PEC	16,034
Total Direct Installation Costs		586,292
Total DCC:		1,388,012
INDIRECT CAPITAL COSTS (ICC):		
Contractor Fces +	10% of PEC	80,172
Performance test +	1% of PEC	8,017
Contingcncies	50% of PEC, OAQPS Retrofit Cost Factor	400,860
Total ICC:		489,049
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	1,877,062
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	21 hours/week, $16/hr, 26 weeks/yr	8,736
Supervisor	15% of operator cost	1,310
(2) Maintenance	Engineering estimate, 1% PEC	8,017
(4) Electricity - Fan	24.4 kW; $0.06/kWh; 3840 hr/yr	5,630
(5) Electricity - Purge Air System	33.1 kW; $0.06/kWh; 3840 hr/yr	7,626
(6) Electricity - Transformer-Rectifier Set	54.8 kW; $0.06/kWh, 3840 hr/yr	14,204
Total DOC:		45,523
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	10,838
Property Taxes	1% of total capital investment	18,771
Insurance	1% of total capital investment	18,771
Administration	2% of total capital investment	37,541
Total IOC:		85,921
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	177,195
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	308,639

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost I 0.026 lb/MMBtu; 1,140,480 MMBtu/yr

[b] Based on quote from Environmental Elements Corporation, (2003) for 425,000 acfm unit. OFC Boilers 4 and 5 will require 200,000 acfm units.

Table 5-6. Cost Effectiveness of SNCR, Osceola Farms Boiler Nos. 4 and 5

Cost Items	Cost Factors[a]	Total Cost for Both Boilers ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
SNCR Basic Process	Vendor quote[b]	1,600,000
Ammonia Storage Tank	10,000 gallon, includes transfer station; included	--
NOx Emissions Monitoring	15% of equipment cost	160,000
Foundation and Structure Support	8% of equipment cost	128,000
Freight	Vendor quote[b]	80,000
Taxes	Florida sales tax, 6%	96,000
Total PEC:		2,064,000
Direct SNCR Installation	Vendor quotes for similar boilers (equal to basic process equipment cost)	1,600,000
Total DCC:		3,664,000
INDIRECT CAPITAL COSTS (ICC):		
Air and Water Piping	Engineering Estimate	100,000
Electrical and Controls	Engineering Estimate	100,000
Performance testing	Based on historical testing	20,000
Contractor Fees	10% of DCC	366,400
Process Contingencies	5% of DCC	183,200
Total ICC:		769,600
PROJECT CONTINGENCY (Retrofit installation)	15% of (DCC+ICC)	665,040
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	5,098,640
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	20 hours/week, $16/hr, 52 weeks/yr	$16,640
Supervisor	15% of operator cost	2,496
(2) Maintenance	Engineering estimate, 2% Process Equipment	41,280
(3) NOxOut Cost	2 boilers @ 20 gal/hr each, $1.00/gal, 3,840 hr/yr	153,600
Total DOC:		214,016
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	36,250
Property Taxes	1% of total capital investment	50,986
Insurance	1% of total capital investment	50,986
Administration	2% of total capital investment	101,973
Total IOC:		240,195
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	481,312
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	935,523
BASELINE NO_x EMISSIONS (TPY) :	0.22 lb/MMBtu	228.6
MAXIMUM NO_x EMISSIONS (TPY) :	25% reduction	171.5
REDUCTION IN NO_x EMISSONS (TPY):		57.2
COST EFFECTIVENESS:	$ per ton of NO_x Removed	16,370

Footnotes:

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

[b] FuelTech, Inc. proposals for U.S. Sugar Boiler No. 8 and for confidential client, 2004.

Table 5-7. BACT Determinations for VOC Emissions From Biomass-Fired Industrial Boilers

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
U.S. Sugar Corp.--Clewiston Blr No. 8	FL	PSD-FL-333[b]	11/21/2003	1,030 MMBtu/hr	0.05 lb/MMBtu	0.05	Good combustion practices
New Hope Power Partnership	FL	FL-0069	1/31/2002	715 MMBtu/hr	0.06 lb/MMBtu	0.06	Clean fuels
S.D. Warren Co.--Blr No. 2	ME	ME-0021	11/27/2001	1,300 MMBtu/hr	0.007 lb/MMBtu	0.007	Good combustion practices
US Sugar Corp.--Clewiston Blr No. 4	FL	PSD-FL-272A[b]	5/18/2001	633 MMBtu/hr	0.50 lb/MMBtu	0.50	Good combustion practices
Atlantic Sugar Association--Blr No. 5	FL	PSD-FL-078B[b]	6/7/2001	255.3 MMBtu/hr	0.25 lb/MMBtu	0.25	Good Combustion Practices
Scott Paper Company	WA	WA-0276	10/14/1998	718 MMBtu/hr	34.5 lb/hr	0.05	Combustion control, boiler design
GULF STATES PAPER CORP	AL	AL-0122	10/14/1998	98 MMBtu/hr	0.1 lb/MMBtu	0.1	--
Sierra Pacific Industries--Quincy	CA	CA-0930	5/13/1998	245.3 MMBtu/hr	12.3 lb/hr	0.05	High pressure overfire air
GULF STATES PAPER CORPORATION	AL	AL-0116	12/10/1997	775 MMBtu/hr	0.03 lb/MMBtu	0.03	Proper boiler design and operation
Champion International	AL	AL-0112	12/9/1997	710 MMBtu/hr	0.03 lb/MMBtu	0.03	Good design and operation
MEAD CONTAINERBOARD	AL	AL-0099	1/15/1997	620 MMBtu/hr	0.03 lb/MMBtu	0.03	Combustion Control
Vaughan Furniture Company	VA	VA-0237	8/28/1996	28 MMBtu/hr	1.7 TPY	--	Combustion control, boiler design
Willamette Industries - Marlboro Mill	SC	SC-0045	4/17/1996	470 MMBtu/hr	0.1 lb/MMBtu	0.1	Good combustion control
SOUTHERN SOYA CORPORATION	SC	SC-0035	10/2/1995	58.2 MMBtu/hr	0.05 lb/MMBtu	0.05	Good combustion practices
PLUM CREEK MFG LP-COLUMBIA FALLS OP'N	MT	MT-0004	7/26/1995	50 MMBtu/hr	131.1 lb/hr	2.62	Good combustion practices
GEORGIA PACIFIC CORP. - GLOSTEE FACILITY	MS	MS-0023	4/11/1995	244 MMBtu/hr	0.02 lb/MMBtu	0.02	
U.S. SUGAR CORP--Clewiston Blr No. 7	FL	FL-0094[b]	1/31/1995	738 MMBtu/hr	0.212 lb/MMBtu	0.212	Good combustion practices
KES CHATEAUGAY PROJECT	NY	NY-0055	12/19/1994	275 MMBtu/hr	0.1 lb/MMBtu	0.1	No Controls
Plum Creek MFG LP-Columbia Falls Op'n	MT	MT-0004	10/28/1994	50 MMBtu/hr	131.1 lb/hr	2.6	Good combustion practices
WEYERHAEUSER CO.	AL	AL-0079	10/28/1994	91 MMBtu/hr	0.05 lb/MMBtu	0.05	
Weyerhaeuser Co.	AL	AL-0079	7/1/1993	91 MMBtu/hr	0.05 lb/MMBtu	0.05	--
Gulf States Paper Corp	AL	AL-0122	7/1/1993	98 MMBtu/hr	0.1 lb/MMBtu	0.1	--

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001.

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

[b] This information obtained from actual PSD permit, not Clearinghouse.

Table 5-8. Add-On VOC Control Technology Feasibility Analysis for Boiler Nos. 4 and 5

VOC Abatement Method	Technique Now Available	Estimated Efficiency	Technically Feasible? (Y/N)	Bagasse Demonstrated? (Y/N)	Rank Based on Control Efficiency	Employed by Boiler Nos. 4 and 5? (Y/N)
1. Refrigerated Condensors	Surface	Variable	N	NA	NA	N
	Contact	Variable	N	NA	NA	N
				NA	NA	N
2. Carbon Adsorbers	Fixed Regenerative bed	Variable	N	NA	NA	N
	Disposable/Rechargeable Cannisters	Variable	N	NA	NA	N
	Traveling Bed Adsorbers	Variable	N	NA	NA	N
	Fluid Bed Adsorbers	Variable	N	NA	NA	N
	Chromatographic Baghouse	Variable	N	NA	NA	N
				NA	NA	N
3. Destruction Controls	Flares	Variable	N	NA	NA	N
				NA	NA	N
4. Incinerators	Thermal	>80%	N	NA	NA	N
	Catalytic	>80%	N	NA	NA	N

Note: NA = Not Applicable

6.0 AIR QUALITY IMPACT ANALYSIS

This section presents the air quality modeling methodology and results. As described in Section 3.2.7.3, an air quality impact analysis for the proposed project is required for NO_x emissions.

6.1 SIGNIFICANT IMPACT ANALYSIS METHODOLOGY

6.1.1 SITE VICINITY

The general modeling approach followed EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For all criteria pollutants that will be emitted in excess of the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the emission and/or stack configuration changes due to the project alone will result in predicted impacts that are in excess of the EPA significant impact levels at any location beyond the plant's restricted boundaries.

If the project-only impacts are above the significant impact levels in the vicinity of the facility, then two additional and more detailed air modeling analyses are required. The first analysis demonstrates compliance with federal and Florida AAQS, and the second analysis demonstrates compliance with allowable PSD Class II increments.

6.1.2 PSD CLASS I AREAS

Generally, if the facility undergoing the modification is within 200 kilometers (km) of a PSD Class I area, then a significant impact analysis is also performed to evaluate the impact due to the project alone at the PSD Class I area. The PSD Class I area of Everglades National Park (ENP) is located approximately 120 km from the Osceola Farms Mill. Because ENP is located within 200 km of the Mill, the maximum predicted impacts at the ENP are compared to EPA's proposed significant impact levels for PSD Class I areas. These recommended levels have never been promulgated as rules, but are the currently accepted criteria to determine whether a proposed project will incur a significant impact on a PSD Class I area.

If the project-only impacts at the PSD Class I area are above the proposed EPA PSD Class I significant impact levels, then an analysis is performed to demonstrate compliance with allowable PSD Class I impacts at the PSD Class I area.

In addition, the project's maximum concentrations are evaluated at the PSD Class I area for pollutants whose emissions are greater than the significant emission rate, to address potential impacts on AQRVs. This analysis includes an evaluation of regional haze degradation and nitrogen deposition.

6.2 PRECONSTRUCTION MONITORING ANALYSIS METHODOLOGY

The modeling approach for Boiler Nos. 4 and 5 followed EPA and FDEP modeling guidelines for evaluating a project's impacts relative to the *de minimis* monitoring levels to determine the need to submit ambient monitoring data prior to construction. Current FDEP policies stipulate that the predicted highest annual average and highest short-term concentrations are to be compared to the applicable *de minimis* monitoring levels.

6.3 AIR MODELING ANALYSIS METHODOLOGY

6.3.1 GENERAL PROCEDURES

As stated in the previous sections, for each pollutant which is emitted above the significant emission rate, air modeling analyses are required to determine if the project-only impacts are predicted to be greater than the significant impact levels and *de minimis* monitoring levels. These analyses consider impacts due to the proposed project alone. Air quality impacts are predicted using 5 years of meteorological data and then selecting the highest predicted ground-level concentrations for comparison to the significant impact levels and *de minimis* monitoring levels.

To predict the maximum annual and short-term concentrations for the proposed Boiler Nos. 4 and 5 modification, the modeling approach was divided into screening and refined phases. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record. If the highest concentration is predicted at a receptor that lies in an area where the receptor spacing is more than 100 meters (m), then a refined analysis is performed in that area using a receptor grid of greater resolution. Modeling refinements are performed using a receptor spacing of 100 m or less with a receptor grid centered on the screening receptor at which the maximum concentration was predicted. The air dispersion model is then executed with the refined grid for the entire year of meteorology during which the screening concentration occurred.

If the modification's impacts are greater than the significant impact levels, the air modeling analyses must consider other nearby sources and background concentrations to predict total concentrations for comparison to AAQS and PSD increments.

Generally, when using five years of meteorological data for the analysis, the highest annual and the HSH short-term concentrations are compared to the applicable AAQS and allowable PSD increments. [Note that for determining compliance with the 24-hr AAQS for PM_{10}, the sixth highest predicted concentration in 5 years (i.e., H6H), instead of the HSH, is used for comparison to the applicable 24-hr AAQS.]

The HSH concentration 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.

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

The AAQS analysis is a cumulative source analysis that evaluates whether the concentrations from all sources will comply with the AAQS. These concentrations include the modeled impacts from sources at the project site and from other nearby facility sources added to a background concentration. The background concentration accounts for sources not included in the modeling analysis.

The PSD Class II analysis is a cumulative source analysis that evaluates whether the concentrations for increment-affecting sources will comply with the allowable PSD Class II increments. These concentrations include the modeled impacts from PSD increment-affecting sources at the project site, plus nearby PSD increment-affecting sources at other facilities.

6.3.2 PSD CLASS I ANALYSIS

For each pollutant for which a significant impact is predicted at the PSD Class I area, a PSD Class I analysis is required. The PSD Class I analysis is a cumulative source analysis that evaluates whether the concentrations for increment-affecting sources located within 200 km of the PSD Class I area will comply with the allowable PSD Class I increments. These concentrations include the impacts from PSD increment-affecting sources at the project site, plus the impacts from PSD increment-affecting sources at other facilities.

6.4 MODEL SELECTION

The selection of an air quality model to calculate air quality impacts was based on its applicability to simulate impacts in areas surrounding Osceola Farms, as well as at the PSD Class I area of interest. Two air quality dispersion models were selected and used in these analyses to address air quality impacts for the proposed Boiler Nos. 4 and 5 modification. These models were:

- The Industrial Source Complex Short Term (ISCST3) dispersion model; and
- The California Puff model (CALPUFF).

The ISCST3 model, Version02035 (EPA 2002), is maintained by the EPA on its Internet website, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). A listing of ISCST3 model features is presented in Table 6-1. 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.

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The ISCST3 model can be executed in the rural or urban land use mode that 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 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 the land use within a 3-km radius of Osceola Farms, the rural dispersion coefficients were used in the modeling analysis. Also, since the terrain around the facility is flat, the simple terrain feature of the model was selected. The ISCST3 model was used to provide maximum concentrations for the annual and 24-, 8-, 3-, and 1-hr averaging times.

At distances beyond 50 km from a source, the CALPUFF model, Version 5.7 (EPA, 2003), is recommended for use by the EPA and the Federal Land Manager (FLM). Major features of the CALPUFF model are presented in Table 6-2. The CALPUFF model is a long-range transport model used for estimating the air quality impacts in areas that are more than 50 km from a source. The

CALPUFF model is maintained by the EPA on the SCRAM internet website. The methods and assumptions used in the CALPUFF model are based on the latest recommendations for modeling analysis as presented in the following reports:

- The Interagency Workgroup on Air Quality Models (IWAQM), *Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998); and
- The *Federal Land Manager's Air Quality Relative Values Workgroup (FLAG) Phase I Report* (December, 2000).

In addition, updates to the modeling methods and assumptions were followed based on discussion with the FLM.

The CALPUFF model was used to perform a significant impact analysis for the proposed project at the PSD Class I area of ENP and to assess the project's impact on regional haze and total nitrogen and sulfur deposition levels. A more detailed description of the assumptions and methods used for the CALPUFF model is presented in Appendix E.

6.5 METEOROLOGICAL DATA

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). The 5-year period of meteorological data was from 1987 through 1991. The NWS office at PBI is located approximately 47-km east of the site and is the closest primary weather station to the study area considered to have meteorological data representative of the site. The PBI station meteorological data have been used for numerous air modeling studies submitted as part of air construction permits approved for sources located in Palm Beach County.

CALMET, the meteorological preprocessor to CALPUFF, was used to develop a 3-dimensional wind field necessary to perform the air modeling analysis to evaluate pollutant impacts at each PSD Class I area. The modeling domain consisted of a rectangular 3-dimensional grid that extended from approximately 79.0- to 83.5-degrees longitude and from 23.75- to 28.0-degrees latitude.

The modeling domain includes the following meteorological and land use parameters:

Surface weather data,

- Upper air data,
- 1-degree land use data,
- 1-degree Digital Elevation Model (DEM) terrain data,
- Mesoscale Model - Generation 4 (MM4) data (for initializing the wind field) for 1990,
- MM5 data for 1992 and 1996, and
- Hourly precipitation data.

These data were obtained and processed for the calendar years 1990, 1992, and 1996, the years for which MM4 and MM5 data are available on CD. The CALMET wind field and the CALPUFF model options used for the Boiler Nos. 4 and 5 analysis were consistent with the suggestions of the FLMs. Meteorological data used with the CALPUFF model consist of a CALMET-developed wind field covering south Florida. More detailed descriptions of the assumptions and methods used for processing the meteorological data and establishing the model domain are presented in Appendix E.

6.6 EMISSION INVENTORY

6.6.1 SIGNIFICANT IMPACT ANALYSIS

The proposed project will result in a significant net emissions increase for NO_x. Baseline (current actual) emissions for Boiler Nos. 4 and 5, used in the significant impact analysis are shown in Table 3-3 and Tables B-1 through B-6 (annual emissions) and in Tables B-7 and B-8 (short-term emissions). Current stack parameters are shown in Table 2-6. The proposed future emissions and stack parameters for Boiler Nos. 4 and 5 are summarized in Tables 2-2 through 2-6. Because there were separate short-term and annual NO_x emission rates (to address impacts to AQRVs), separate modeling runs were performed for the appropriate averaging periods.

Osceola Farms Boiler Nos. 4 and 5 are restricted to operate during the period of October through April. In fact, all boilers at the Osceola mill are restricted to operating during this time period, and this period represents the actual past operation of the boilers. Thus, the NO_x impacts were predicted using the monthly emission factor option by specifying the boilers as operating from October to April (monthly emission factor is equal to 1) and not operating from May to September (monthly emission factor is equal to 0).

In addition, for the actual past operations of the boilers, the annual emissions were assumed to occur from October through April (assuming 5,088 hours). For future operations of Boiler Nos. 4 and 5, the annual emissions were assumed to occur for 3,840 hours (maximum proposed hours) but modeled for the entire period of October to April.

For the PSD Class I area of the ENP, concentrations were predicted for the project with the CALPUFF model based on the operating scenario with the maximum hourly emissions. The Osceola mill's Universal Transverse Mercator (UTM) east and north coordinates were specified to be 544,700 and 2,967,300 m, respectively, in UTM Zone 17.

6.6.2 AAQS AND PSD CLASS II ANALYSES

As discussed in Section 6.10, the maximum impacts from the proposed project were predicted to be greater than the significant impact levels for NO_2. As a result, a cumulative source analysis is required to demonstrate compliance with the NO_2 AAQS and PSD Class II increments.

The significant impact distance for NO_2 was determined to be less than 4 km. Therefore, the screening area for modeling was selected as 54 km surrounding the Osceola Farms site. A listing of background NO_x sources considered in the AAQS and PSD Class II modeling analyses and their locations relative to Osceola Farms is provided in Table 6-3.

All facilities in the screening area were evaluated using the North Carolina screening technique. Based on this technique, facilities whose annual (i.e., tons per year) emissions are less than the threshold quantity, Q, are eliminated from the modeling analysis. Q is equal to 20 x (D-SIA), where D is the distance in kilometers from the facility to Osceola Farms, and SIA is the distance of the proposed project's NO_x significant impact area (4 km). The NO_x facilities that were not eliminated in the screening analysis are available for inclusion in the AAQS and/or PSD Class II analyses. It is noted that large sources (>1,000 TPY NO_x) located beyond the screening area were also included in the modeling analysis.

Detailed NO_x background source data that were used for the AAQS and PSD Class II analyses are presented in Appendix F. Data for non-Osceola Farms NO_x sources were obtained from FDEP and were supplemented with current and historical information available within Golder.

6.6.3 PSD CLASS I ANALYSIS

The maximum project-only impacts at the PSD Class I area of the ENP are predicted to be less than the proposed Class I significant impact levels for all pollutants. As a result, a cumulative source impact analysis is not required to demonstrate compliance with the PSD Class I increments.

6.7 RECEPTOR LOCATIONS

6.7.1 SITE VICINITY

To determine the NO_2 significant impact area for the proposed project, concentrations were predicted using polar receptor grids. The receptor grids were comprised of 36 radials, spaced at 10-degree intervals and began at the plant property and extended out to 30 km. An additional 182 Cartesian grid receptors, spaced at 100 m, were used to predict impacts along the fence line areas. A listing of the fence line receptors is presented in Table 6-4 and are depicted graphically in Figures 6-1 and 6-2.

At the off-property areas between the fence line and the innermost ring distance of 4.0 km, 67 discrete polar receptors were used, spaced at 10-degree intervals and at distances of 1.5, 2.0, and 3.0 km from the origin. Based on the results of the significant impact analysis, a maximum receptor distance of 4 km was used for NO_2 for the screening grids for the AAQS and PSD Class II analyses.

6.7.2 CLASS I AREA

Maximum pollutant concentrations were predicted with the CALPUFF model using 126 discrete receptors located along the border of the PSD Class I area of the ENP. These receptors were also used in the AQRV analysis to address the project's impacts on regional haze and sulfur and nitrogen deposition. A listing of Class I receptors used in the modeling analysis is provided in Table 6-5.

6.8 BACKGROUND CONCENTRATIONS

To estimate total air quality concentrations in the site vicinity, a background concentration must be added to the AAQS modeling results. The background concentration is considered to be the air quality concentration contributed by sources not explicitly included in the modeling evaluation.

The derivation of the background concentrations for the modeling analysis is presented in Section 4.0. Based on this analysis, the background annual average NO_2 concentration was determined to be 32 $\mu g/m^3$.

This background level was added to model-predicted concentrations to estimate total air quality levels for comparison to AAQS.

6.9 BUILDING DOWNWASH EFFECTS

All significant building structures within the Osceola Farms mill were determined by a site plot plan. The plot plan of the site is presented in Section 2.0. A listing of dimensions for each structure is presented in Table 6-6.

All building structures were processed in the EPA Building Input Profile (BPIP, Version 95086) program to determine direction-specific building heights and widths for each 10-degree azimuth direction for each source included in the modeling analysis. The significant structure most influencing the boiler stacks at Osceola Farms mill is the Boiling House/Mill structure. A graphical depiction of the building structures and stack locations, as well as the modeling origin, is presented in Figure 6-3. BPIP model input and output files are presented in Appendix G.

6.10 MODEL RESULTS

6.10.1 PSD CLASS II SIGNIFICANT IMPACT ANALYSIS

The maximum annual average NO_2 concentrations predicted for the project only for the PSD Class II significant impact analysis are presented in Table 6-7. The maximum annual average NO_2 impacts were determined to be significant for the proposed project. The significant impact distance was determined to be 3 km. The summaries of the ISCST3 results with example input files are presented in Appendix H.

6.10.2 AAQS ANALYSIS

A summary of the maximum predicted annual average NO_2 impacts for the modeling analysis, due to all sources from the screening analysis, is presented in Table 6-8. Since the maximum NO_2 concentrations were predicted along the property boundary where receptors were spaced at 100-m intervals, refined modeling was not necessary. The maximum annual average NO_2 concentration is predicted to be 51.0 $\mu g/m^3$. This concentration includes an ambient non-modeled annual background concentration of 32 $\mu g/m^3$. The maximum predicted annual average NO_2 concentration is below the Florida AAQS of 100 $\mu g/m^3$.

6.10.3 PSD CLASS II ANALYSIS

The maximum PSD Class II increment concentrations for NO_2 predicted for the project are presented in Table 6-9. Similar to the AAQS analysis, refined modeling was not necessary since the maximum NO_2 concentrations were predicted along the property boundary where receptors were spaced at 100-m intervals. The maximum annual average NO_2 increment consumption concentration is predicted to be 10.4 $\mu g/m^3$ which is less than the allowable PSD Class II increment of 25 $\mu g/m^3$.

6.10.4 PSD CLASS I SIGNIFICANT IMPACT ANALYSIS

The maximum annual average NO_x concentrations predicted for the project for the PSD Class I significant impact analysis at the ENP are presented in Table 6-10. All of the maximum impacts are predicted to be below the PSD Class I significant impact levels.

Because the proposed project's impacts are predicted to be below the PSD Class I significant impact levels for all pollutants, additional modeling analyses are not required to be performed to address compliance with PSD Class I increments.

6.10.5 CONCLUSIONS

Based on the air quality modeling analyses, the maximum pollutant concentrations due to the proposed Boiler Nos. 4 and 5 modification's emissions demonstrate compliance with AAQS and PSD increments. The results of the modeling analysis demonstrate the proposed project will comply with all applicable AAQS and PSD increments.

Table 6-1. Major Features of the ISCST3 Model, Version 02035

ISCST3 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: ISCST3 = Industrial Source Complex Short-Term

References:

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Schulman, L.L. and J.S. Scire. 1980. Buoyant Line and Point Source (BLP) Dispersion Model User's Guide. Document P-7304B. Environmental Research and Technology, Inc., Concord. MA.

Table 6-2. Major Features of the CALPUFF Model, Version 5.7

CALPUFF Model Features

- Source types: Point, line (including buoyancy effects), volume, area (buoyant, non-buoyant).
- Non-steady-state emissions and meteorological conditions (time-dependent source and emission data; gridded 3-dimensional wind and temperature fields; spatially-variable fields of mixing heights, friction velocity, precipitation, Monin-Obukhov length; vertically and horizontally-varying turbulence and dispersion rates; time-dependent source and emission data for point, area, and volume sources; temporal or wind-dependent scaling factors for emission rates).
- Efficient sampling function [integrated puff formulation; elongated puff (slug) formation].
- Dispersion coefficient options [Pasquill-Gifford (PG) values for rural areas; McElroy-Pooler values (MP) for urban areas; CTDM values for neutral/stable; direct measurements or estimated values].
- Vertical wind shear (puff splitting; differential advection and dispersion).
- Plume rise (buoyant and momentum rise; stack-tip effects; building downwash effects; partial plume penetration above mixing layer).
- Building downwash effects (Huber-Snyder method; Schulman-Scire method).
- Complex terrain effects (steering effects in CALMET wind field; puff height adjustments using ISC model method or plume path coefficient; enhanced vertical dispersion used in CTDMPLUS).
- Subgrid scale complex terrain (CTSG option) (CTDM flow module; dividing streamline as in CTDMPLUS).
- Dry deposition (gases and particles; options for diurnal cycle per pollutant, space and time variations with a resistance model, or none).
- Overwater and coastal interaction effects [overwater boundary layer parameters; abrupt change in meteorological conditions, plume dispersion at coastal boundary; fumigation; option to use Thermal Internal Boundary Layers (TIBL) into coastal grid cells].
- Chemical transformation options [Pseudo-first-order chemical mechanisms for SO_2, SO_4, HNO_3, and NO_3; Pseudo-first-order chemical mechanisms for SO_2, SO_4, NO, NO_2, HNO_3, and NO_3 (RIVAD/ARM3 method); user-specified diurnal cycles of transformation rates; no chemical conversions].
- Wet removal (scavenging coefficient approach; removal rate as a function of precipitation intensity and type).
- Graphical user interface.
- Interface utilities (scan ISC-PRIME and AUSPLUME meteorological data files for problems; translate ISC-PRIME and AUSPLUME input files to CALPUFF input files).

Note: CALPUFF = California Puff Model.

Source: EPA, 2003.

Table 6-3. Summary of NO_x Facilities Considered for Inclusion in the AAQS and PSD Class II Air Modeling Analyses.

APIS Number	Facility	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to Osceola Farms[a] X (km)	Y (km)	Distance (km)	Direction (deg)	Maximum NO_x Emissions (TPY)	Q, Emission Threshold (Dist -4) x 20	Include in Modeling Analysis[b] ?
0990061	U.S.SUGAR CORP. BRYANT MILL	537.8	2969.1	-6.9	1.8	7.1	285	1,984	62.7	YES
0990026	SUGAR CANE GROWERS CO-OP	534.9	2953.3	-9.8	-14.0	17.1	215	3,243	261.8	YES
0990594	El Paso Belle Glade Generating Station	533.5	2954.1	-11.2	-13.2	17.3	220	365	266.2	YES
0990021	UNITED TECHNOLOGIES CORP. (PRATT & WHITNEY)	562.0	2976.0	17.3	8.7	19.4	63	1,756	307.3	YES
0990530	HUBBARD CONSTRUCTION COMPANY	562.1	2955.6	17.4	-11.7	21.0	124	30	340.5	NO
0850129	AMERICAN POWER TECH, INC	549.1	2990.8	4.4	23.5	23.9	11	10	398.2	NO
0850102	INDIANTOWN COGENERATION, L.P.	545.6	2991.5	0.9	24.2	24.2	2	2,583	404.3	YES
0990566	INDIAN TRAIL IMPROVEMENT DISTRICT	564.7	2956.2	20.0	-11.1	22.9	119	22	377.7	NO
0990185	SIKORSKY AIRCRAFT (PRATT & WHITNEY)	567.5	2975.0	22.8	7.7	24.1	71	3	401.3	NO
0990016	ATLANTIC SUGAR ASSOCIATION	552.9	2945.2	8.2	-22.1	23.6	160	2,266	391.4	YES
0990086	GLADES CORRECTIONAL	523.4	2955.2	-21.3	-12.1	24.5	240	15	409.9	NO
0850001	FP&L MARTIN	543.1	2992.9	-1.6	25.6	25.6	356	35,489	433.0	YES
0990529	PALM BEACH WOOD PRODUCTS, INC.	563.5	2952.1	18.8	-15.2	24.2	129	100	404.1	NO
0990549	SOUTH FLORIDA WMD--PUMP STN. G-310/S-6/S-9	554.2	2940.5	9.5	-26.9	28.5	161	396	489.6	NO
0990213	JUPITER MULCH, INC.	573.1	2980.1	28.4	12.8	31.1	66	26	542.9	NO
0990332	NEW HOPE POWER PARTNERSHIP (OKEELANTA PWR.)	524.1	2940.0	-20.6	-27.3	34.2	217	863	604.0	YES
0990005	OKEELANTA CORP. --only Blr. 16 included in future	525.0	2937.4	-19.7	-29.9	35.8	213	976	636.1	YES
0510001	EVERGLADES SUGAR	509.6	2954.2	-35.1	-13.1	37.5	250	1,410	669.3	YES
0990087	RANGER CONSTRUCTION INDUSTRIES, INC.	579.9	2951.7	35.2	-15.6	38.5	114	24	690.0	NO
0990583	MAGNUM ENVIRONMENTAL SERVICES, INC.	580.2	2952.0	35.5	-15.3	38.7	113	29	693.1	NO
0510003	U.S. SUGAR CORP. CLEWISTON MILL	506.1	2956.9	-38.6	-10.40	40.0	255	2,118	719.5	YES
0990234	SOLID WASTE AUTHORITY OF PBC	584.5	2961.3	39.8	-6.0	40.2	99	1,766	724.9	YES
0990233	MARKS LANDSCAPING & PAVING	582.1	2952.3	37.4	-15.0	40.3	112	100	725.9	NO
0990333	FLORIDA GAS TRANSMISSION	584.4	2957.1	39.7	-10.2	41.0	104	78	739.2	NO
0990300	PALM BEACH CO ANIMAL CARE AND CONTROL.	582.8	2952.2	38.1	-15.1	40.9	112	0	738.8	NO
7775057	CRUSHER CONTRACTORS CO.	582.5	2951.2	37.8	-16.1	41.1	113	11	741.8	NO
0990350	SOUTH FLORIDA WMD--PUMP STN. G-335	552.6	2922.0	7.9	-45.3	46.0	170	197	839.9	NO
0990522	PALM BEACH TRANSFER & RECYCLING,INC.	583.7	2951.5	39.0	-15.8	42.1	112	91	762.4	NO
0990304	DEPARTMENT OF VETERANS AFFAIRS	588.0	2963.0	43.3	-4.3	43.5	96	2	790.3	NO
0990562	SOUTH FLORIDA SHAVINGS CO.	579.2	2941.1	34.5	-26.2	43.3	127	2	786.4	NO
0990344	PARKWAY ASPHALT, INC.	588.5	2962.1	43.8	-5.2	44.1	97	19	802.2	NO
0990188	ANIMAL RESCUE LEAGUE	588.6	2956.0	43.9	-11.3	45.3	104	0	826.6	NO
0990123	FLORIDA POWER & LIGHT (PDC/OSF)	589.7	2961.2	45.0	-6.1	45.4	98	16	828.2	NO
0850017	TURBO COMBUSTOR TECHNOLOGY	576.6	3004.4	31.9	37.1	48.9	41	1	898.1	NO
0990056	ST. MARY'S HOSPITAL, INC.	593.0	2959.7	48.3	-7.6	48.9	99	11	897.9	NO
0850021	STUART CONTRACTING	575.2	3006.8	30.5	39.5	49.9	38	ND	918.1	NO

Table 6-3. Summary of NO_x Facilities Considered for Inclusion in the AAQS and PSD Class II Air Modeling Analyses.

APIS Number	Facility	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to Osceola Farms[a] X (km)	Y (km)	Distance (km)	Direction (deg)	Maximum NO_x Emissions (TPY)	Q, Emission Threshold (Dist -4) x 20	Include in Modeling Analysis[b] ?
0990325	ROYAL PALM MEMORIAL GARDENS, INC.	593.4	2960.2	48.7	-7.1	49.2	98	1	904.3	NO
0850015	AYCOCK FUNERAL HOME	573.5	3008.4	28.8	41.1	50.2	35	1	923.7	NO
0990042	FP&L RIVIERA [c]	594.2	2960.6	49.5	-6.7	50.0	98	16,565	919.0	YES
1110103	CPV Cana, LTD.	550.9	3018.1	6.2	50.8	51.2	7	102	943.5	NO
0990045	LAKE WORTH UTILITIES [c]	592.8	2943.7	48.1	-23.6	53.6	116	7,025	991.6	YES
0990568	LAKE WORTH GENERATION	592.8	2943.7	48.1	-23.6	53.6	116	395	991.6	NO
0510015	SOUTHERN GARDENS CITRUS	487.6	2957.6	-57.1	-9.7	57.9	260	102	1078.4	NO
0112534	Enron/Deerfield Beach Energy Center	583.1	2907.9	38.4	-59.4	70.7	147	572	1334.6	NO
0112545	El Paso Broward Energy Center	583.3	2908.0	38.6	-59.3	70.8	147	505	1335.1	NO
1110003	FT PIERCE UTILITIES AUTHORITY [c]	566.1	3036.4	21.4	69.0	72.3	17	1,215	1365.9	YES
0112120	WHEELABRATOR NORTH BROWARD [c]	583.9	2907.6	39.2	-59.7	71.4	147	2,060	1348.4	YES
0112515	Enron/Pompano Energy Center	583.7	2905.4	39.0	-61.9	73.2	148	573	1383.2	NO
0610029	CITY OF VERO BEACH [c]	561.4	3056.5	16.7	89.2	90.7	11	4,315	1735.0	YES
0112119	SOUTH BROWARD RRF [c]	579.6	2883.3	34.9	-84.0	91.0	157	1,497	1739.2	YES
0110037	FLORIDA POWER & LIGHT--LAUDERDALE [c]	580.1	2883.3	35.4	-84.0	91.2	157	14,025	1743.1	YES
0110036	FLORIDA POWER & LIGHT--PORT EVERGLADES [c]	587.4	2885.3	42.7	-82.0	92.5	152	25,217	1769.0	YES
0550018	TAMPA ELECTRIC CO.--PHILLIPS [c]	464.3	3035.4	-80.4	68.1	105.4	310	5,016	2027.3	YES
0250020	TARMAC AMERICA CO. [c]	562.9	2861.7	18.2	-105.6	107.2	170	3,473	2063.1	YES
0250348	MIAMI DADE RRF [c]	563.8	2857.6	19.1	-109.7	111.3	170	2,644	2146.7	YES
0550004	TECO--SEBRING/DINNER LAKE	456.8	3042.5	-87.9	75.2	115.7	311	369	2233.6	NO
0360119	LEE COUNTY RRF	424.2	2945.7	-120.5	-21.6	122.4	260	320	2368.2	NO
0710002	FP&L FORT MYERS [c]	422.1	2952.9	-122.6	-14.4	123.4	263	33,272	2388.9	YES

[a] Osceola Farms Coordinates 544.7 2967.3

[b] Emission inventory is limited to facilities within 54 km (project screening area).

[c] Large emission source (>1,000 TPY) outside the screening area that was included in the modeling analysis.

Table 6-4. Osceola Farms. Property Boundary Receptors[a] Used In the Modeling Analysis

Coordinates[b]		Coordinates[b]		Coordinates[b]		Coordinates[b]		Coordinates[b]	
X (m)	Y (m)	X (m)	Y (m)	X (m)	Y (m)	X (m)	Y (m)	X (m)	Y (m)
-1,219.2	2,987.0	2,580.8	2,987.0	1,950.7	141.9	792.0	-1,767.8	-1,219.2	21.0
-1,119.2	2,987.0	2,680.8	2,987.0	1,950.7	41.9	692.0	-1,767.8	-1,219.2	121.0
-1,019.2	2,987.0	2,743.2	2,949.4	1,950.7	-58.1	592.0	-1,767.8	-1,219.2	221.0
-919.2	2,987.0	2,743.2	2,849.4	1,950.7	-158.1	492.0	-1,767.8	-1,219.2	321.0
-819.2	2,987.0	2,743.2	2,749.4	2,025.9	-182.9	392.0	-1,767.8	-1,219.2	421.0
-719.2	2,987.0	2,743.2	2,649.4	2,125.9	-182.9	365.8	-1,694.1	-1,219.2	521.0
-619.2	2,987.0	2,743.2	2,549.4	2,225.9	-182.9	365.8	-1,594.1	-1,219.2	621.0
-519.2	2,987.0	2,743.2	2,449.4	2,316.5	-192.3	365.8	-1,494.1	-1,219.2	721.0
-419.2	2,987.0	2,743.2	2,349.4	2,316.5	-292.3	365.8	-1,394.1	-1,219.2	821.0
-319.2	2,987.0	2,743.2	2,249.4	2,316.5	-392.3	365.8	-1,294.1	-1,219.2	921.0
-219.2	2,987.0	2,743.2	2,149.4	2,316.5	-492.3	365.8	-1,194.1	-1,219.2	1,021.0
-119.2	2,987.0	2,743.2	2,049.4	2,316.5	-592.3	365.8	-1,094.1	-1,219.2	1,121.0
-19.2	2,987.0	2,743.2	1,949.4	2,316.5	-692.3	335.7	-1,024.1	-1,219.2	1,221.0
80.8	2,987.0	2,743.2	1,849.4	2,316.5	-792.3	235.7	-1,024.1	-1,219.2	1,321.0
180.8	2,987.0	2,743.2	1,749.4	2,316.5	-892.3	135.7	-1,024.1	-1,219.2	1,421.0
280.8	2,987.0	2,743.2	1,649.4	2,316.5	-992.3	35.7	-1,024.1	-1,219.2	1,521.0
380.8	2,987.0	2,743.2	1,549.4	2,248.3	-1,024.1	-64.3	-1,024.1	-1,219.2	1,621.0
480.8	2,987.0	2,743.2	1,449.4	2,148.3	-1,024.1	-164.3	-1,024.1	-1,219.2	1,721.0
580.8	2,987.0	2,743.2	1,349.4	2,048.3	-1,024.1	-264.3	-1,024.1	-1,219.2	1,821.0
680.8	2,987.0	2,743.2	1,249.4	1,948.3	-1,024.1	-364.3	-1,024.1	-1,219.2	1,921.0
780.8	2,987.0	2,673.4	1,219.2	1,848.3	-1,024.1	-464.3	-1,024.1	-1,219.2	2,021.0
880.8	2,987.0	2,573.4	1,219.2	1,748.3	-1,024.1	-564.3	-1,024.1	-1,219.2	2,121.0
980.8	2,987.0	2,473.4	1,219.2	1,648.3	-1,024.1	-664.3	-1,024.1	-1,219.2	2,221.0
1,080.8	2,987.0	2,373.4	1,219.2	1,548.3	-1,024.1	-764.3	-1,024.1	-1,219.2	2,321.0
1,180.8	2,987.0	2,273.4	1,219.2	1,448.3	-1,024.1	-864.3	-1,024.1	-1,219.2	2,421.0
1,280.8	2,987.0	2,173.4	1,219.2	1,348.3	-1,024.1	-964.3	-1,024.1	-1,219.2	2,521.0
1,380.8	2,987.0	2,073.4	1,219.2	1,249.7	-1,025.5	-1,064.3	-1,024.1	-1,219.2	2,621.0
1,480.8	2,987.0	1,973.4	1,219.2	1,249.7	-1,125.5	-1,164.3	-1,024.1	-1,219.2	2,721.0
1,580.8	2,987.0	1,950.7	1,141.9	1,249.7	-1,225.5	-1,219.2	-979.0	-1,219.2	2,821.0
1,680.8	2,987.0	1,950.7	1,041.9	1,249.7	-1,325.5	-1,219.2	-879.0	-1,219.2	2,921.0
1,780.8	2,987.0	1,950.7	941.9	1,249.7	-1,425.5	-1,219.2	-779.0		
1,880.8	2,987.0	1,950.7	841.9	1,249.7	-1,525.5	-1,219.2	-679.0		
1,980.8	2,987.0	1,950.7	741.9	1,249.7	-1,625.5	-1,219.2	-579.0		
2,080.8	2,987.0	1,950.7	641.9	1,249.7	-1,725.5	-1,219.2	-479.0		
2,180.8	2,987.0	1,950.7	541.9	1,192.0	-1,767.8	-1,219.2	-379.0		
2,280.8	2,987.0	1,950.7	441.9	1,092.0	-1,767.8	-1,219.2	-279.0		
2,380.8	2,987.0	1,950.7	341.9	992.0	-1,767.8	-1,219.2	-179.0		
2,480.8	2,987.0	1,950.7	241.9	892.0	-1,767.8	-1,219.2	-79.0		

[a] Receptors were selected at 100-meter spacing along property boundary.

[b] Distances are relative to the midpoint of the former Palm Beach Power Corp. Boiler Nos. 1 and 2., which is the modeling origin (0,0).

Table 6-5. Everglades National Park Receptors Used in the PSD Class I Modeling Analysis

UTM Coordinates (m)		UTM Coordinates (m)		UTM Coordinates (m)		UTM Coordinates (m)	
East	North	East	North	East	North	East	North
557000	2789000	538000	2848600	514500	2837000	470000	2860000
556600	2792000	537000	2848600	514500	2836000	469000	2860000
556000	2796000	536000	2848600	514500	2835000	468000	2860000
553000	2796500	535000	2848600	514500	2834000	467000	2860000
548000	2796500	534000	2848600	514500	2833000	466000	2860000
542700	2796500	533000	2848600	514500	2832500	465000	2860000
542700	2800000	532000	2848600	510000	2832500	464000	2860000
542700	2805000	531000	2848600	509000	2832500	463000	2860000
542700	2810000	530000	2848600	508000	2832500	462000	2860000
542000	2811000	529000	2848600	507000	2832500	461000	2860000
541300	2814000	528000	2848600	506000	2832500	460000	2860000
542700	2816000	527000	2848600	505000	2832500	459500	2863200
544100	2820000	526000	2848600	504000	2832500	459000	2863200
543500	2824600	525000	2848600	503000	2832500	458000	2863200
545000	2829000	524000	2848600	502000	2832500	457000	2863200
545700	2832200	523000	2848600	501000	2832500	456000	2863200
546200	2835700	522000	2848600	500000	2832500	455000	2863200
548600	2837500	521000	2848600	499000	2832500	454000	2863200
550300	2839000	520000	2848600	498000	2832500		
545000	2839000	519000	2848600	497000	2832500		
540000	2839000	518000	2848600	496000	2832500		
550500	2844000	517000	2848600	495000	2832500		
545000	2844000	516000	2848600	495000	2833000		
540000	2844000	515000	2848600	495000	2834000		
550300	2848600	514500	2848600	495000	2835000		
549000	2848600	514500	2848000	495000	2836000		
548000	2848600	514500	2847600	494500	2837000		
547000	2848600	514500	2846600	491500	2841000		
546000	2848600	514500	2845000	488500	2845500		
545000	2848600	514500	2844000	483000	2848500		
544000	2848600	514500	2843000	480000	2852500		
543000	2848600	514500	2842000	475000	2854000		
542000	2848600	514500	2841000	473500	2857000		
541000	2848600	514500	2840000	473000	2860000		
540000	2848600	514500	2839000	472000	2860000		
539000	2848600	514500	2838000	471000	2860000		

Note: Osceola Farm's coordinates are 544,700 m E, 2,967,300 m N.
m = meter

Table 6-6. Osceola Farms Building Dimensions Used in the Modeling Analysis

Structure	Height		Length		Width	
	ft	m	ft	m	ft	m
Osceola Farms Boiling House/Mill	70	21.3	302	92.0	230	70.0

Table 6-7. Maximum Predicted NO_2 Impacts Due to the Proposed Project Only - Osceola Farms

Rank/ Averaging Time	Concentration [a] (µg/m³)	Receptor Location [b] Direction (degrees)	Receptor Location [b] Distance (m)	Time Period (YYMMDDHH)	EPA Significant Impact Level (µg/m³)
Highest Annual Arithmetic Mean	0.80	271.0	1,219.4	87123124	1
	1.27	271.0	1,219.4	88123124	
	0.95	275.7	1,225.2	89123124	
	1.82	271.0	1,219.4	90123124	
	1.01	266.3	1,221.8	91123124	

Note: YYMMDDHH = Year, Month, Day, Hour Ending

[a] Concentrations are based on highest concentrations predicted using five years of surface and upper air meteorological data for 1987 to 1991 from the National Weather Service station at Palm Beach International Airport.

[b] Locations are relative to the midpoint of the former Palm Beach Power Corp. Boiler Nos. 1 and 2, which is the modeling origin (0,0).

Table 6-8. Maximum Predicted NO_2 Concentrations for All Sources Compared to the AAQS - Osceola Farms

Rank/ Averaging Time	Concentration (μg/m³) [a]			Receptor Location [b]		Time Period (YYMMDDHH)	Florida AAQS (μg/m³)
	Total	Modeled Sources	Background	Direction (degree)	Distance (m)		
Highest Annual Arithmetic Mean	45.3	13.3	32	134.4	1,750.3	87123124	100
	47.8	15.8	32	271.0	1,219.4	88123124	
	46.4	14.4	32	275.7	1,225.2	89123124	
	51.0	19.0	32	266.3	1,221.8	90123124	
	46.0	14.0	32	261.6	1,232.3	91123124	

Note: YYMMDDHH = Year, Month, Day, Hour Ending

[a] Concentrations are based on highest concentrations predicted using five years of surface and upper air meteorological data for 1987 to 1991 from the National Weather Service station at Palm Beach International Airport.

[b] Locations are relative to the midpoint of the former Palm Beach Power Corp. Boiler Nos. 1 and 2, which is the modeling origin (0,0).

Table 6-9. Maximum Predicted NO_2 Concentrations for All Sources Compared to the PSD Class II Increment - Osceola Farms

Rank/ Averaging Time	Concentration [a] ($\mu g/m^3$) Modeled Sources	Receptor Location[b] Direction (degree)	Distance (m)	Time Period (YYMMDDHH)	PSD Class II Increment ($\mu g/m^3$)
Highest Annual Arithmetic Mean	5.7	134.4	1,750.3	87123124	25
	7.6	271.0	1,219.4	88123124	
	6.2	275.7	1,225.2	89123124	
	10.4	266.3	1,221.8	90123124	
	6.7	261.6	1,232.3	91123124	

Note: YYMMDDHH = Year, Month, Day, Hour Ending

[a] Concentrations are based on highest concentrations predicted using five years of surface and upper air meteorological data for 1987 to 1991 from the National Weather Service station at Palm Beach International Airport.

[b] Locations are relative to the midpoint of the former Palm Beach Power Corp. Boiler Nos. 1 and 2, which is the modeling origin (0,0).

Table 6-10. Summary of Maximum NO_2 Concentrations Predicted for the Project, Compared to the EPA Class I Significant Impact Levels PSD Class I Area of the Everglades National Park

Rank/ Averaging Time	Project Concentration ($\mu g/m^3$) [a]	Receptor UTM Location (km) East	Receptor UTM Location (km) North	Time Period (YYMMDDHH)	EPA Class I Significant Impact Level ($\mu g/m^3$)
Highest Annual	0.0007	550.3	2,848.6	90123124	0.1
	0.0011	547.0	2,848.6	92123124	
	0.0013	534.0	2,848.6	96123124	

Note: UTM = Universal Transverse Mercator
YYMMDDHH = Year, Month, Day, Hour Ending

[a] Based on the CALPUFF model using 1990, 1992, and 1996 surface and upper air meteorological data developed with the CALMET program. UTM coordinates relative to Zone 17.

Figure 6-1. Osceola Farms Property Boundary and Off-Property Receptors Used in the Modeling Analysis

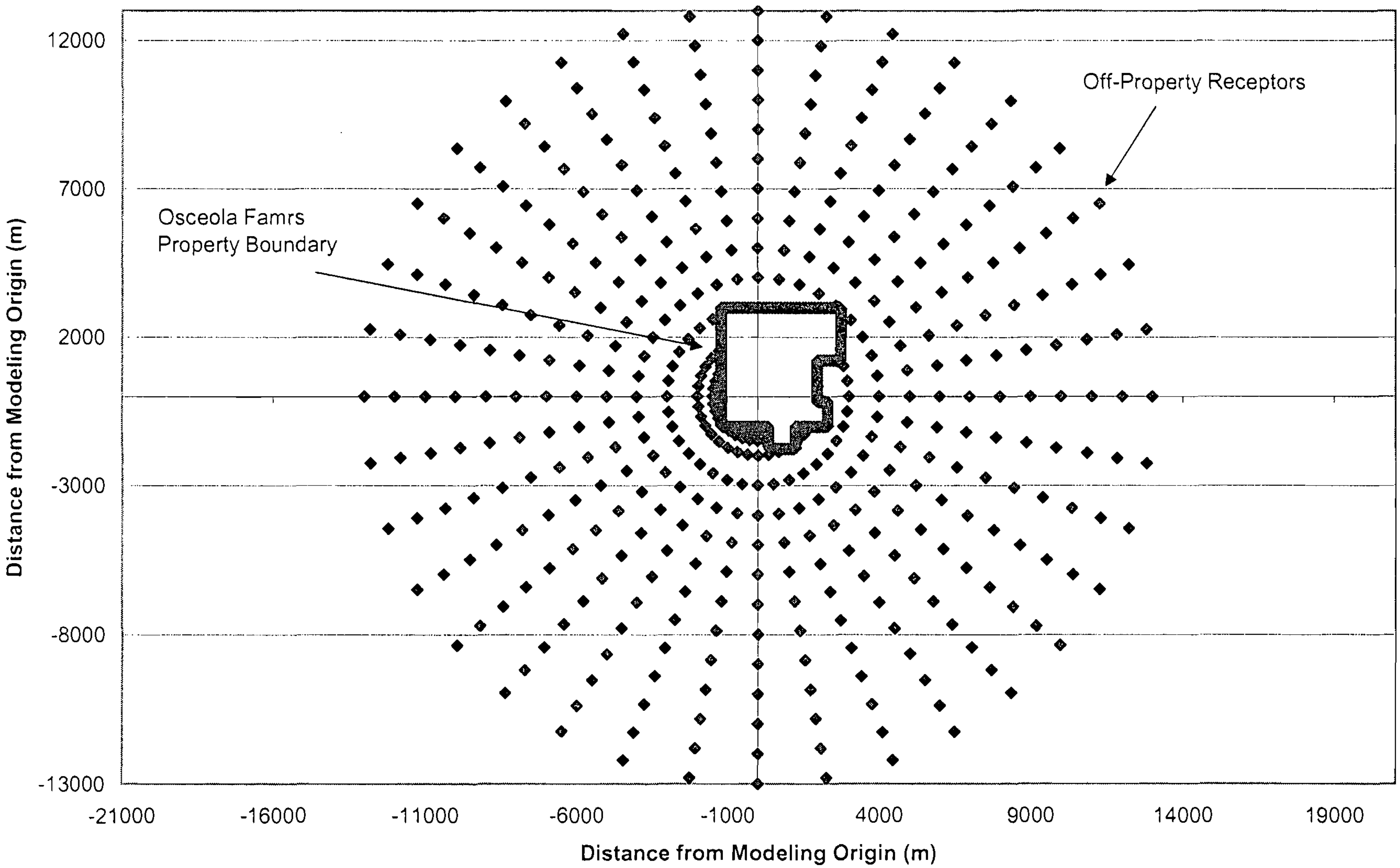
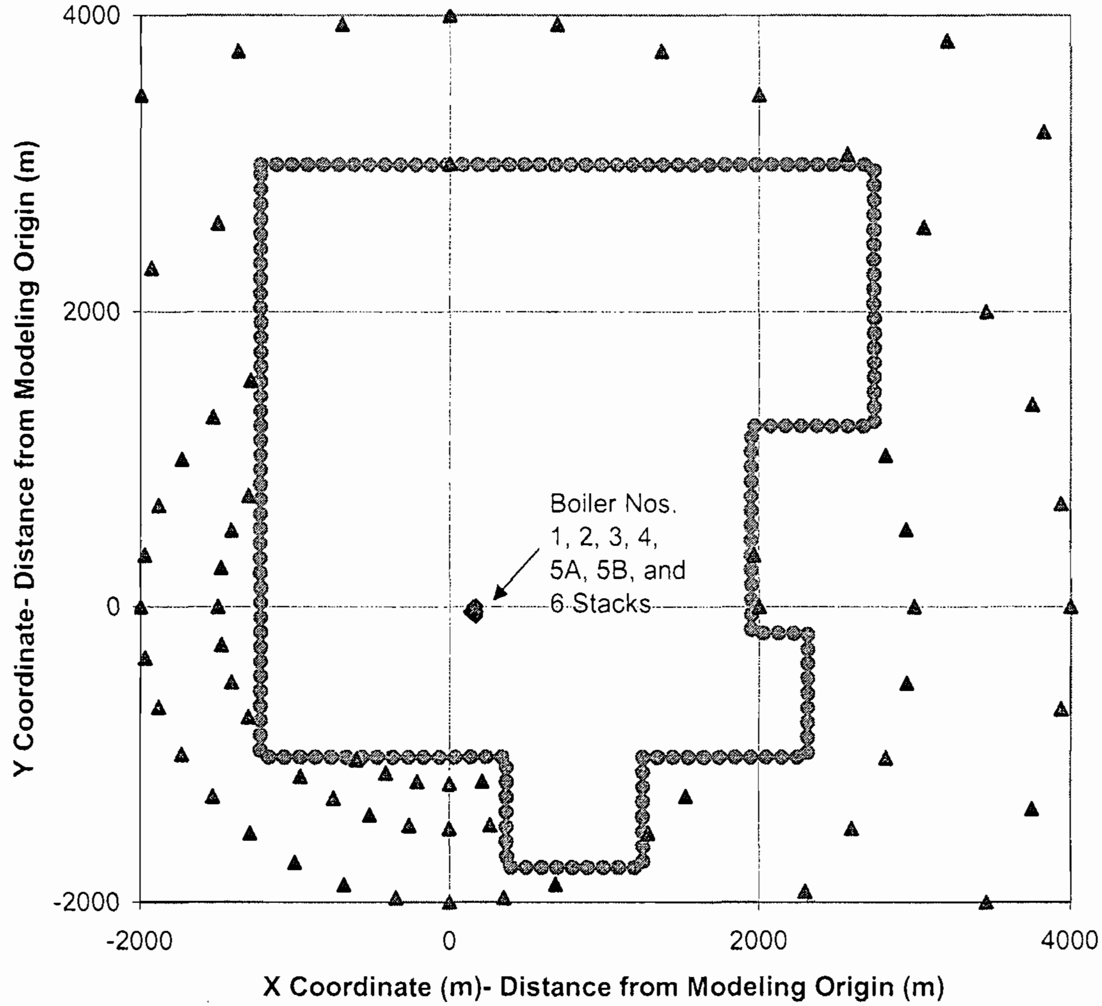


Figure 6-2. Osceola Farms Property Boundary Receptors and Source Locations



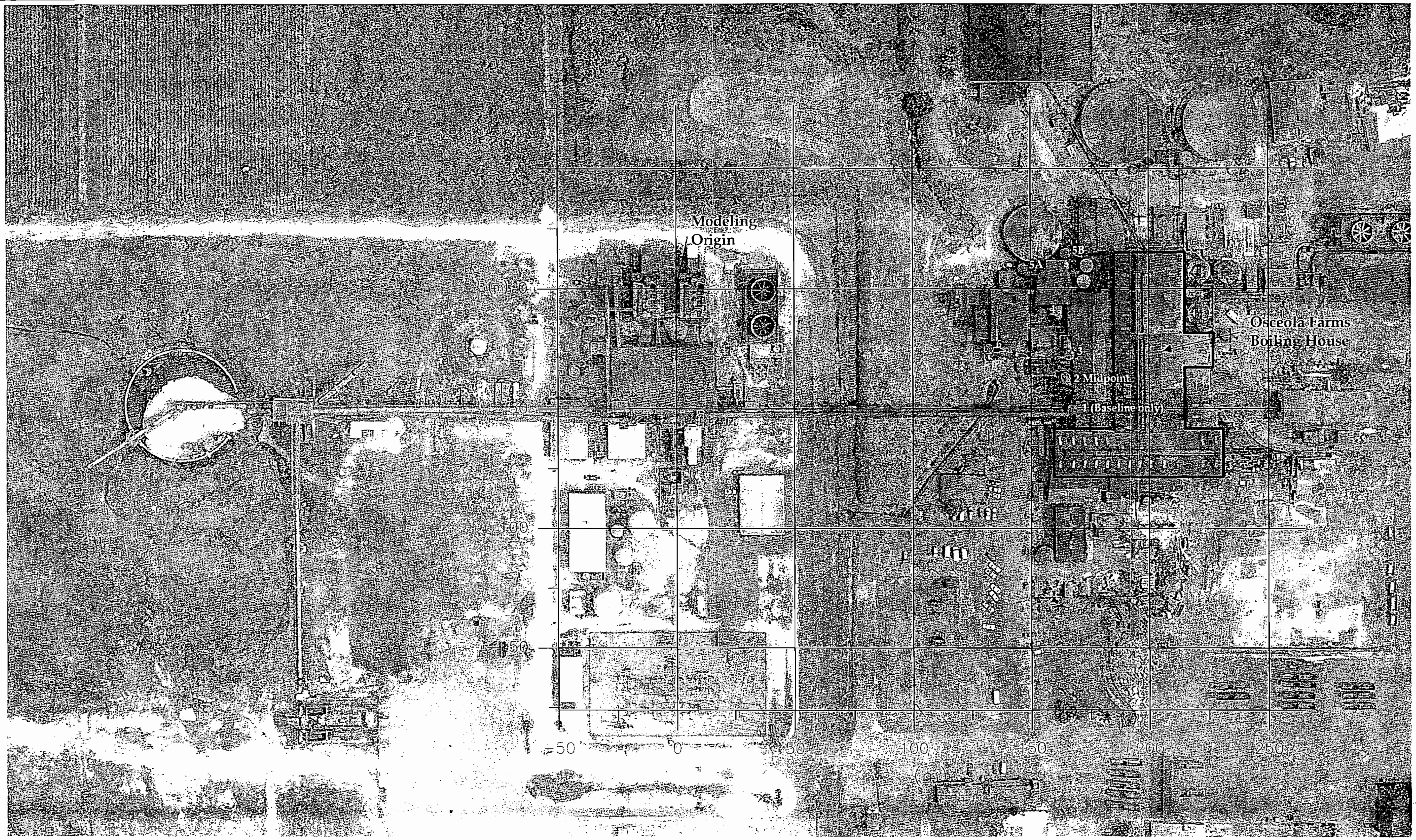


Figure 6-3
Modeling Origin and Source Locations – Osceola Farms

Source: Photogrammetric Technologies, Inc., 2002; Golder, 2003.

Golder Associates

7.0 ADDITIONAL IMPACT ANALYSIS

This section presents the impacts the proposed project will have on vegetation, soils, visibility, and direct growth resulting from the project.

7.1 <u>IMPACTS DUE TO ASSOCIATED DIRECT GROWTH</u>

7.1.1 INTRODUCTION

Rule 62-212.400(3)(h)(5), F.A.C., states that an application must include information relating to the air quality impacts of, and the nature and extent of all general, residential, commercial, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. This growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the proposed changes to Boiler Nos. 4 and 5. This information is consistent with the EPA Guidance related to this requirement in the *Draft New Source Review Workshop Manual* (EPA, 1990).

In general, there has been minimal growth in the Osceola Farms area since 1977. The site is located in Palm Beach County, to the east of Lake Okeechobee. Palm Beach County is on Florida's Atlantic coast, north of Ft. Lauderdale, and is bordered by Broward, Hendry, and Martin Counties. The county has 236 square miles of water. Palm Beach County is the second largest county in Florida, comprising a 1,964-square mile area. The county has 236 square miles of water. Located within the county is Loxahatchee National Wildlife Refuge.

As stated in Section 2.0, Boiler Nos. 4 and 5 are being modified to meet current and projected demands for the Osceola Farms sugar mill. Additional growth, as a direct result of the additional demand provided by the project, is expected to be minimal. Modification of Boiler Nos. 4 and 5 will occur over approximately a 1-year period, requiring an average of approximately 10 workers during that time. It is anticipated that many of these construction personnel will commute to the site.

The modification of Boiler Nos. 4 and 5 will result in no increase in operational workers at the site. The workforce needed to operate Boiler Nos. 4 and 5 will remain the same as the present operation. Therefore, there will be no increase in vehicular traffic in the area due to the project.

No air quality impacts are expected due to associated industrial and commercial growth, given the location of the existing Osceola Farms mill. The existing commercial and industrial infrastructures are adequate to provide any support services that the project might require and would not increase with the operation of the project.

The following discussion presents general trends in residential, commercial, industrial, and other growth that has occurred since August 7, 1977, in Palm Beach County. As such, the information presents information available from a variety of sources (i.e., Florida Statistical Abstract, FDEP, etc.) that characterize Palm Beach County as a whole.

7.1.2 RESIDENTIAL GROWTH

Population and Household Trends

As an indicator of residential growth, the trend in the population and number of household units in Palm Beach County since 1977 are shown in Figure 7-1. The county experienced a 128-percent increase in population for the years 1977 through 2000. During this period, there was an increase in population of about 635,000. Similarly, the number of households in the county increased by about 226,000, or 91 percent, since 1977.

Growth Associated with the Operation of the Project

Because of no additional workers needed to operate the project, residential growth due to the project will not occur.

7.1.3 COMMERCIAL GROWTH

Retail Trade and Wholesale Trade

As an indicator of commercial growth in Palm Beach County, the trends in the number of commercial facilities and employees involved in retail and wholesale trade are presented in Figure 7-2. The retail trade sector comprises establishments engaged in retailing merchandise. The retailing process is the final step in the distribution of merchandise. Retailers are, therefore, organized to sell merchandise in small quantities to the general public. The wholesale trade sector comprises establishments engaged in wholesaling merchandise. This sector includes merchant wholesalers who buy and own the goods they sell; manufacturers' sales branches and offices that sell products manufactured domestically by their own company; and agents and brokers who collect a commission or fee for arranging the sale of merchandise owned by others.

Since 1977, retail trade has increased by 3,163 establishments and 92,023 employees or 114 and 157 percent, respectively. For the same period, wholesale trade has increased by 2,052 establishments and 18,327 employees, or 356 and 389 percent, respectively.

Labor Force

The trend in the labor force in Palm Beach County since 1977 is shown in Figure 7-3. The greatest number of persons employed in Palm Beach County has been in the agriculture, services, and government sectors. Between 1977 and 2000, approximately 318,644 persons were added to the available work force, for an increase of 181 percent.

Tourism

Another indicator of commercial growth in Palm Beach County is the tourism industry. As an indicator of tourism growth in the county, the trend in the number of hotels and motels and the number of units at the hotels and motels are presented in Figure 7-4.

This industry comprises establishments primarily engaged in marketing and promoting communities and facilities to businesses and leisure travelers through a range of activities, such as assisting organizations in locating meeting and convention sites; providing travel information on area attractions, lodging accommodations, restaurants; providing maps; and organizing group tours of local historical, recreational, and cultural attractions.

Between 1978 and 2000, there was a decrease in the number of hotels and motels in the county; however, there was a significant increase of 39 percent in the number of units at those facilities.

Transportation

As an indicator of transportation growth, the trend in the number of vehicle miles traveled (VMT) by motor vehicles on major roadways in Palm Beach County is presented in Figure 7-5.

The county's main arteries are Interstate 95 and the Florida Turnpike, which run north-south through the eastern section of the county. Other major highways in the county are U.S. Highways 441, 98, and 27. State and county highways in the county include S.R. A1A and 80 and County Roads 827 and 880.

Between 1977 and 2001, there was an increase of more than 10,000,000 VMT, or 69 percent, on major roadways in the county.

Growth Associated with the Operation of the Project

The existing commercial and transportation infrastructure should be adequate to provide any support services that might be required during construction and operation of the project. The workforce needed to operate the proposed project represents a small fraction of the labor force present in the immediate and surrounding areas.

7.1.4 INDUSTRIAL GROWTH

Manufacturing and Agricultural Industries

As an indicator of industrial growth, the trend in the number of employees in the manufacturing industry in Palm Beach County since 1977 is shown in Figure 7-6. As shown, the manufacturing industry experienced a significant increase of 49 percent from 1977 through 2000.

As another indicator of industrial growth, the trend in the number of employees in the agricultural industry, including sugar, in Palm Beach County since 1977 is also shown in Figure 7-6. As shown, the agricultural industry experienced an increase in employment of 513 percent from 1977 through 2000.

Utilities

Existing power plants in Palm Beach County include the following:

- Florida Power & Light's Riviera Plant, and
- Lake Worth Utilities.

Together, these power plants have an electrical generating capacity of over 1,000 megawatts (MW).

As an indicator of electrical utility growth, the electrical generation capacity in Palm Beach County since 1977 is shown in Figure 7-7.

Growth Associated with the Operation of the Project

Since the PSD baseline date of August 7, 1977, there have been only a few major facilities built within a 35-km radius of the plant site. The nearest such source is the FPL Martin Plant. There are a limited number of facilities located throughout the 35-km radius area surrounding the Osceola Farms Mill. Based on the locations of nearby air emission sources, as shown in Figure 7-8, there has not been a concentration of industrial and commercial growth in the vicinity of the Osceola Farms Mill.

7.1.5 AIR QUALITY DISCUSSION

Air Emissions and Spatial Distribution of Major Facilities

The spatial distribution of major air pollutant facilities in Palm Beach County is shown in Figure 7-8. Based on actual emissions reported for 1999 (latest year of available data) by EPA on its AIRSdata website, total emissions from stationary sources in the county are as follows:

- SO_2: 32,198 TPY
- PM_{10}: 2,112 TPY
- NO_x: 11,155 TPY
- CO: 6,515 TPY
- VOC: 2,557 TPY

Air Emissions from Mobile Sources

The trends in the air emissions of CO, VOC, and NO_x from mobile sources in Palm Beach County are presented in Figure 7-9. Between 1977 and 2002, there were significant decreases in these emissions. The decrease in CO, VOC, NO_x emissions were about 1,200, 60, and 29 tons per day (TPD), respectively, which represent decreases from 1977 emissions of 68, 68, and 27 percent, respectively.

Air Monitoring Data

Since 1977, Palm Beach County has been classified as attainment or maintenance for all criteria pollutants. Air quality monitoring data have been collected in Palm Beach County, primarily in the eastern portion of the county. For this evaluation, the air quality monitoring data collected at the monitoring station nearest to the Osceola Farms Mill were used to assess air quality trends since 1977. Air quality monitoring data were based on the following monitoring stations:

- PM_{10} concentrations - Belle Glade;
- NO_2 concentrations - West Palm Beach and Palm Beach;
- CO concentrations - West Palm Beach and Palm Beach; and
- O_3 concentrations - West Palm Beach and Royal Palm Beach.

Data collected from these stations are considered to be generally representative of air quality in Palm Beach County. Because these monitoring stations are generally located in more industrialized areas than the Osceola Farms Mill area, the reported concentrations are likely to be somewhat higher than that experienced at the site.

These data indicate that the maximum air quality concentrations currently measured in the region comply with and are well below the applicable AAQS. These monitoring stations are located in areas where the highest concentrations of a measured pollutant are expected due to the combined effect of emissions from stationary and mobile sources, as well as the effects of meteorology. Therefore, the ambient concentrations in areas not monitored should have pollutant concentrations less than the monitored concentrations from these sites.

In addition, since 1988, PM in the form of PM_{10} has been collected at the air monitoring stations due to the promulgation of the PM_{10} AAQS. Prior to 1989, the AAQS for PM was in the form of total suspended particulates (TSP) concentrations, and this form was measured at the stations.

PM_{10}/TSP Concentrations

The trends in the 24-hr and annual average PM_{10} and TSP concentrations since 1977 are presented in Figures 7-10 and 7-11, respectively. TSP concentrations are presented through 1988 since the AAQS was based on TSP concentrations through that year. In 1988, the TSP AAQS was revoked and the PM standard was revised to PM_{10}.

As shown in these figures, measured TSP concentrations were generally below the TSP AAQS. Since 1988 when PM_{10} concentrations have been measured, the PM_{10} concentrations have been and continue to be below the AAQS.

NO_2 Concentrations

The trends in the annual average NO_2 concentrations measured at the nearest monitors to the Osceola Farms Mill are presented in Figure 7-12. As shown in this figure, measured NO_2 concentrations have been well below the AAQS.

CO Concentrations

The trends in the 1-hr and 8-hr average CO concentrations since 1977 are presented in Figures 7-13 and 7-14, respectively. As shown in these figures, measured CO concentrations have been well below the AAQS.

Ozone Concentrations

The trends in the 1-hr average O_3 concentrations since 1977 are presented in Figure 7-15. The trends in the 8-hr average O_3 concentrations since 1995 are presented in Figure 7-16. As shown in these figures, even in the more urbanized areas of Palm Beach County, the measured O_3 concentrations have been well below the 1-hr average AAQS and the new 8-hr average AAQS.

Air Quality Associated with the Operation of the Project

The air quality data measured in the region of the Osceola Farms Mill indicate that the maximum air quality concentrations are well below and comply with the AAQS. Also, based on the trends presented of these maximum concentrations, the air quality has generally improved in the region since the baseline date of August 7, 1977. Because the maximum concentrations for modification of Boiler Nos. 4 and 5 are predicted to be below the significant impact levels and the total air quality concentrations are predicted to be below the AAQS, air quality concentrations in the region are expected to remain below and comply with the AAQS when the modifications to Boiler Nos. 4 and 5 become operational.

7.2 IMPACTS ON SOILS, VEGETATION, WILDLIFE, AND VISIBILITY IN THE VICINITY OF THE SITE

7.2.1 IMPACTS ON VEGETATION AND SOILS

The primary vegetation, as well as agricultural crop, in the vicinity of Osceola Farms Mill is sugar cane. The site is surrounded by sugar cane fields for a large distance in all directions. Some rice fields, vegetable farming, nurseries, and sod farms are also located in the general area.

Soils in the area are primarily histosols, which are peat soils with high amounts of organic matter. The surrounding area is part of the Everglades Agricultural Area, which is noted for its "muck", i.e., rich, black soil that is very fertile.

As described in the air quality impact analysis (Section 6.0), the maximum predicted NO_2 concentrations in the vicinity of Osceola Farms Mill due to the proposed project are predicted to be below the AAQS. Since the AAQS are designed to protect the public welfare, including effects on soils and vegetation, no detrimental effects on soils or vegetation should occur in this area due to the proposed project.

7.2.2 IMPACTS ON WILDLIFE

Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. Generally, there are three ways pollutants may affect wildlife: through inhalation, through exposure with skin, and through ingestion (Newman, 1980). Ingestion is the most common means and can occur through eating or drinking of high concentrations of pollutants. Bioaccumulation is the process of animals collecting and accumulating pollutant levels in their bodies over time. Other animals that prey on these animals would then be ingesting concentrated pollutant levels.

It is unlikely that the project's emissions will cause injury or death to wildlife based on a review of the limited literature on air pollutant effects on wildlife. The project's impacts are predicted to be very low and dispersed over a large area. Coupled with the mobility of wildlife, the potential for exposure of wildlife to the project's impacts under weather conditions that lead to high concentrations is extremely unlikely.

7.2.3 IMPACTS ON VISIBILITY

The boilers currently have wet scrubbers. These wet scrubbers will be modified to reduce permitted emissions. As a result, visible emissions should not be adversely affected. The nearest residence is several miles away. Therefore, no adverse impacts upon visibility in the vicinity of Osceola Farms Mill are expected.

7.3 IMPACTS TO PSD CLASS I AREA

7.3.1 IDENTIFICATION OF AQRV AND METHODOLOGY

The potential impacts of PM_{10} and VOC emissions due to the proposed project on soils, vegetation, wildlife, and visibility in the ENP Class I area are addressed in this section. This section focuses on the ecological effects of the project on AQRV, as defined under PSD regulations, in the ENP. The

ENP is the closest Class I area to the project, and is located approximately 120 km south of the Osceola mill.

The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

> 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 ENP and bioindicators of air pollution (e.g., lichens) are also evaluated.

The maximum predicted NO_2 concentrations due to the increase in emissions resulting from the proposed project are presented in Table 7-1. As shown, the predicted increases in impacts are very low.

7.3.2 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 ENP 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 calcium carbonate ($CaCO_3$)].

The relatively low sensitivity of the soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants projected for the ENP from the facility emissions precludes any significant impact on soils.

7.3.3 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, which is a very conservative approach.

The concentrations of the pollutants, duration of exposure, and frequency of exposures influence the response of vegetation 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, 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

NO_2 can 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 exposure (1, 4, 8 hours) 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 ranging from 2,000 to 4,000 $\mu g/m^3$ for 213 to 1,900 hr 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-hr averaging times) and long-term (annual averaging time) modeled concentrations, the possibility of plant damage in the ENP can be examined for both acute and chronic exposure situations, respectively. The 1-, 3-, and 8-hr estimated maximum increase in NO_2 concentrations due to the proposed project in the ENP area are 0.29, 0.22, and 0.18 $\mu g/m^3$, respectively (see Table 7-1). These concentrations are less than 0.008 percent of the levels that could potentially injure 5 percent of the plant foliage. For a chronic exposure, the maximum increase in annual NO_2 concentrations of 0.001 $\mu g/m^3$ in the ENP is less than 0.001 percent of the levels that caused minimal yield loss and chlorosis in plant tissue.

Although it has been shown that simultaneous exposure to SO_2 and NO_2 results in synergistic plant injury (Ashenden and Williams, 1980), the magnitude of this response is generally only 3 to 4 times greater than either gas alone and usually occurs at unnaturally high levels of each gas. Therefore, the concentrations within the ENP are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

VOC Emissions and Impacts to Ozone

It is difficult to predict what effect the proposed increase in emissions of VOC will have on ambient O_3 concentrations on a regional scale. VOC and NO_x emissions are precursors to the formation of O_3. O_3 is not directly emitted from fuel combustion, but is formed down-wind from emission sources when VOC and NO_x emissions react in the presence of sunlight. Natural (without man-made sources) ambient concentrations of O_3 are normally in the range of 20 to 39 $\mu g/m^3$ (0.01 to 0.02 ppm) (Heath, 1975).

The nearest monitors to the Osceola Farms Mill that measure O_3 concentrations are located in Palm County (see Table 4-2). These stations measure concentrations according to EPA procedures. Based on the O_3 monitoring concentrations measured over the last several years, the region is in attainment of the existing 1-hour O_3 AAQS as well as the new 8-hour O_3 AAQS.

O_3 can cause various damage to broad-leaved plants including: tissue collapse, interveinal necrosis and markings on the upper surface leaves know as stippling (pigmented yellow, light tan, red brown, dark brown, red, or purple), flecking (silver or bleached straw white), mottling, chlorosis or bronzing, and bleaching. O_3 can also stunt plant growth and bud formation. On certain plants such as citrus, grape, and tobacco, it is common for leaves to wither and drop early.

Total VOC emissions in Palm Beach County are approximately 54,600 TPY for stationary and mobile sources [projected for 2005 from the Air Quality Maintenance Plan (2005-2015); Dade, Broward, and Palm Beach Counties, FDEP, 2002]. The VOC emissions increase due to the proposed Osceola project (244 TPY) represents less than a 0.5-percent increase in regional VOC emissions. Therefore, the effects of O_3, as a result of VOC emissions from the project, are expected to be insignificant.

Summary

In summary, the phytotoxic effects on the ENP from the proposed project emissions are expected to be minimal. The increase in ambient impacts on the ENP are predicted to be very low. 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.

7.3.4 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 AAQS. 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 7-2.

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the NAAQS. 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 NO_x, which are reported to cause physiological changes, are shown in Table 7-2. These values are up to orders of magnitude larger than the maximum increase in concentrations predicted for the Class I area due to the proposed project. Therefore, no effects are predicted to occur as a result of the proposed project (Newman, 1975).

Research with primates shows that O_3 penetrates deeper into non-ciliated peripheral pathways and can cause lesions in the respiratory bronchioles and alveolar ducts as concentrations increase from 0.2 to 0.8 ppm (Paterson, 1997). These bronchioles are the most common site for severe damage. In rats, the Type I cells in the proximal alveoli (where gas exchange occurs) were the primary site of action at concentrations between 0.5 and 0.9 ppm (Paterson, 1997). Work with rats and rabbits suggest that the mucus layer that lines the large airways does not protect completely against the effects of O_3, and desquamated cells were found from acute exposures at 0.25, 0.5, and 1.0 ppm. In animal research, O_3 has been found to increase the susceptibility to bacterial pneumonia (Paterson, 1997). During the last decade, there has also been growing concern with the possibility that repeated or long-term exposure to elevated O_3 concentrations may be causing or contributing to irreversible chronic lung injury.

The project's contribution to ground level O_3 is expected to be very low and dispersed over a large area. Coupled with the historical ambient data, mobility of wildlife, the potential for exposure of wildlife to the facility's impacts that lead to high concentration is extremely unlikely.

No effects on wildlife AQRVs from NO_x or VOC emissions are expected. These results are considered indications of the risk of other air pollutant emissions predicted from the facility.

7.4 IMPACTS ON VISIBILITY

7.4.1 INTRODUCTION

The CAA Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Sources of air pollution can cause visible plumes if emissions of PM_{10} and NO_x are sufficiently large. A plume will be visible if its constituents scatter or absorb sufficient light so that the plume is brighter or darker than its viewing background (e.g., the sky or a terrain feature, such as a mountain). PSD Class I areas, such as national parks and wilderness areas, are afforded special visibility protection designed to prevent plume visual impacts to observers within a Class I area.

Visibility is an AQRV for the Everglades NP. Visibility can take the form of plume blight for nearby areas or regional haze for long distances (e.g., distances beyond 50 km). Because the ENP is more than 50 km from the Osceola Farms, the change in visibility is analyzed as regional haze.

Currently, there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and the FLM of Class I areas who are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in two documents:

- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report; and
- *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report,* USFS, NPS, USFWS (December, 2000), referred to as the FLAG document.

The methods and assumptions recommended in these documents were used to assess visibility impairment due to the project.

7.4.2 ANALYSIS METHODOLOGY

Based on the FLAG document, current regional haze guidelines characterize a change in visibility by the 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. An index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

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

The purpose of the visibility analysis is to calculate the extinction at each receptor for each day (24-hour period) of the year due to the proposed project. The criteria to determine if the project's impacts are potentially significant are based on a change in extinction of 5 percent or greater for any day of the year.

Processing of visibility impairment for this study was performed with the CALPUFF model (see Appendix F) and the CALPUFF post-processing program CALPOST. The analysis was conducted in accordance with the most recent guidance from the FLAG report (December 2000). The CALPUFF postprocessor model CALPOST is used to calculate the combined visibility effects from the different pollutants that are emitted from the project. Daily background extinction coefficients are calculated on an hour-by-hour basis using hourly relative humidity data from CALMET and hygroscopic and non-hygroscopic extinction components specified in the FLAG document. For the Class I area evaluated, the hygroscopic and non-hygroscopic components are 0.9 and 8.5 per mega meter (Mm^{-1}), respectively. CALPOST then predicts the percent extinction change for each day of the year.

The increase in PM and NO_x emissions associated with the proposed project are shown in short-term.

7.4.3 RESULTS

The results of the refined regional haze analysis are presented in Table 7-3. The results indicate that the proposed project's maximum predicted impact on visibility at the ENP is 3.01 percent. This value is below the FLM's screening criteria of 5-percent change. Therefore, the proposed modification to Boilers Nos. 4 and 5 is not expected to have an adverse impact on the existing regional haze in the ENP.

7.5 NITROGEN DEPOSITION

7.5.1 GENERAL METHODS

As part of the AQRV analyses, total nitrogen (N) deposition rates were predicted at the ENP Class I area. The deposition analysis thresholds are based on the annual averaging period. The total deposition is estimated in units of kilogram per hectare per year (kg/ha/yr) of nitrogen. The CALPUFF model is used to predict wet and dry deposition fluxes of various oxides of these elements.

For N deposition, the species include:

- Particulate ammonium nitrate (from species NO_3), wet and dry deposition;
- Nitric acid (species HNO_3), wet and dry deposition;
- NO_x, dry deposition; and
- Ammonium sulfate (species SO_4), wet and dry deposition.

The CALPUFF model produces results in units of $\mu g/m^2/s$. The modeled deposition rates are then converted to N deposition in kg/ha respectively, by using a multiplier equal to the ratio of the molecular weights of the substances (IWAQM Phase II report, Section 3.3).

The deposition analysis threshold (DAT) for nitrogen deposition of 0.01 kg/ha/yr was provided by the U.S. Fish and Wildlife Service [USFWS (January 2002)]. A DAT is the additional amount of N deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant. This value is then compared to the DAT.

7.5.2 RESULTS

The maximum N deposition predicted for the proposed project in the PSD Class I area of the ENP is summarized in Table 7-4. The maximum N deposition rate for the project is predicted to be 0.0004 kg/ha/yr. This deposition rate is below the DAT for N of 0.01 kg/ha/yr. As a result, the project's emissions are not expected to have a significant adverse effect on N deposition at the Class I area.

Table 7-1. Summary of Maximum NO_2 Concentrations Predicted for the Project for the AQRV Analysis, PSD Class I Area of the Everglades National Park

Averaging Time	Project Concentration ($\mu g/m^3$) [a]	Receptor UTM Location (km)		Time Period (YYMMDDHH)
		East	North	
1-Hour	0.295	543.0	2,848.6	90122503
	0.246	550.3	2,848.6	92120903
	0.239	528.0	2,848.6	96120401
3-Hour	0.190	536.0	2,848.6	90111903
	0.220	547.0	2,848.6	92120906
	0.182	527.0	2,848.6	96120403
8-Hour	0.170	536.0	2,848.6	90111908
	0.184	548.0	2,848.6	92120908
	0.146	529.0	2,848.6	96120408
24-Hour	0.059	537.0	2,848.6	90111924
	0.063	548.0	2,848.6	92120924
	0.052	530.0	2,848.6	96120424
Annual	0.0007	550.3	2,848.6	90123124
	0.0011	547.0	2,848.6	92123124
	0.0013	534.0	2,848.6	96123124

Note: UTM = Universal Transverse Mercator
YYMMDDHH = Year, Month, Day, Hour Ending

[a] Based on the CALPUFF model using 1990, 1992, and 1996 surface and upper air meteorological data developed with the CALMET program. UTM coordinates relative to Zone 17.

Table 7-2. 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
Sulfur Dioxide[a]	Respiratory stress in guinea pigs	427 to 854	1 hour
	Respiratory stress in rats	267	7 hours/day; 5 day/week for 10 weeks
	Decreased abundance in deer mice	13 to 157	continually for 5 months
Nitrogen Dioxide[b,c]	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates[a]	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: [a] Newman and Schreiber, 1988.
[b] Gardner and Graham, 1976.
[c] Trzeciak *et al.*, 1977.

Table 7-3. Maximum 24-hour Average Visibility Impairment Predicted for the Project at the PSD Class I Area of the Everglades National Park

Rank	Visibility Impairment (%) [a]	Receptor UTM Location (km) East	Receptor UTM Location (km) North	Time Period (YYMMDDHH)	Number of Visibility Impairment Occurrences > 5/10 % Criteria
Highest	1.64	540	2,839.0	90122624	0/0
Highest	3.01	548.0	2,848.0	92121024	0/0
Highest	2.69	515.0	2,848.6	96121524	0/0

Note: UTM = Universal Transverse Mercator
YYMMDDHH = Year, Month, Day, Hour Ending

[a] Based on the CALPUFF model using 1990, 1992, and 1996 surface and upper air meteorological data developed with the CALMET program. UTM coordinates relative to Zone 17.
Maximum relative humidity set to 95%.

Table 7-4. Maximum Annual Sulfur and Nitrogen Deposition Predicted for the Project at the PSD Class I Area of the Everglades National Park

Species	Total Deposition (Wet & Dry)		Receptor UTM Location (km)		Time Period	Deposition Analysis Threshold [b]
	($g/m^2/s$)	(kg/ha/yr)[a]	East	North	(YYMMDDHH)	(kg/ha/yr)
Nitrogen (N) Deposition	8.52E-13	0.0003	459.0	2,863.2	90123124	0.01
	1.13E-12	0.0004	544.0	2,848.6	92123124	
	9.97E-13	0.0003	550.3	2,848.6	96123124	

Note: UTM = Universal Transverse Mercator
YYMMDDHH = Year, Month, Day, Hour Ending

[a] Conversion factor is used to convert $g/m^2/s$ to kg/hectare (ha)/yr with the following units:

$$
\begin{aligned}
g/m^2/s \times\ & 0.001\ kg/g \\
\times\ & 10{,}000\ m^2/hectare \\
\times\ & 3{,}600\ sec/hr \\
\times\ & 8{,}760\ hr/yr = kg/ha/yr \\
\text{or}\ & \\
g/m^2/s \times\ & 3.154E{+}08 = kg/ha/yr
\end{aligned}
$$

[b] Deposition analysis thresholds (DAT) for nitrogen and sulfur deposition provided by the U.S. Fish and Wildlife Service, January 2002. A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant.

Figure 7-1. Population and Household Unit Trends in Palm Beach County

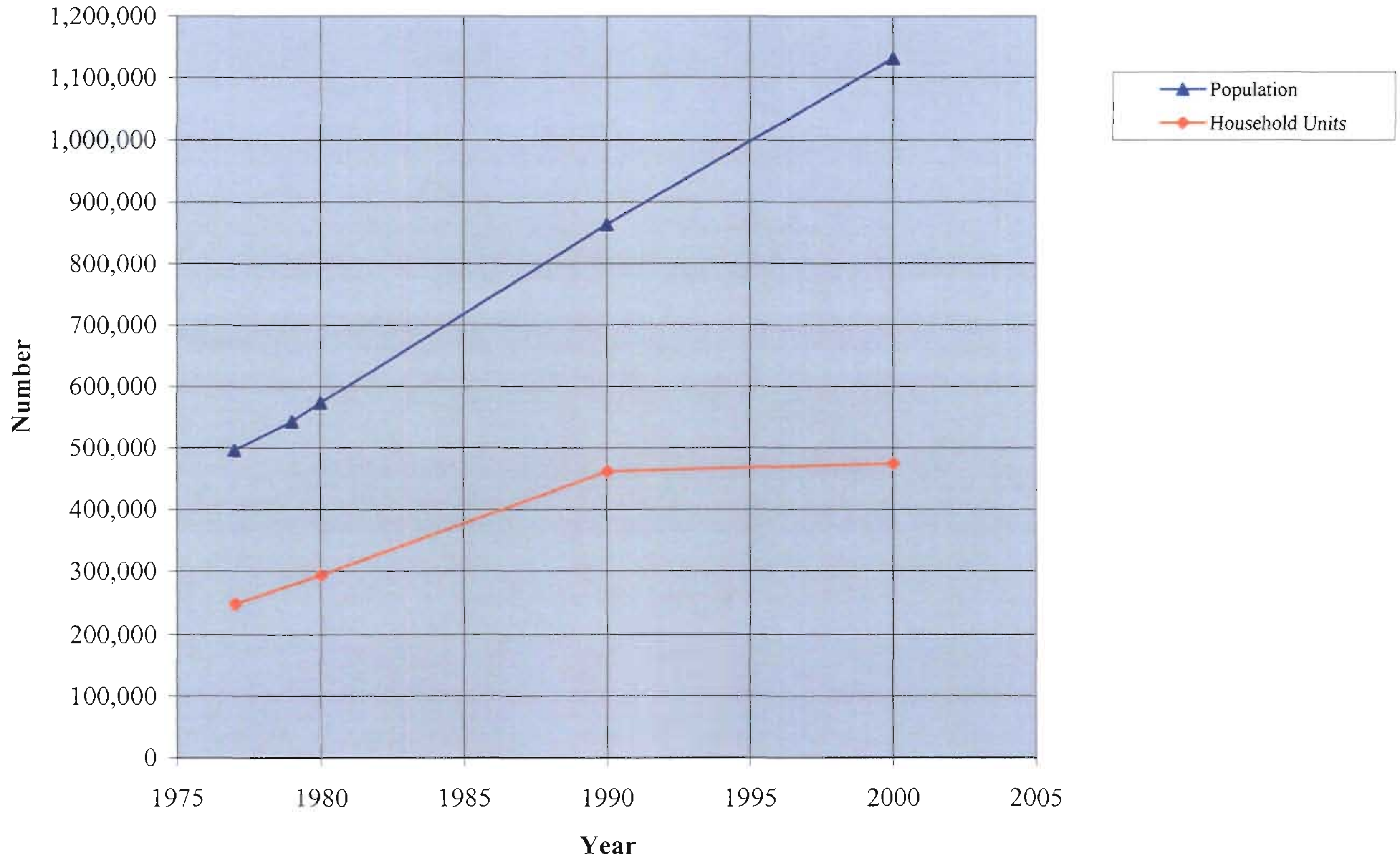


Figure 7-2. Retail and Wholesale Trade Trends in Palm Beach County

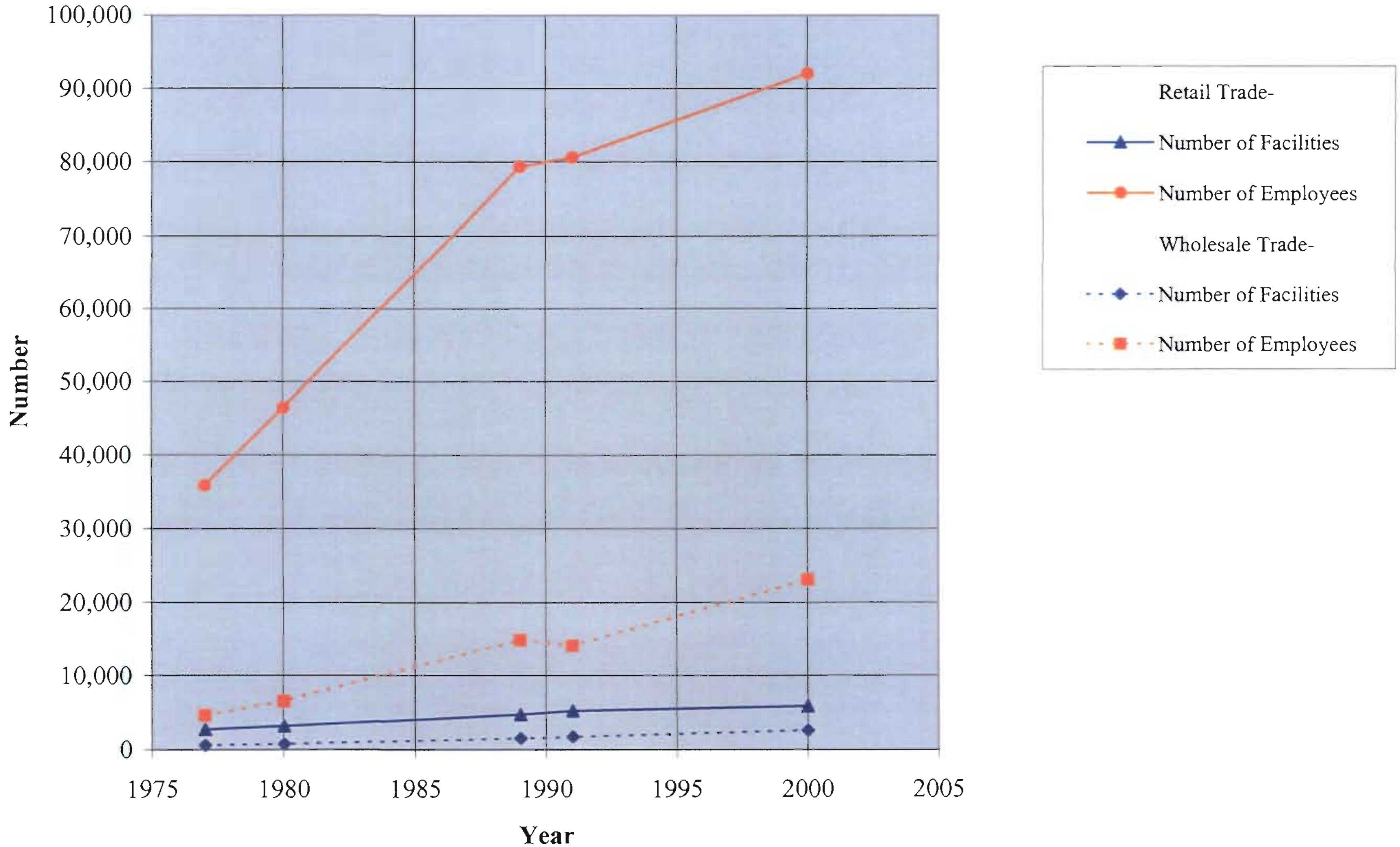


Figure 7-3. Labor Force Trend in Palm Beach County

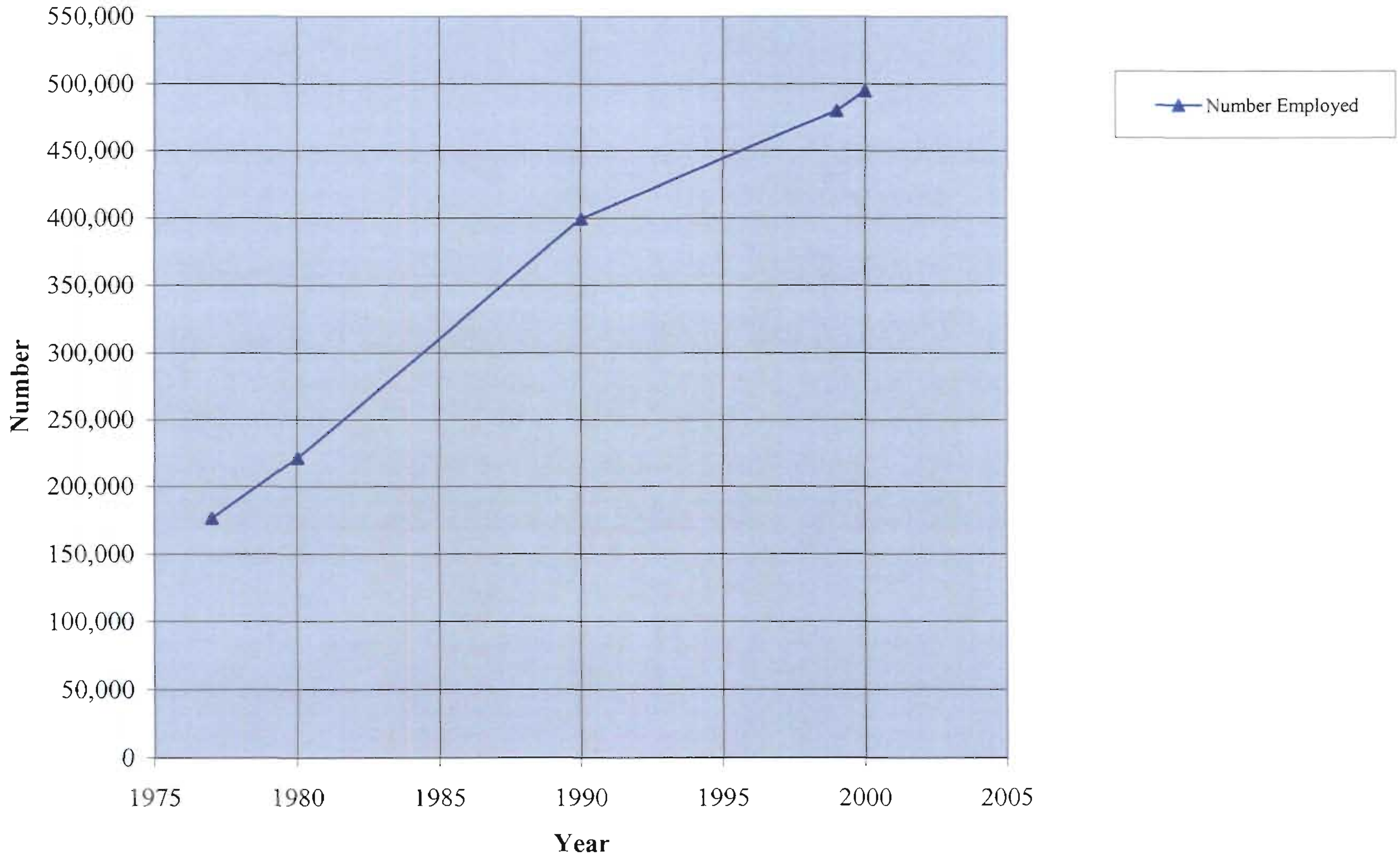


Figure 7-4. Hotel and Motel Trend in Palm Beach County

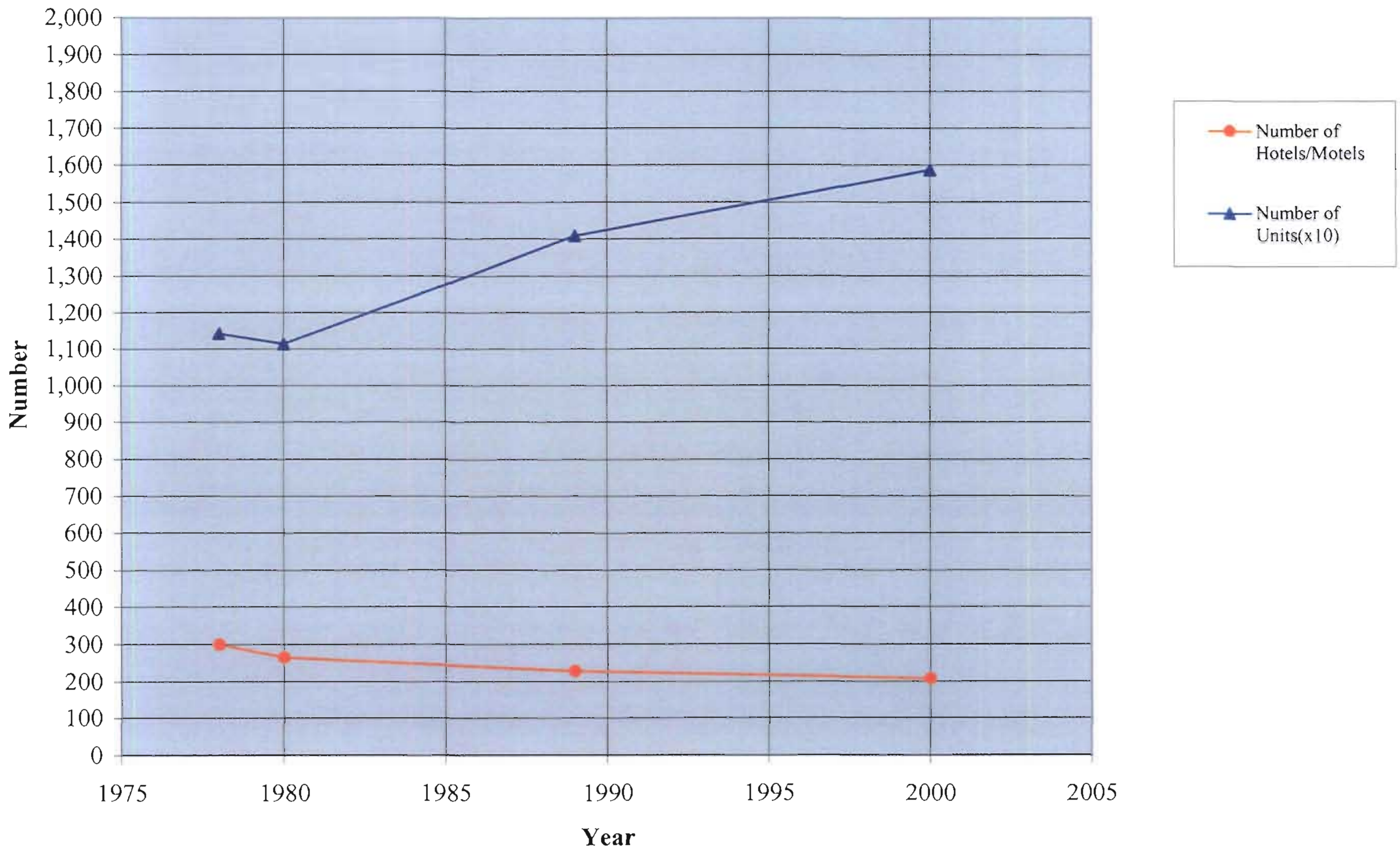


Figure 7-5. Vehicle Miles Traveled (VMT) Estimates for Motor Vehicles for Palm Beach County

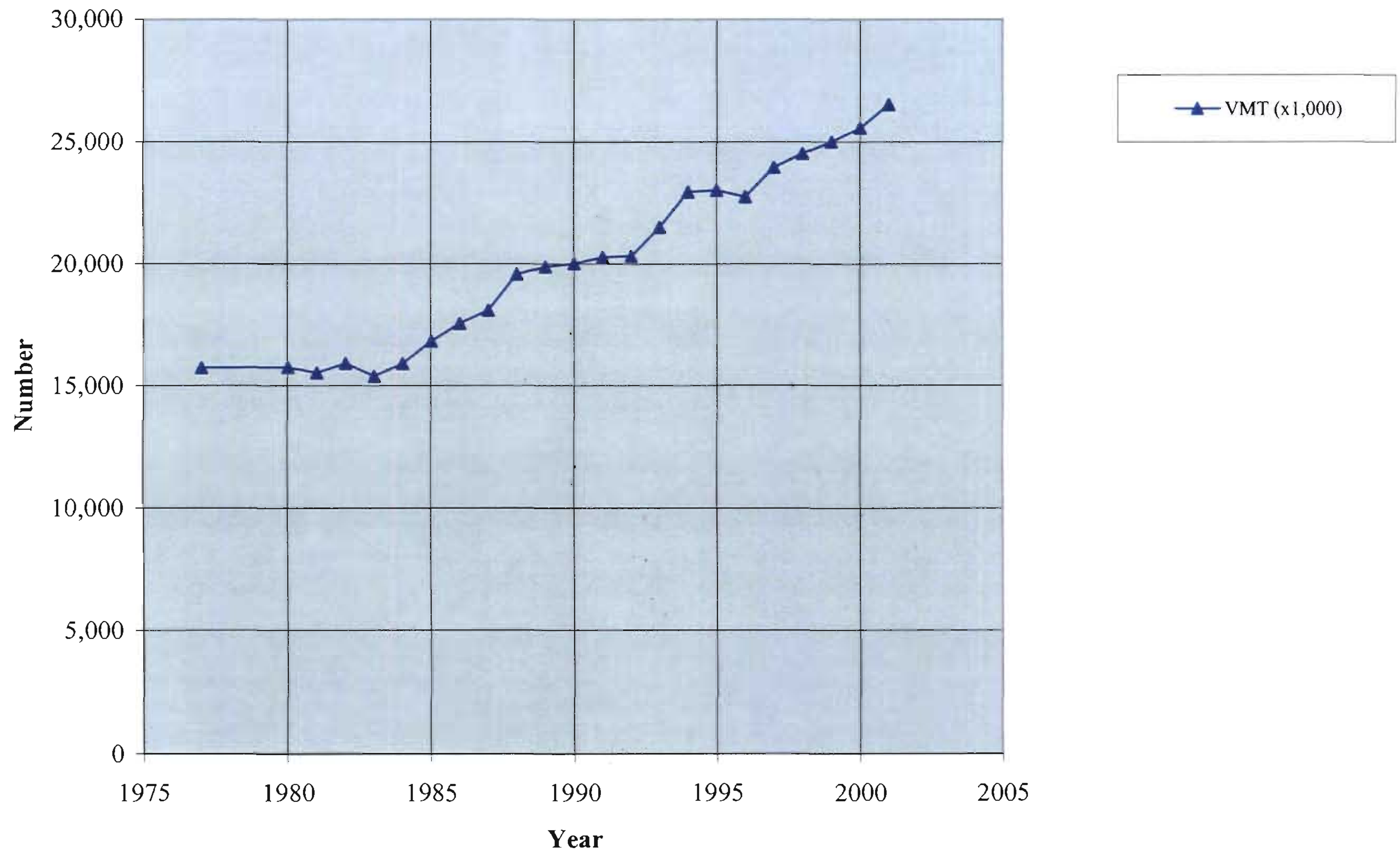


Figure 7-6. Manufacturing, and Agriculture Trends in Palm Beach County

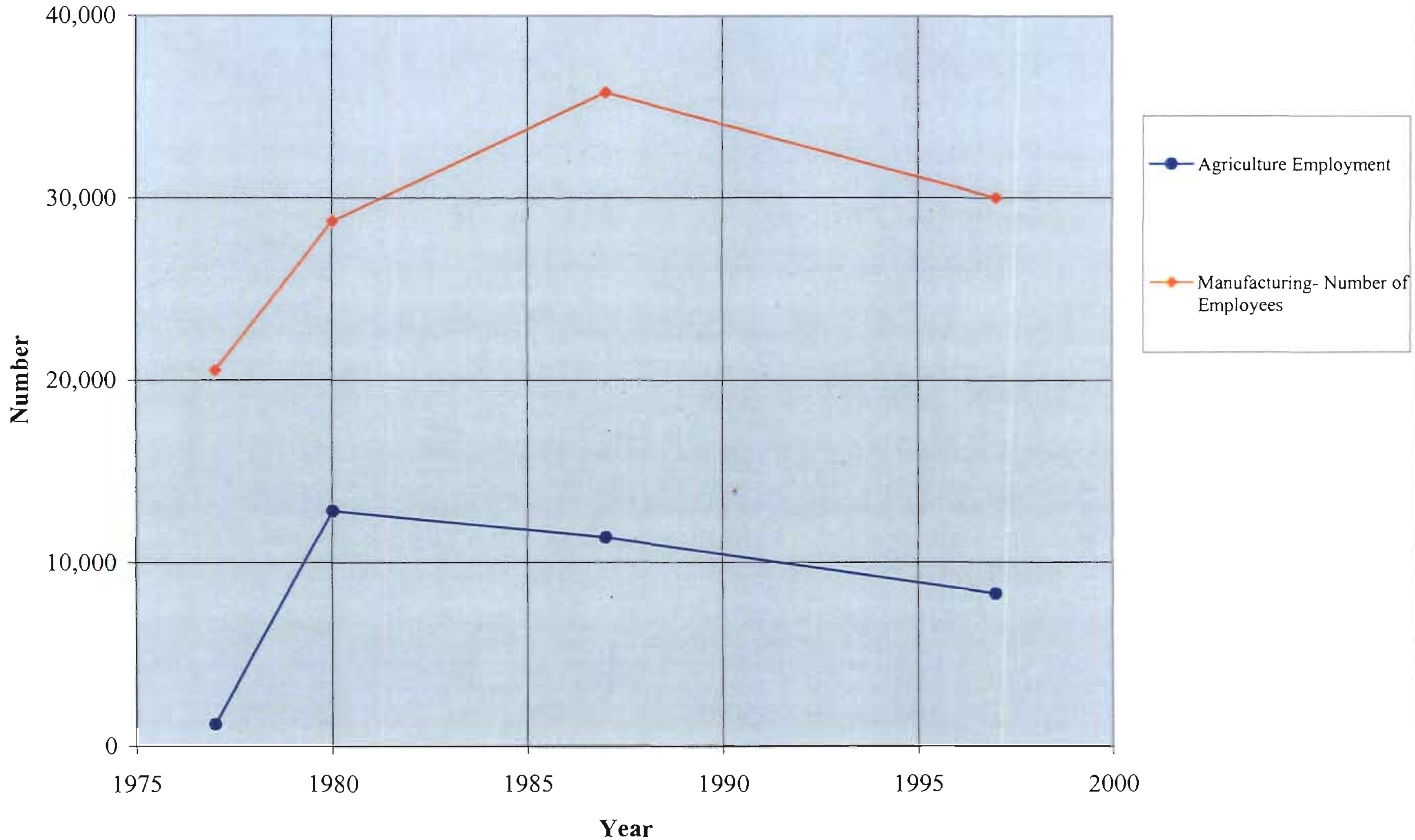
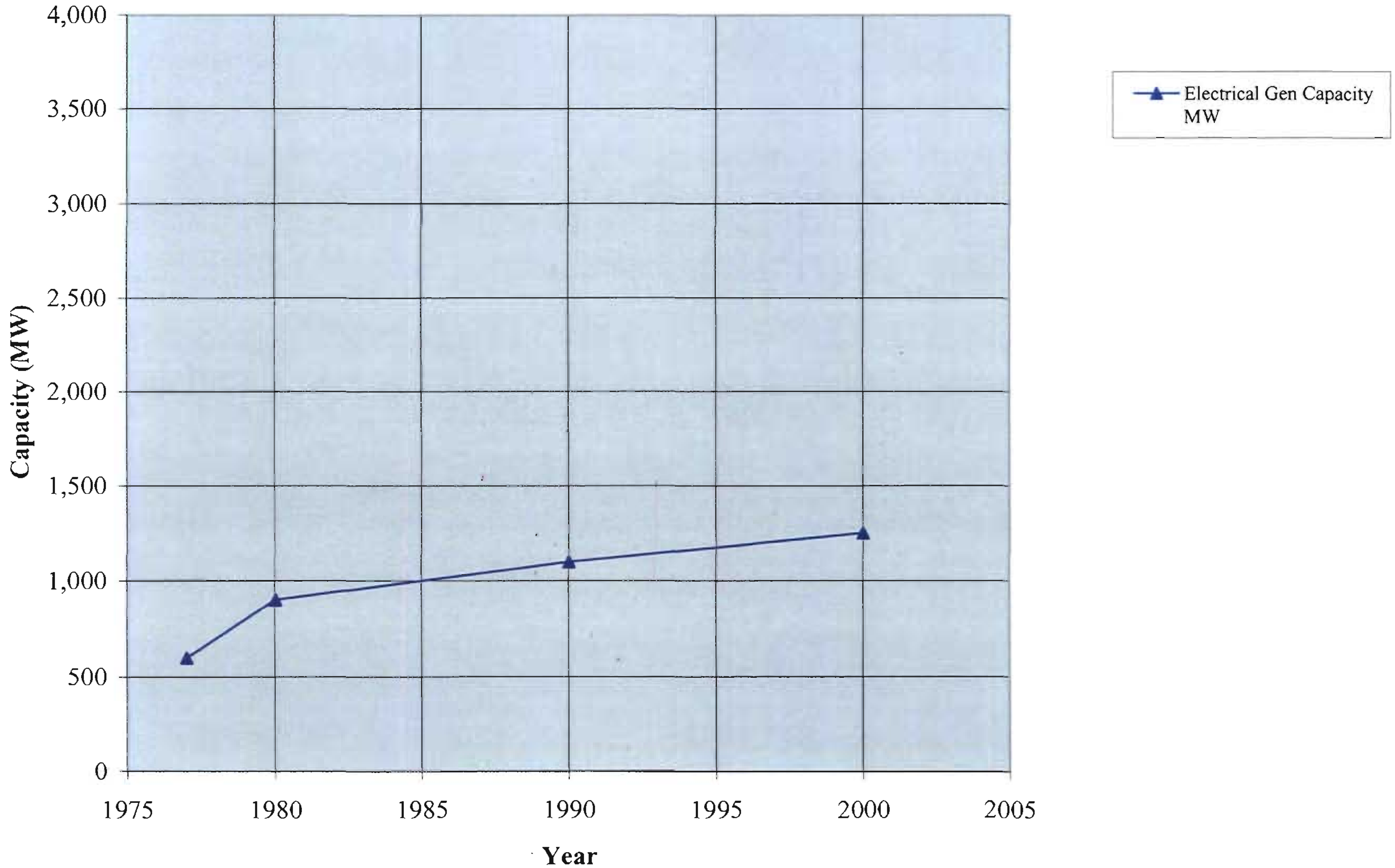


Figure 7-7. Electrical Power Generation Capacity in Palm Beach County



★ **Oceola Farms**

• **Emission Source**

1 - FLORIDA POWER & LIGHT CO., MARTIN
2 - CAULKINS INDIANTOWN CITRUS CO.
3 - BAY STATE MILLING CO.
4 - INDIANTOWN COGENERATION, L.P.
5 - OUTBOARD MARINE CORPORATION
6 - ATLANTIC SUGAR ASSOCIATION
7 - UNITED TECHNOLOGIES CORPORATION
8 - SUGAR CANE GROWERS CO-OP
9 - US SUGAR CORP
10 - FLORIDA DEPARTMENT OF CORRECTIONS
11 - J E WILSON & SON
12 - KIRCHMAN OIL CORP
13 - HOWELL OIL CO., INC.
14 - SUGAR SUPPLY, INC.
15 - SIKORSKY AIRCRAFT CORPORATION
16 - NANA'S PETROLEUM, INC.
17 - PALM BEACH AGGREGATES, INC.

N W E S

10 0 10 Kilometers

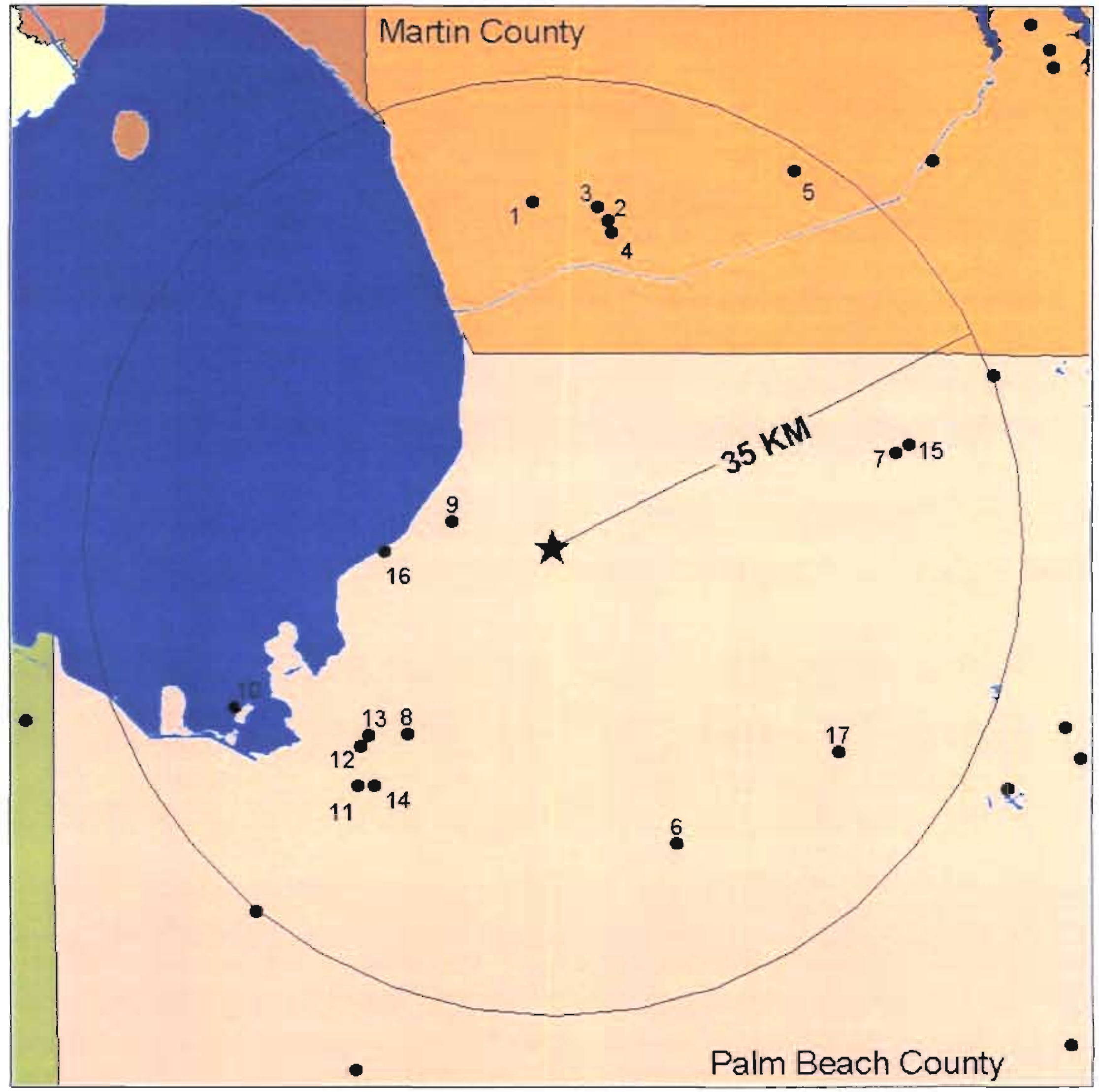


Figure 7-8
Nearby Emission Sources

Source: ESRI, 2002; Golder, 2003.

Golder Associates

Figure 7-9. Mobile Source Emissions (Tons per Day) of CO, VOC, and NO_x in Palm Beach County

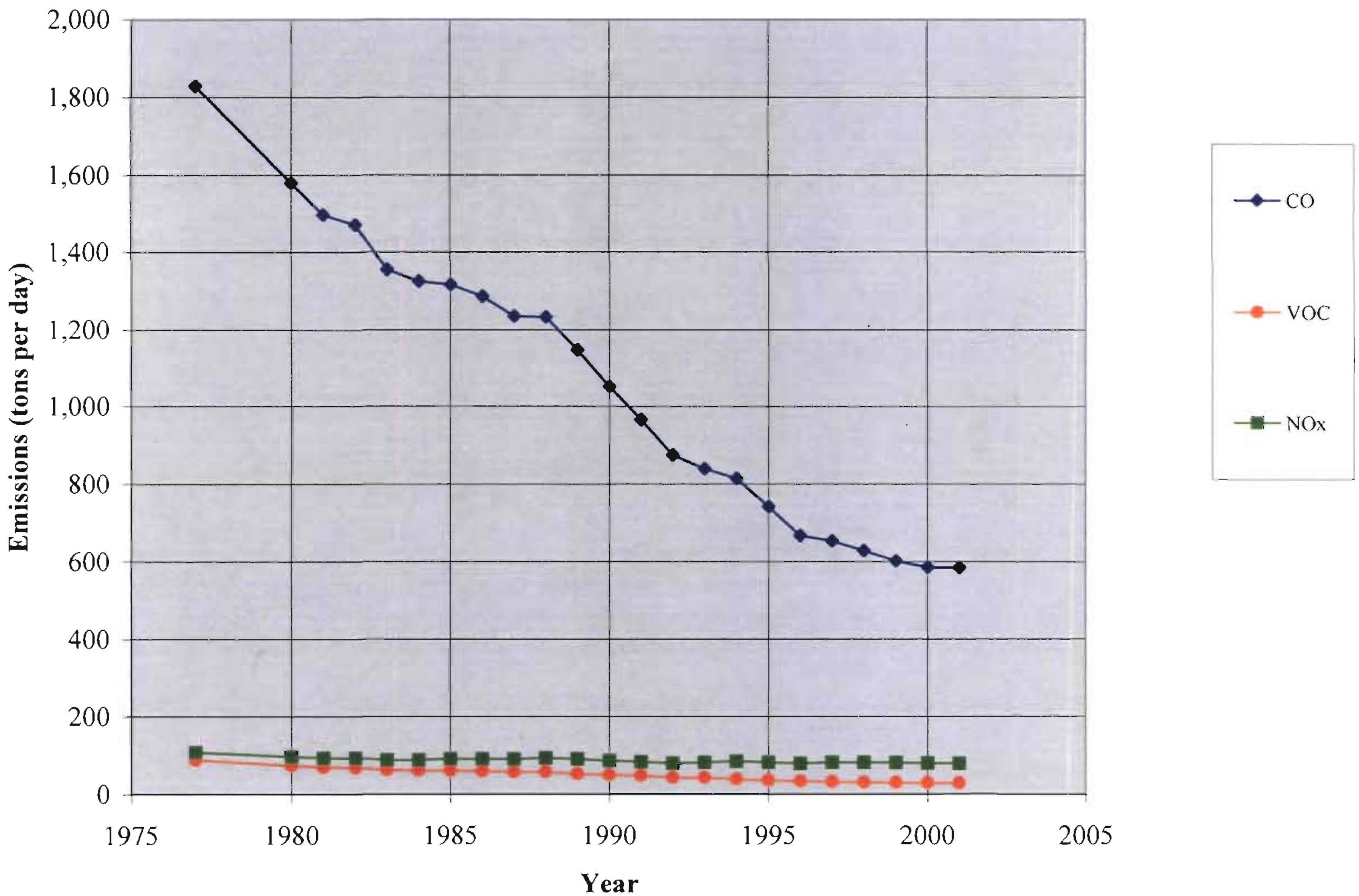


Figure 7-10. Measured 24-Hour Average PM10 and TSP Concentrations (2nd Highest Values) in Belle Glade, Palm Beach County

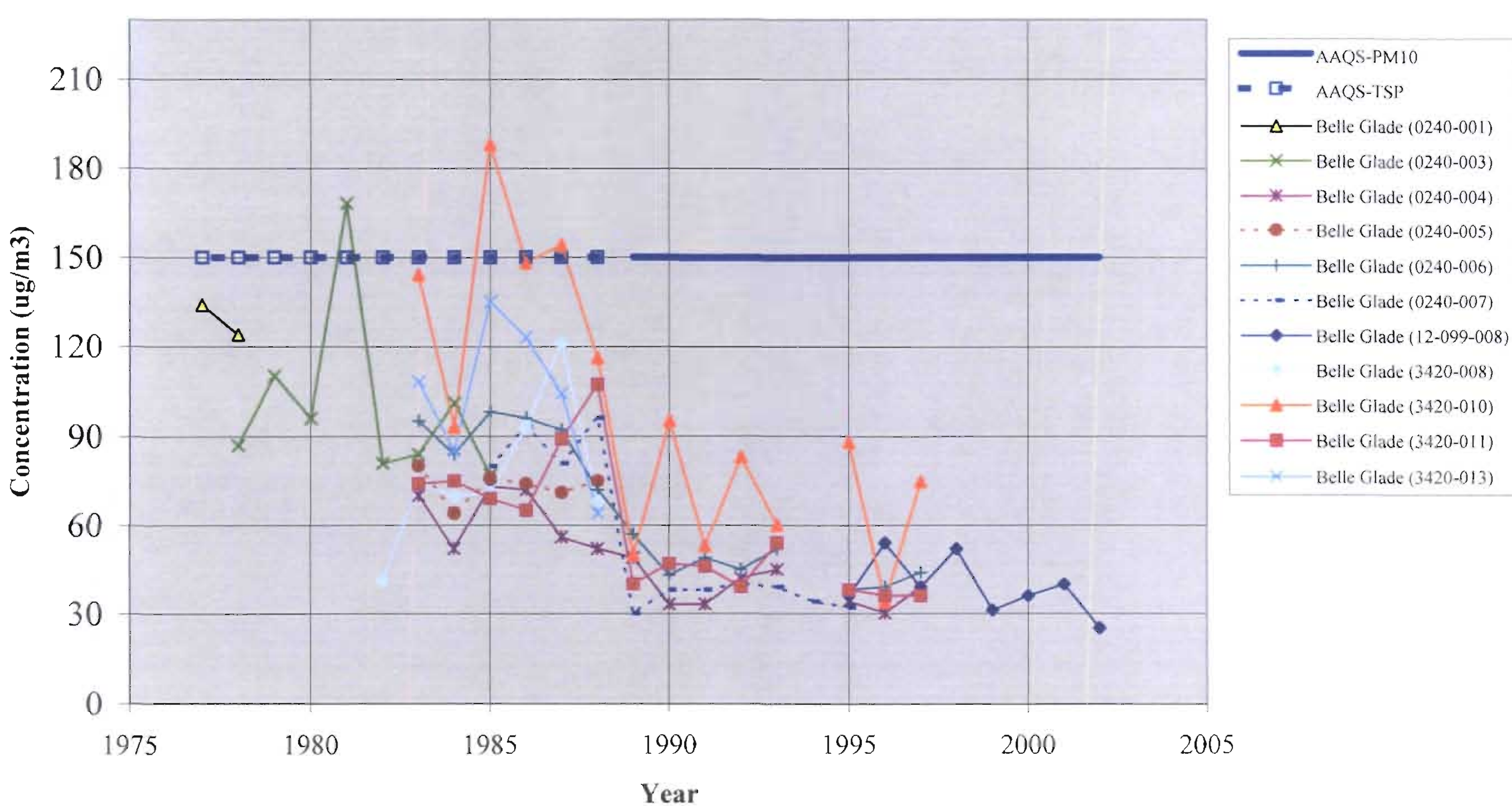


Figure 7-11. Measured Annual Average PM10 and TSP Concentrations (2nd Highest Values) in Belle Glade, Palm Beach County

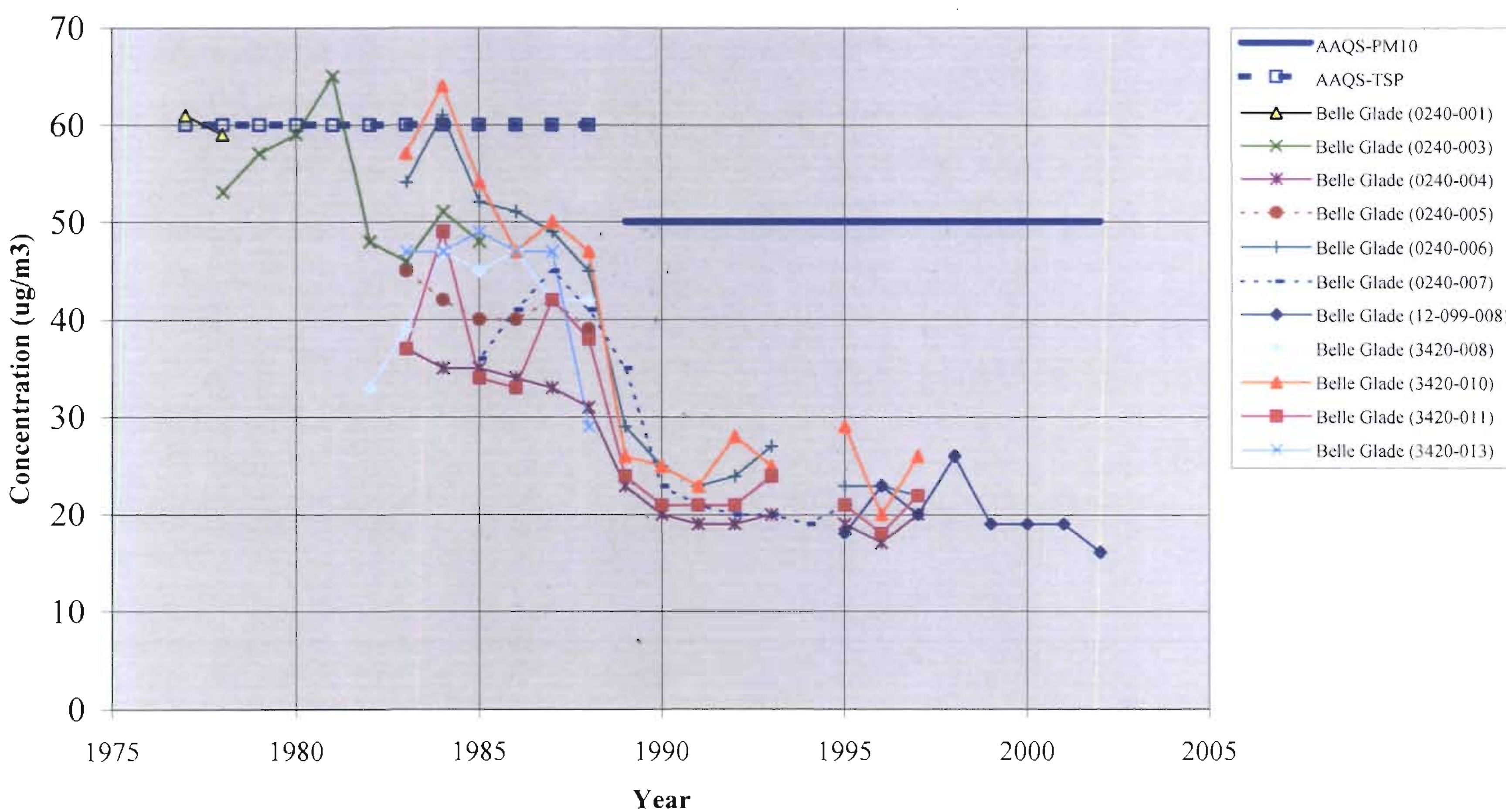


Figure 7-12. Measured Annual Average Nitrogen Dioxide Concentrations in Palm Beach County

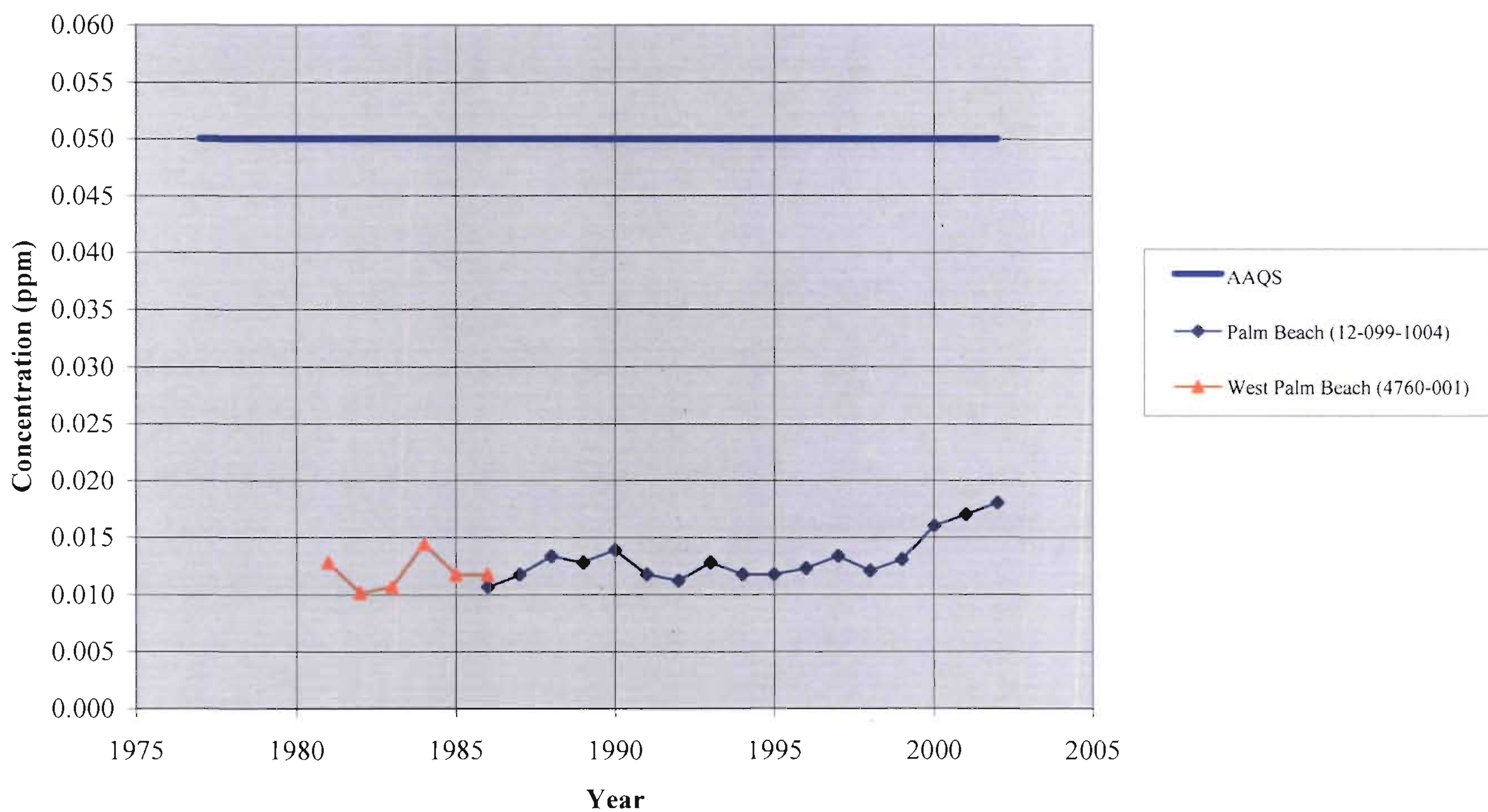


Figure 7-13. Measured 1-Hour Average Carbon Monoxide Concentrations (2nd Highest Values) in Palm Beach County

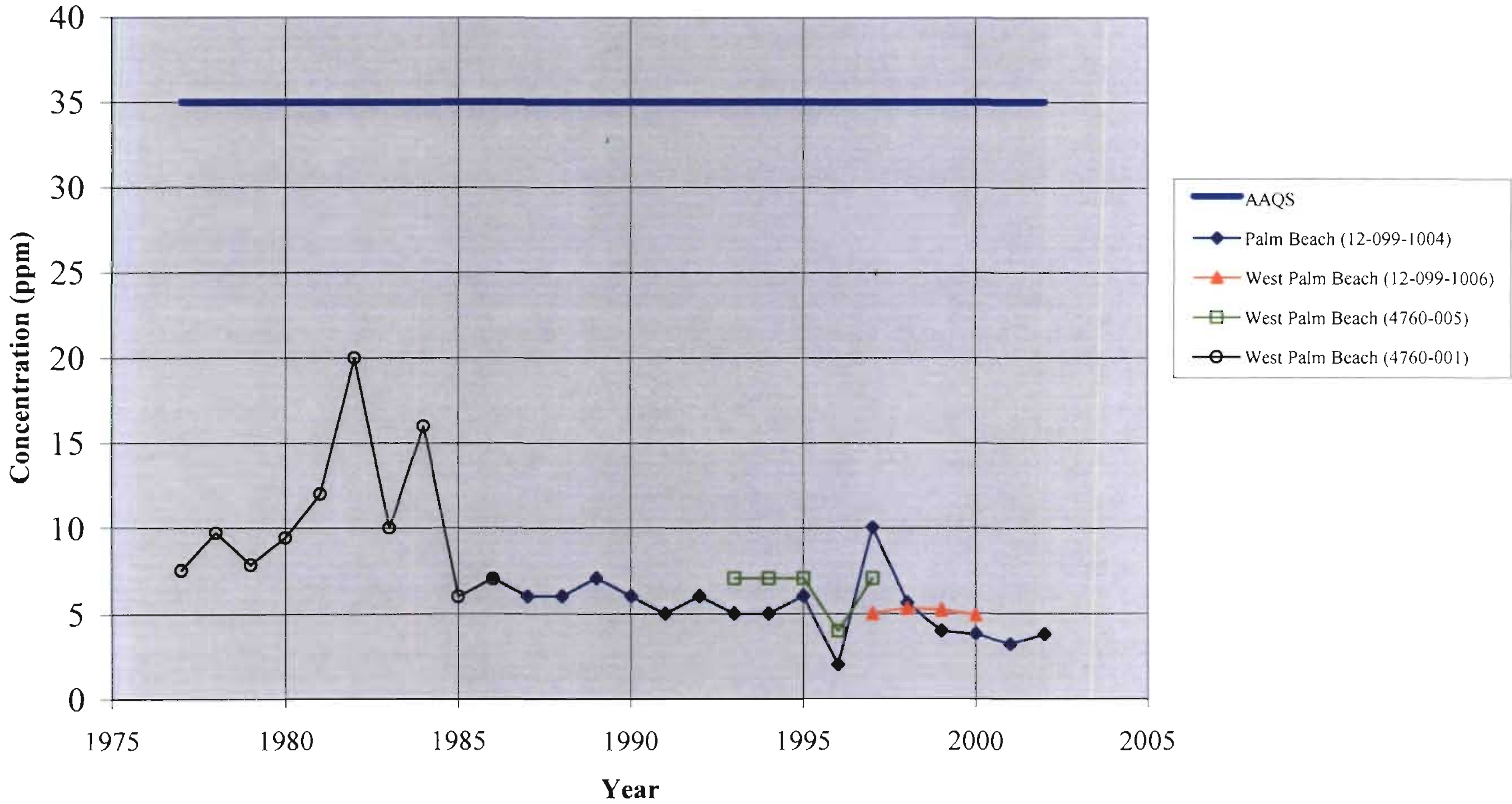


Figure 7-14. Measured 8-Hour Average Carbon Monoxide Concentrations (2nd Highest Values) in Palm Beach County

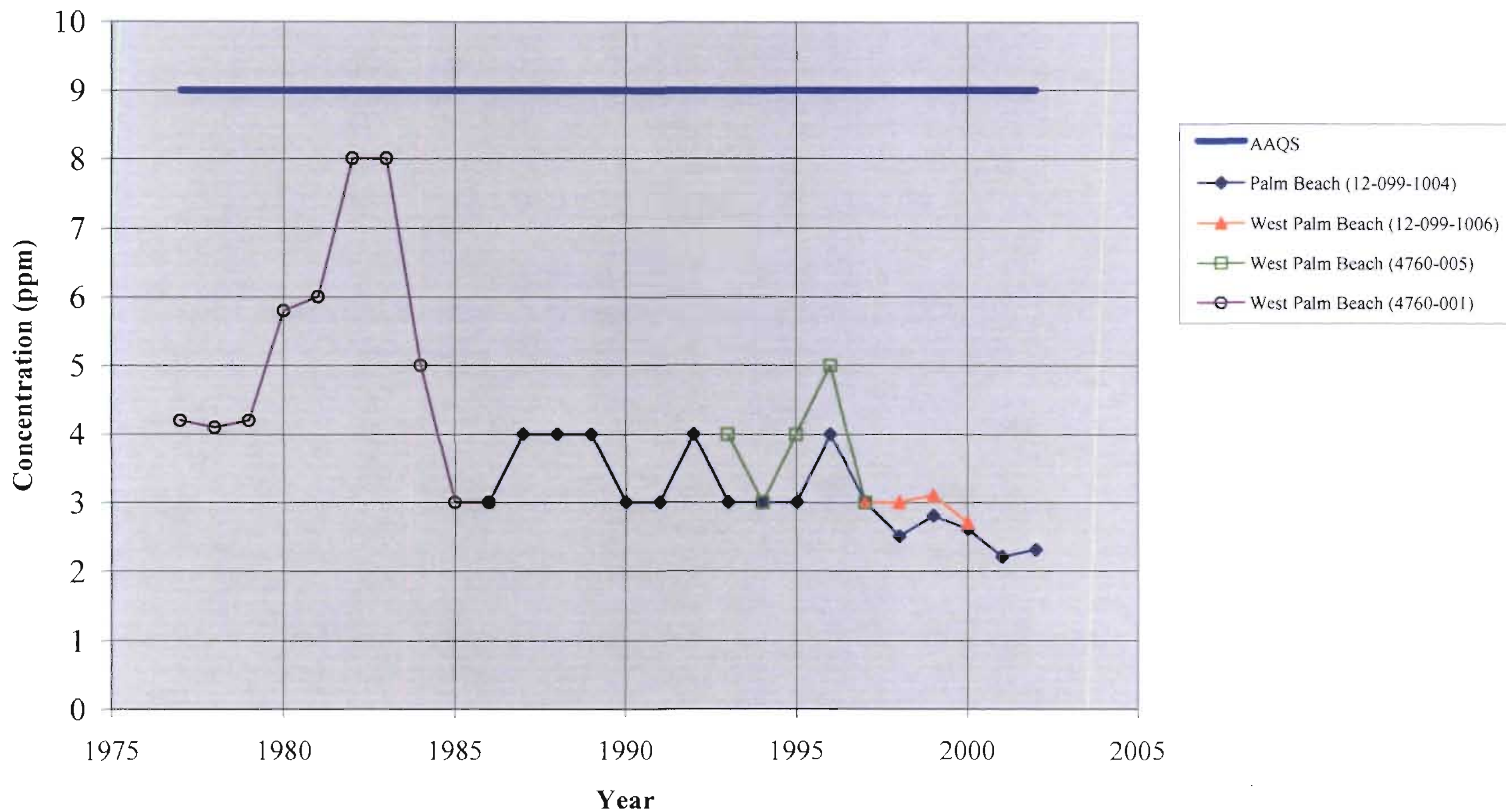


Figure 7-15. Measured 1-Hour Average Ozone Concentrations (2nd Highest Values) in Palm Beach County

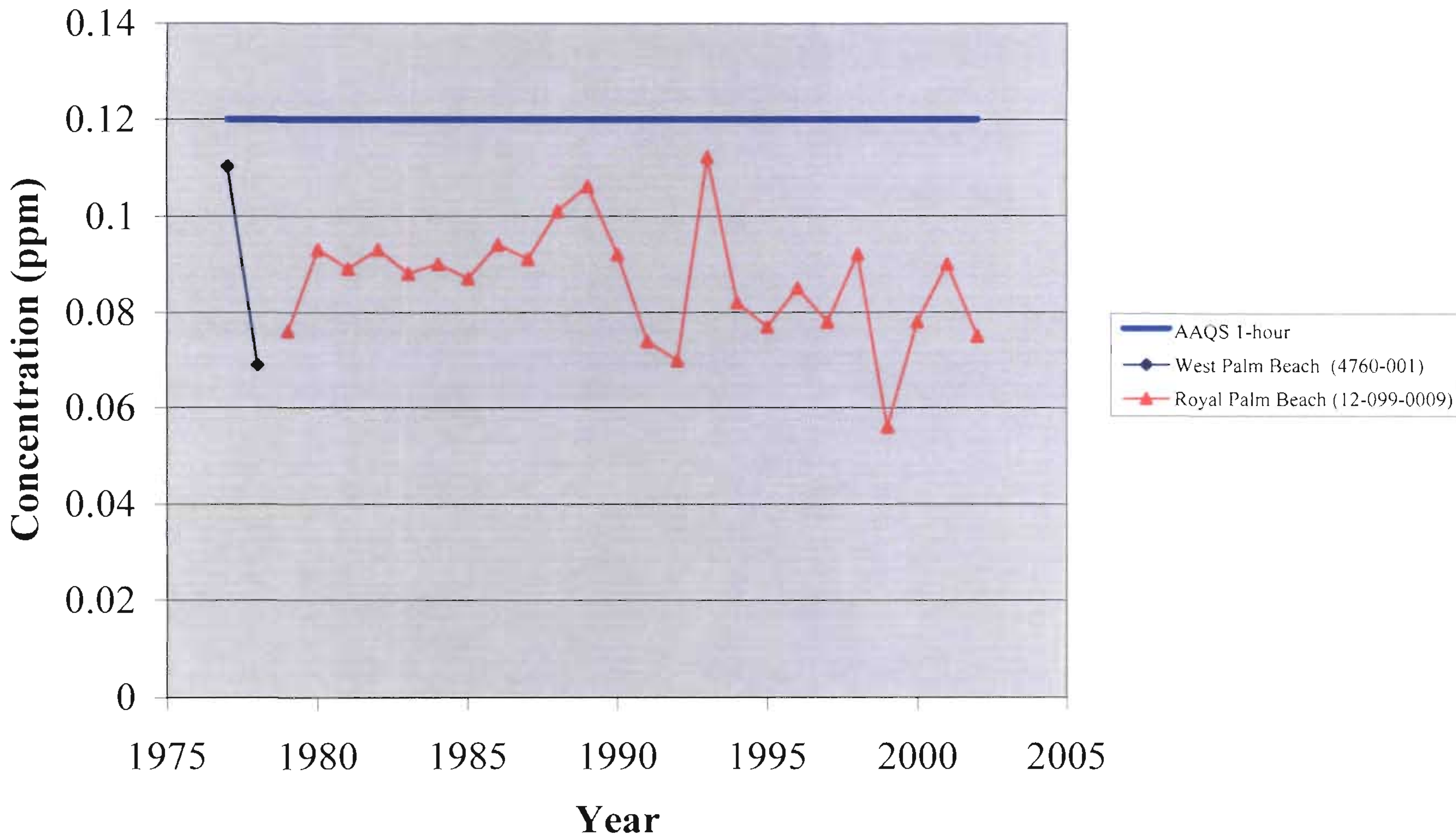
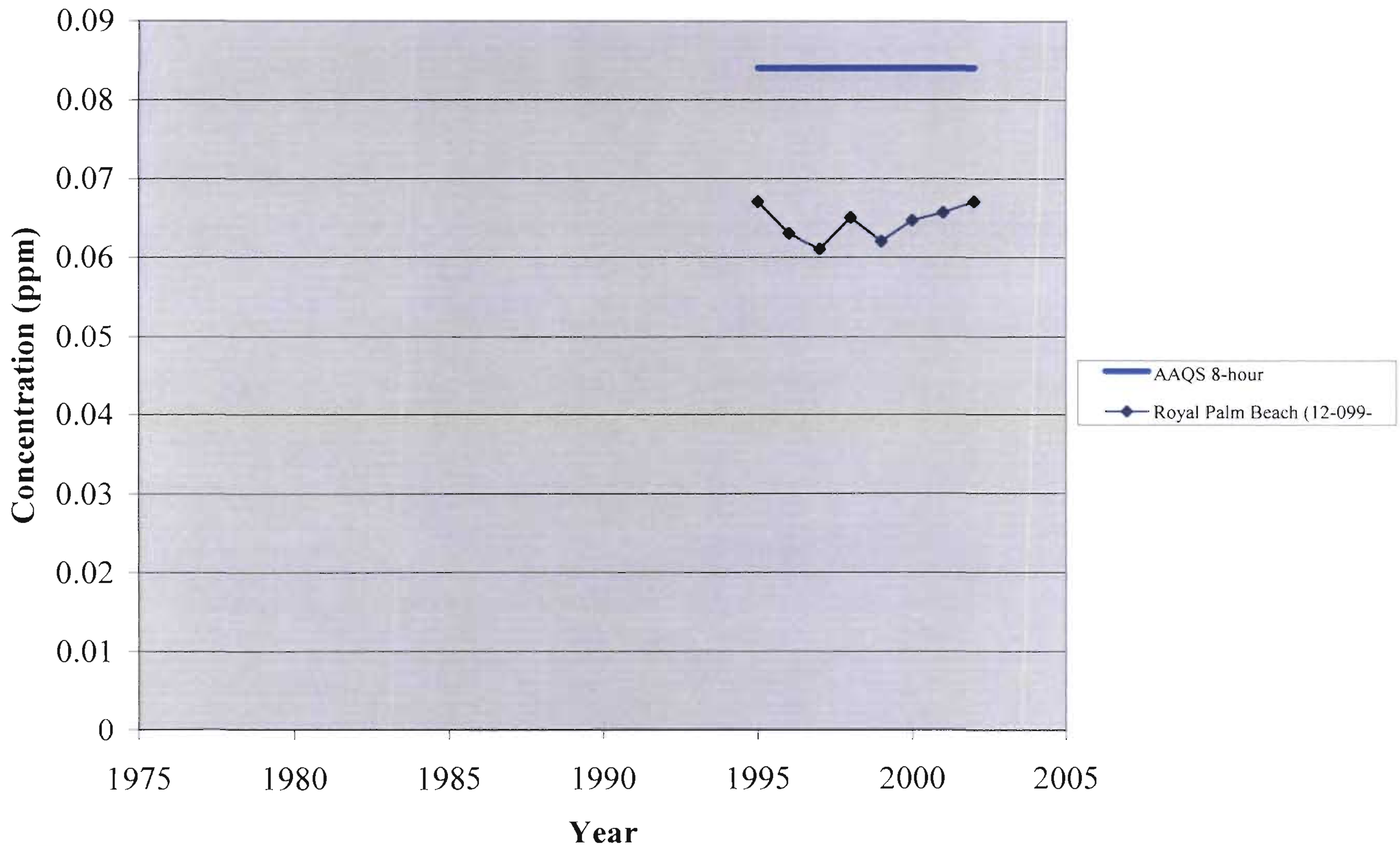


Figure 7-16. Measured 8-Hour Average Ozone Concentrations (3-Year Average of the 4th Highest Values) in Palm Beach County



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APPENDIX A

BOILER DESIGN DATA

APPENDIX A

BOILER NOS. 4 AND 5
DESIGN DATA

1. Steam Enthalpy Calculation

A. Steam conditions: 350 psig, 575°F
= 365 psia, 575°F

Enthalpy = 1,295 Btu/lb

B. Feedwater condition: 450 psig, 237°F
= 465 psia, 237°F

Enthalpy = 206 Btu/lb

C. Net Enthalpy: 1,295 – 206 = 1,089 Btu/lb steam

2. Heat Input Calculation (based on 55 percent thermal efficiency)

A. Maximum 1-hour:
170,000 lb/hr steam x 1,089 Btu/lb ÷ 0.55 = 336.6 MMBtu/hr

B. Maximum 24-hour:
160,000 lb/hr steam x 1,089 Btu/lb ÷ 0.55 = 316.8 MMBtu/hr

C. Annual rate:
150,000 lb/hr x 3,840 hr/yr x 1,089 Btu/lb ÷ 0.55 = 1,140,480 MMBtu/yr

3. Furnace Data

Boiler No. 4 manufacturer: Bigelow, 1965
Furnace Type = currently cell type, to be converted to inclined grate
Furnace Volume = 6,400 ft^3
Heat Release Rate (Bagasse) = 316.8 MMBtu/hr ÷ 6,400 ft^3 = 49,500 Btu/hr-ft^3

Boiler No. 5 manufacturer: Alpha, 1978
Furnace Type = currently cell type, to be converted to inclined grate
Furnace Volume = 6,400 ft^3
Heat Release Rate (Bagasse) = 316.8 MMBtu/hr ÷ 6,400 ft^3 = 49,500 Btu/hr-ft^3

VENDOR DATA
FOR PROPOSED MIST ELIMINATORS
FOR BOILER NOS. 4 AND 5

DEMISTER® Knitted Mesh Mist Eliminators

Bulletin 55B-2

KOCH-OTTO YORK™
SEPARATIONS TECHNOLOGY

- Easy to install in all process equipment
- Increase throughput capacity
- Prevent product loss
- Protect compressors, turbines and heat exchangers
- Improve product purity
- Available for emergency delivery

DEMISTER® Mist Eliminators What They Are

The DEMISTER® is an assembly of Yorkmesh™ knitted mesh supported on, and held down by high open area grids. It is made to any size and shape and may be installed in all new and existing process vessels. Wire used in DEMISTER® fabrication is smooth, clean, and bright for rapid liquid drainage. Stainless steels and exotic alloys are fully annealed to provide maximum corrosion resistance. Perfect fit is assured even in out-of-round vessels, eliminating all vapor by-passing.

DEMISTER® Mist Eliminators How They Work

When a vapor stream carrying entrained liquid droplets passes through a DEMISTER®, the vapor moves freely through the Yorkmesh™ but the inertia of the droplets causes them to contact the wire surfaces and be held there briefly. As more droplets collect, they grow in size, run off and fall free. Properly applied to specific process conditions, DEMISTER® mist eliminators achieve 99.9+wt % separation of liquid entrainment from any vapor stream.

Where to use a DEMISTER®

- **knockout drums and separators**–save on capital costs by decreasing vessel size–reduce compressor maintenance by preventing scale build-up
- **absorbers**–reduce overhead losses of glycols in dehydrators to no more than 0.0013 m³ liq/MMm³ (0.01 gal/MMSCF) natural gas–cut losses of absorption oil and amines in CO_2 systems
- **scrubbers**–reduce chemical discharges from Kraft mill smelt dissolver tank to less than 0.11 Kg/dry ton of pulp–improve scrubber efficiency by removing particulates carried in entrained liquids
- **distillation columns**–improve product purities and increase throughput capacities for petrochemicals, organic intermediates, fine chemicals
- **evaporators**–prevent carryover loss of valuable products, keep condensate TDS<10 ppm for highest quality boiler feed water–clean up vacuum ejector stream discharge–lower maintenance in vapor recompression systems
- **high pressure steam systems**–provide dry steam–cut TDS to <10 ppb in condensate–eliminate build-up on turbine blades
- **refinery towers**–increase throughput capacity–take deeper cuts for greater product yields–prolong catalyst life in downstream cracking and reforming units by reducing carbon and metals in side draws–use lower grade crudes

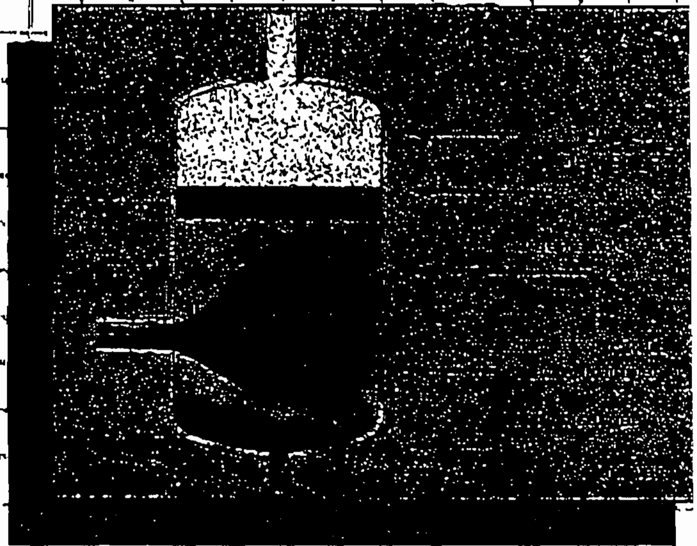

Figure 1. Schematic representation of DEMISTER® operation

Design Parameters

For general design, equation 1 has been used as a velocity guideline for many years:

Equation 1: $$V=K\,[(\rho_l-\rho_v)/\rho_v]^{1/2}$$

	Metric	English
V = design velocity	m/sec	ft/sec
ρ_l = liquid density	Kg/m³	lb/ft³
ρ_v = vapor density	Kg/m³	lb/ft³
K = capacity factor	m/sec	ft/sec

The maximum recommended value of "K" will vary depending on a variety of factors, including mesh style and thickness, liquid viscosity and surface tension, liquid entrainment loading, content of dissolved and suspended solids, and the operating temperature and pressure.

For over 40 years, the industry has used K = 0.107 m/sec (0.35 ft/sec) as a standard guideline for calculations. Traditional Otto York styles (see Table 1) have become the worldwide standard in the process industry. Excellent performance is obtained from 30-110% of the calculated value. ΔP is usually negligible, <25 mm H_2O (1" WC). For high vacuum applications, high performance is routinely achieved with ΔP on the order of 2-3mm H_2O (0.1" WC).

Over the past several years, Otto York has developed and refined a new family of styles, replacing the traditional styles Otto York originally introduced in 1950. These styles [illegible] advantage of improved knowledge on the internal wire geometry and how it affects capacity and performance. Compared to the older styles, the new Otto York styles provide:

- **20 to 40% higher design velocity (see Figure 3)**
- **10 to 15% lower pressure drop (see Figure 3)**
- **Equal efficiency (see Figure 2)**
- **Equal or better corrosion and fouling resistance**

For particular equipment and processes, Otto York engineers also utilize special families of mesh styles based on years of actual, in-plant performance experience to meet customer efficiency requirements. For example:

- Evaporator mist eliminators are customized to obtain customer specified steam condensate purity levels from 1 to 50 PPM.
- Steam drum mist eliminators will meet any specified steam condensate purity levels from <5 PPB to 1 PPM.
- Natural gas dehydration glycol losses to below 0.0013 m^3liquid/MMm^3 (0.01 gal/MMSCF) gas have been demonstrated.

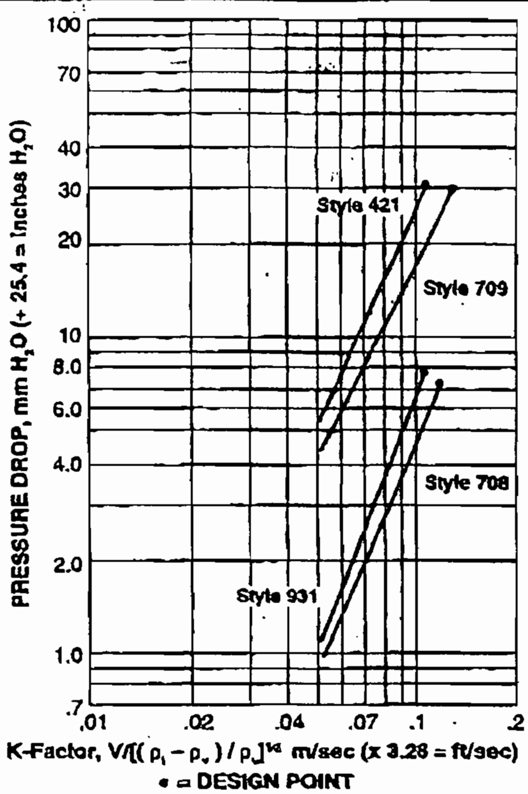

Figure 3. Pressure drop vs capacity factor. Liquid loading= 0.04m^3 min/m^2.

Materials of construction
All 300 and 400 series SS, alloys 200, 400, 600, 800, etc., alloy 20, titanium, tantalum, aluminum and copper, polypropylene, Teflon®, Halar® and Kynar® and any other mater[ial] which can be drawn or extruded. Teflon® is a registered trademark of E.I. Dupont de N[emours]. Halar® is a registered trademark of Ausimont. Kynar® is a registered trademark of Aloc[...]

Table 1: Typical DEMISTER® Style Improvements

Traditional Style	New Style	Capacity Gain	Efficiency Gain	Description
371	215	>35%	Same	Glass fiber & metal for maximum efficiency
326	194	>25%	Same	Ultra efficient design for fine particles
421	709	>20%	Same	Heavy duty, high efficiency design
431	172	>20%	Same	General purpose style
931	708	>20%	Same	High open area for viscous on dirty liquid

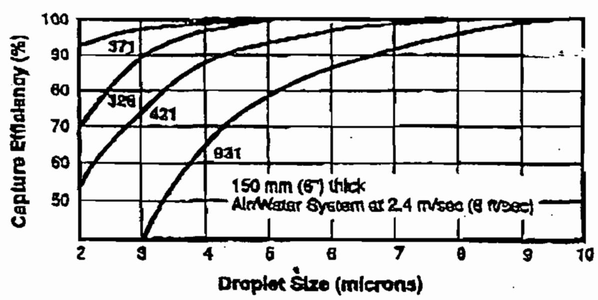

Figure 2. Capture efficiency vs particle size for four traditional DEMISTER® knitted mesh mist eliminators.

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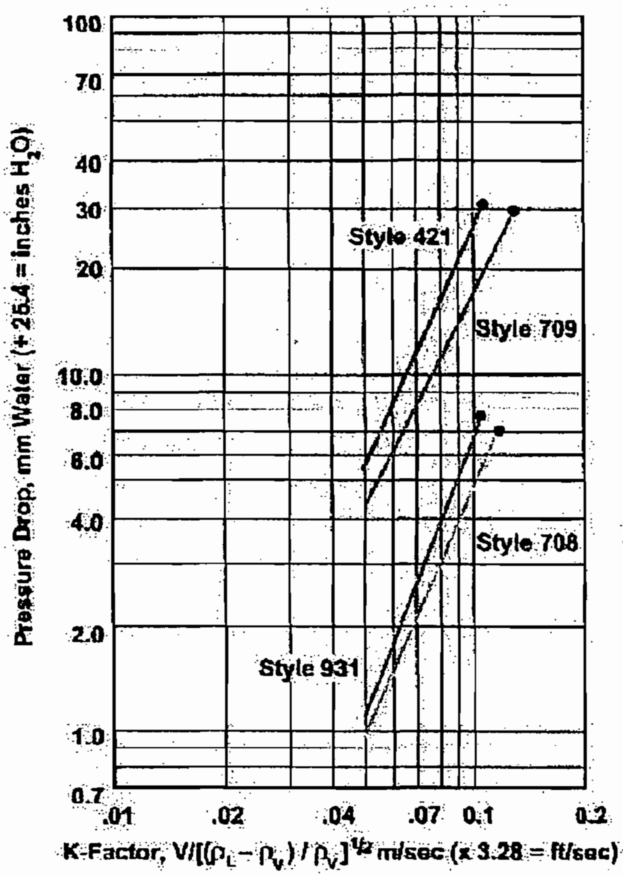
The State-of-the-Art DEMISTER® Mist Eliminator

Over the past several years, KOCH-OTTO YORK® has developed and refined a new family of styles, replacing the traditional styles KOCH-OTTO YORK® originally introduced shortly after founding the company in 1947. These new styles take advantage of improved knowledge about how the internal wire geometry affects capacity and performance in the same way that structured packing surpassed dumped packing performance. Compared to the older styles, the new KOCH-OTTO YORK® styles provide:

- 20% higher design velocity, or more.
- 10 to 15% lower pressure.
- Higher efficiency at design velocity.
- Equal or better corrosion and fouling resistance.

Table 3

Typical DEMISTER® Mist Eliminator Style Improvements				
Traditional Style	New Style	Capacity Gain	Efficiency Gain	Description
371	215	>35%	Same	Glass fiber & metal for maximum efficiency
326	194	>25%	Same	Ultra-efficiency design for fine particles
421	709	>20%	Same	Heavy duty, high efficiency design
431	172	>20%	Same	General purpose style
931	708	>22%	Same	High open area for viscous or dirty liquid



• = Design Point

Liquid loading = 0.04 m3/min/m2.

Figure 3. Pressure drop vs. Capacity factor.

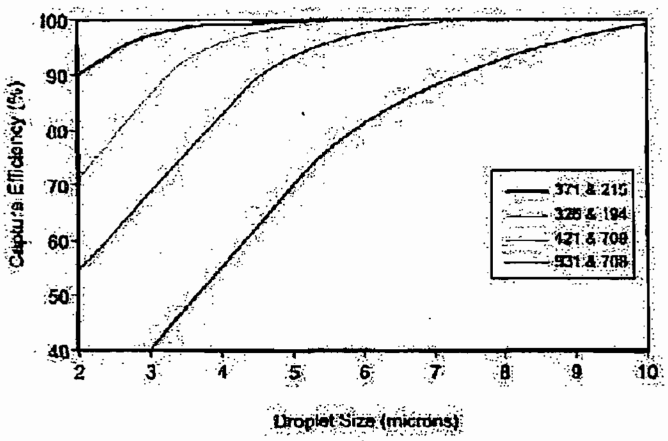


Figure 2. Capture efficiency vs. particle size for four traditional DEMISTER® mist eliminators and their high capacity equivalents in an air/water system at atmospheric conditions.

For particular equipment and processes, KOCH-OTTO YORK® engineers also utilize special families of mesh styles based on years of actual, in-plant performance experience to meet customer efficiency requirements.

Benefits of DEMISTER® Mist Eliminators

- Easy to install in all process equipment.
- Most cost effective solution when equipment sizes are set by other requirements.
- High efficiency with low pressure drop.
- Emergency delivery available.

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APPENDIX B

BASELINE EMISSIONS

Table B-1. 2003 Actual Annual Emissions for Boiler 4, Osceola Farms Company

	No. 6 Fuel Oil				Bagasse				
Pollutant	Fuel Usage[a] (gal/yr)	Emission Factor (lb/1,000 gal)	Ref.	Boiler Emissions (TPY)	Heat Input[a] (MMBtu/yr)	Emission Factor (lb/MMBtu)	Ref.	Boiler Emissions (TPY)	Total Emissions (TPY)
PM	265,356	1.82	(1)	0.24	834,074	0.192	(6)	80.07	80.31
PM_{10}	265,356	1.82	(2)	0.24	834,074	0.179	(7)	74.47	74.71
SO_2	265,356	157	(3)	20.83	834,074	0.05	(8)	20.85	41.68
NO_x	265,356	55	(4)	7.30	834,074	0.18	(6)	75.07	82.36
CO	265,356	5	(4)	0.66	834,074	4.66	(9)	1,943.4	1,944.06
VOC	265,356	0.28	(4)	0.037	834,074	0.23	(6)	95.9	95.96
Hg	265,356	1.13E-04	(12)	1.50E-05	834,074	7.95E-06	(10)	3.32E-03	3.33E-03
F	265,356	3.73E-02	(12)	4.95E-03	834,074	4.18E-04	(11)	0.174	0.179
Pb	265,356	1.51E-03	(12)	2.00E-04	834,074	2.44E-05	(11)	1.02E-02	1.04E-02
SAM	265,356	10	(5)	1.276	834,074	3.1.E-03	(5)	1.28	2.55

[a] Based on 2003 Annual Operating Report submitted to DEP.

References:
1. Based on AP-42 Section 1.3 (USEPA 9/98) formula 10(S) + 3 lb/1000 gal, where S = 1.0%, and scrubber removal efficiency of 86%.
2. PM_{10} assumed as 100% of PM.
3. Based on AP-42 Section 1.3 (USEPA 9/98) formula 157(S) lb/1000 gal, where S = 1.0%.
4. Based on AP-42 Section 1.3 (USEPA 9/98).
5. Based on emission factor for SO_2, assuming a 5% conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).
6. Average from all historical compliance test data. VOC reported as methane.
7. PM_{10} assumed as 93% of PM, based on test data from one bagasse boiler (EPA).
8. Based on sugar industry test data for bagasse boilers controlled by wet scrubbers.
9. Based on stack test data from Boiler No. 4 from Dec. 1993.
10. Based on Osceola mercury emission testing program for 1992-1993 crop season.
11. Based on 2 most recent stack tests for New Hope Power Partnership (Okeelanta Power) when burning bagasse.
12. From AP-42 Table 1.3-11 (USEPA 9/98).

Table B-2. 2002 Actual Annual Emissions for Boiler 4, Osceola Farms Company

	No. 6 Fuel Oil				Bagasse				
Pollutant	Fuel Usage[a] (gal/yr)	Emission Factor (lb/1,000 gal)	Ref.	Boiler Emissions (TPY)	Heat Input[a] (MMBtu/yr)	Emission Factor (lb/MMBtu)	Ref.	Boiler Emissions (TPY)	Total Emissions (TPY)
PM	264,200	1.82	(1)	0.24	774,386	0.192	(6)	74.34	74.58
PM_{10}	264,200	1.82	(2)	0.24	774,386	0.179	(7)	69.14	69.38
SO_2	264,200	157	(3)	20.74	774,386	0.05	(8)	19.36	40.10
NO_x	264,200	55	(4)	7.27	774,386	0.18	(6)	69.69	76.96
CO	264,200	5	(4)	0.66	774,386	4.66	(9)	1,804.3	1,804.98
VOC	264,200	0.28	(4)	0.037	774,386	0.23	(6)	89.1	89.09
Hg	264,200	1.13E-04	(12)	1.49E-05	774,386	7.95E-06	(10)	3.08E-03	3.09E-03
F	264,200	3.73E-02	(12)	4.93E-03	774,386	4.18E-04	(11)	0.162	0.167
Pb	264,200	1.51E-03	(12)	1.99E-04	774,386	2.44E-05	(11)	9.45E-03	9.65E-03
SAM	264,200	10	(5)	1.270	774,386	3.1.E-03	(5)	1.19	2.46

[a] Based on 2002 Annual Operating Report submitted to DEP.

References:
1. Based on AP-42 Section 1.3 (USEPA 9/98) formula 10(S) + 3 lb/1000 gal, where S = 1.0%, and scrubber removal efficiency of 86%.
2. PM_{10} assumed as 100% of PM.
3. Based on AP-42 Section 1.3 (USEPA 9/98) formula 157(S) lb/1000 gal, where S = 1.0%.
4. Based on AP-42 Section 1.3 (USEPA 9/98).
5. Based on emission factor for SO_2, assuming a 5% conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).
6. Average from all historical compliance test data. VOC reported as methane.
7. PM_{10} assumed as 93% of PM, based on test data from one bagasse boiler (EPA).
8. Based on sugar industry test data for bagasse boilers controlled by wet scrubbers.
9. Based on stack test data from Boiler No. 4 from Dec. 1993.
10. Based on Osceola mercury emission testing program for 1992-1993 crop season.
11. Based on 2 most recent stack tests for New Hope Power Partnership (Okeelanta Power) when burning bagasse.
12. From AP-42 Table 1.3-11 (USEPA 9/98).

Table B-3. Average 2002-2003 Actual Annual Emissions for Boiler 4, Osceola Farms Company

Pollutant	2003 Actual Emissions (TPY)	2002 Actual Emissions (TPY)	Average 2002-2003 Actual Emissions (TPY)
PM	80.31	74.58	77.45
PM_{10}	74.71	69.38	72.04
SO_2	41.68	40.10	40.89
NO_x	82.36	76.96	79.66
CO	1,944.06	1,804.98	1,874.52
VOC	95.96	89.09	92.52
Hg	3.33E-03	3.09E-03	3.21E-03
F	0.179	0.167	0.173
Pb	1.04E-02	9.65E-03	1.00E-02
SAM	2.55	2.46	2.50

Table B-4. 2003 Actual Annual Emissions for Boiler 5, Osceola Farms Company

	No. 6 Fuel Oil				Bagasse				
Pollutant	Fuel Usage[a] (gal/yr)	Emission Factor (lb/1,000 gal)	Ref.	Boiler Emissions (TPY)	Heat Input[a] (MMBtu/yr)	Emission Factor (lb/MMBtu)	Ref.	Boiler Emissions (TPY)	Total Emissions (TPY)
PM	274,640	1.17	(1)	0.161	827,036	0.145	(6)	59.96	60.12
PM_{10}	274,640	1.17	(2)	0.161	827,036	0.135	(7)	55.76	55.92
SO_2	274,640	157	(3)	21.559	827,036	0.05	(8)	20.68	42.24
NO_x	274,640	55	(4)	7.553	827,036	0.18	(6)	73.61	81.16
CO	274,640	5	(4)	0.687	827,036	4.39	(9)	1,815.3	1,816.03
VOC	274,640	0.28	(4)	0.038	827,036	0.16	(6)	66.2	66.20
Hg	274,640	1.13E-04	(12)	1.55E-05	827,036	7.95E-06	(10)	3.29E-03	3.30E-03
F	274,640	3.73E-02	(12)	5.12E-03	827,036	4.18E-04	(11)	0.173	0.178
Pb	274,640	1.51E-03	(12)	2.07E-04	827,036	2.44E-05	(11)	1.01E-02	1.03E-02
SAM	274,640	10	(5)	1.321	827,036	3.1.E-03	(5)	1.27	2.59

[a] Based on 2003 Annual Operating Report submitted to DEP.

References:
1. Based on AP-42 Section 1.3 (USEPA 9/98) formula 10(S) + 3 lb/1000 gal, where S = 1.0%, and scrubber removal efficiency of 91%.
2. PM_{10} assumed as 100% of PM.
3. Based on AP-42 Section 1.3 (USEPA 9/98) formula 157(S) lb/1000 gal, where S = 1.0%.
4. Based on AP-42 Section 1.3 (USEPA 9/98).
5. Based on emission factor for SO_2, assuming a 5% conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).
6. Average from all historical compliance test data. VOC reported as methane.
7. PM_{10} assumed as 93% of PM, based on test data from one bagasse boiler (EPA).
8. Based on sugar industry test data for bagasse boilers controlled by wet scrubbers.
9. Based on stack test data from Boiler No. 5 from Jan. 1994.
10. Based on Osceola mercury emission testing program for 1992-1993 crop season.
11. Based on 2 most recent stack tests for New Hope Power Partnership (Okeelanta Power) when burning bagasse.
12. From AP-42 Table 1.3-11 (USEPA 9/98).

Table B-5. 2002 Actual Annual Emissions for Boiler 5, Osceola Farms Company

	No. 6 Fuel Oil				Bagasse				
Pollutant	Fuel Usage[a] (gal/yr)	Emission Factor (lb/1,000 gal)	Ref.	Boiler Emissions (TPY)	Heat Input[a] (MMBtu/yr)	Emission Factor (lb/MMBtu)	Ref.	Boiler Emissions (TPY)	Total Emissions (TPY)
PM	317,200	1.17	(1)	0.186	754,137	0.145	(6)	54.52	54.71
PM_{10}	317,200	1.17	(2)	0.186	754,137	0.134	(7)	50.71	50.89
SO_2	317,200	157	(3)	24.900	754,137	0.05	(8)	18.85	43.75
NO_x	317,200	55	(4)	8.723	754,137	0.18	(6)	67.12	75.84
CO	317,200	5	(4)	0.793	754,137	4.39	(8)	1,655.3	1,656.12
VOC	317,200	0.28	(4)	0.044	754,137	0.16	(6)	60.3	60.38
Hg	317,200	1.13E-04	(11)	1.79E-05	754,137	7.95E-06	(9)	3.00E-03	3.02E-03
F	317,200	3.73E-02	(11)	5.92E-03	754,137	4.18E-04	(10)	0.158	0.164
Pb	317,200	1.51E-03	(11)	2.39E-04	754,137	2.44E-05	(10)	9.20E-03	9.44E-03
SAM	317,200	10	(5)	1.525	754,137	3.1.E-03	(5)	1.15	2.68

[a] Based on 2002 Annual Operating Report submitted to DEP.

References:
1. Based on AP-42 Section 1.3 (USEPA 9/98) formula 10(S) + 3 lb/1000 gal, where S = 1.0%, and scrubber removal efficiency of 91%.
2. PM_{10} assumed as 100% of PM.
3. Based on AP-42 Section 1.3 (USEPA 9/98) formula 157(S) lb/1000 gal, where S = 1.0%.
4. Based on AP-42 Section 1.3 (USEPA 9/98).
5. Based on emission factor for SO_2, assuming a 5% conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).
6. Average from all historical compliance test data. VOC reported as methane.
7. PM_{10} assumed as 93% of PM, based on test data from one bagasse boiler (EPA).
8. Based on sugar industry test data for bagasse boilers controlled by wet scrubbers.
9. Based on stack test data from Boiler No. 5 from Jan. 1994.
10. Based on Osceola mercury emission testing program for 1992-1993 crop season.
11. Based on 2 most recent stack tests for New Hope Power Partnership (Okeelanta Power) when burning bagasse.
12. From AP-42 Table 1.3-11 (USEPA 9/98).

Table B-6. Average 2002-2003 Actual Annual Emissions for Boiler 5, Osceola Farms Company

Pollutant	2003 Actual Emissions (TPY)	2002 Actual Emissions (TPY)	Average 2002-2003 Actual Emissions (TPY)
PM	60.12	54.71	57.42
PM_{10}	55.92	50.89	53.41
SO_2	42.24	43.75	42.99
NO_x	81.16	75.84	78.50
CO	1816.03	1656.12	1736.08
VOC	66.20	60.38	63.29
Hg	3.30E-03	3.02E-03	3.16E-03
F	0.178	0.164	0.171
Pb	1.03E-02	9.44E-03	9.87E-03
SAM	2.59	2.680	2.63

Table B-7. Current Short-Term Emissions for Boiler No. 4 , Osceola Farms Company

	No. 6 Fuel Oil				Bagasse				Total
Regulated Pollutant	Emission Factor (lb/1000 gal)	Ref.	Activity Factor gal/hr)	Current Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Current Emissions (lb/hr)	Current Emissions (lb/hr)
Particulate (PM)	1.82	(1)	--	--	0.21	(6)	253.0	53.13	53.13
Particulate (PM_{10})	1.82	(2)	--	--	0.195	(7)	253.0	49.41	49.41
Sulfur Dioxide	157	(3)	234	36.74	0.05	(11)	223.3	11.17	47.90
Nitrogen Oxides	55	(4)	234	12.87	0.152	(6)	223.3	33.94	46.81
Carbon Monoxide	5	(4)	--	--	3.98	(11)	253.0	1,006.94	1,006.94
VOC	0.28	(4)	--	--	0.258	(6)	253.0	65.27	65.27
Mercury	1.13E-04	(10)	--	--	7.95E-06	(8)	253.0	0.0020	0.0020
Fluorides	3.73E-02	(10)	--	--	4.18E-04	(9)	253.0	0.106	0.11
Lead	1.51E-03	(10)	--	--	2.44E-05	(9)	253.0	0.0062	0.006
Sulfuric Acid Mist --3-hr Average	9.62	(5)	234	2.25	0.0031	(5)	223.3	0.68	2.93

Note: Current emissions for PM, PM10, Hg, Fl, and Pb based on bagasse-firing and maximum steam production during last two compliance tests.
Other pollutants based on actual steam production and fuel oil usage on Oct. 19, 2001.

References:

1. Based on AP-42 Section 1.3 (USEPA 9/98) formula 10(S) + 3 lb/1000 gal, where S = 1.0%, and scrubber removal efficiency of 86%.
2. PM_{10} assumed as 100% of PM.
3. Based on AP-42 Section 1.3 (USEPA 9/98) formula 157(S) lb/1000 gal, where S = 1.0%.
4. Based on AP-42 Section 1.3 (USEPA 9/98).
5. Based on emission factor for SO_2, assuming a 5% conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).
6. Based on 11/15/2001 compliance test average. VOC reported as carbon.
7. PM_{10} based on 93% of PM, based on one stack test (EPA).
8. Based on Osceola mercury emission testing program for 1992-1993 crop season.
9. Based on average emissions from New Hope Power Partnership most recent two stack tests when burning bagasse only.
10. From AP-42 Table 1.3-11 (USEPA 9/98).
11. Based on historical stack test data from 1989-1990.

Table B-8. Current Short-Term Emissions for Boiler No. 5 , Osceola Farms Company

	No. 6 Fuel Oil				Bagasse				Total
Regulated Pollutant	Emission Factor (lb/1000 gal)	Ref.	Activity Factor gal/hr)	Current Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Current Emissions (lb/hr)	Current Emissions (lb/hr)
Particulate (PM)	1.82	(1)	--	--	0.180	(6)	277.9	50.02	50.02
Particulate (PM_{10})	1.82	(2)	--	--	0.167	(7)	277.9	46.52	46.52
Sulfur Dioxide	157	(3)	258	40.51	0.05	(11)	246.9	12.35	52.85
Nitrogen Oxides	55	(4)	258	14.19	0.178	(6)	246.9	43.95	58.14
Carbon Monoxide	5	(4)	--	--	3.98	(11)	290.2	1,155.00	1,155.00
VOC	0.28	(4)	--	--	0.301	(6)	277.9	83.65	83.65
Mercury	1.13E-04	(10)	--	--	7.95E-06	(8)	277.9	0.0022	0.0022
Fluorides	3.73E-02	(10)	--	--	4.18E-04	(9)	277.9	0.116	0.12
Lead	1.51E-03	(10)	--	--	2.44E-05	(9)	277.9	0.0068	0.007
Sulfuric Acid Mist --3-hr Average	9.62	(5)	258	2.48	0.0031	(5)	246.9	0.76	3.24

Note: Current emissions for PM, PM10, Hg, Fl, and Pb based on bagasse-firing and maximum steam production during last two compliance tests.
Other pollutants based on actual steam production and fuel oil usage on Oct. 19, 2001.

References:

1. Based on AP-42 Section 1.3 (USEPA 9/98) formula 10(S) + 3 lb/1000 gal, where S = 1.0%, and scrubber removal efficiency of 86%.
2. PM_{10} assumed as 100% of PM.
3. Based on AP-42 Section 1.3 (USEPA 9/98) formula 157(S) lb/1000 gal, where S = 1.0%.
4. Based on AP-42 Section 1.3 (USEPA 9/98).
5. Based on emission factor for SO_2, assuming a 5% conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).
6. Based on 11/13/2001 compliance test average. VOC reported as carbon.
7. PM_{10} based on 93% of PM, based on one stack test (EPA).
8. Based on Osceola mercury emission testing program for 1992-1993 crop season.
9. Based on average emissions from New Hope Power Partnership most recent two stack tests when burning bagasse only.
10. From AP-42 Table 1.3-11 (USEPA 9/98).
11. Based on historical stack test data from 1989-1990.

APPENDIX C

GOOD COMBUSTION PRACTICES
FOR BOILER NOS. 4 AND 5

APPENDIX C
GOOD COMBUSTION PRACTICES
FOR BOILER NOS. 4 AND 5

Purpose of GCP Plan

The determination of BACT for PM, NO_x, CO, and VOC emissions from Boiler Nos. 4 and 5 relies on "good combustion practices" (GCPs). Control and minimization of these emissions relies on such practices. The purpose of this document is to summarize the operational, maintenance, and monitoring procedures that will lead to the minimization of PM, CO and VOC emissions, and the optimization of NO_x emissions, consistent with good combustion practices.

Off-Season Equipment Preparation

Prior to each harvest season, the following activities will be performed:

1. The boiler proper, its air ductwork, bagasse feeders, grates, and air heaters will be properly cleaned, inspected and repaired.
2. All refractory and boiler casing will be inspected and repaired where needed.
3. Outside of boiler tubes will have loose scale removed and boiler will be cleaned of loose scale, sand, and other debris.
4. Boiler grates will be inspected and cleaned as well as being checked for mechanical operation.
5. All fans and fan drives will be inspected and repaired as needed.
6. All pumps and pump drives will be inspected and repaired as needed.
7. All oil burners will be cleaned and inspected as well as related piping, atomizing steam, and air registers.
8. The wet scrubbers will be inspected, cleaned, and repaired.
9. All instruments for boiler operation and control (including oxygen and carbon monoxide process monitors) are inspected, repaired, and calibrated as required. This information will be recorded by the instrument shop in its repair log.

Training

Prior to each harvest season, an instructional program shall be developed and presented to all boiler operators and boiler room supervisors regarding the following items:

- Efficient combustion: minimizing CO, PM, and VOC emissions while optimizing NO_x emissions;
- Reducing startup emissions;
- Proper wet scrubber operation;
- Record keeping required by the air permit; and
- Using process monitors for CO and O_2 to promote good combustion characteristics in the boiler.

The senior most experienced boiler supervisor shall instruct other boiler room supervisors, boiler operators, and other appropriate personnel in proper boiler and scrubber operations. The training will impress upon supervisors and operators the importance of proper boiler operation in order to minimize emissions.

Good Combustion Practices - Operation

Emissions of CO, PM, and VOC shall be minimized by ensuring efficient combustion through the proper application of GCPs. To provide reasonable assurance that GCPs are being employed, the boiler operator shall:

1. Maintain the steam production rate at the optimal rate by controlling feed of bagasse fuel into the boiler. Sufficient combustion air shall be maintained to promote good combustion.

2. Periodically view the stack plume to visually confirm that good combustion is taking place. If an abnormal plume is observed, the operator shall immediately take corrective action. The boiler operator will log the occurrence and duration of all such events in the boiler operation log, along with the corrective action taken. These records will be kept for a period of at least two years.

3. Examine the boiler grates at least twice per shift for proper fuel distribution and make appropriate adjustments. Unusual observations shall be logged.

4. Perform a walk-around inspection of the boiler once per day shift to check and repair the following: fans, pumps, casing, ducting, scrubber, and monitoring equipment.

5. Inspect the burners once per shift and clean as necessary.

These actions may be performed by the operator or other personnel under the operator's supervision. The information collected shall be reported to the boiler operator.

6. Process monitors shall be installed to monitor the O_2 content and the CO content of the boiler flue gas. The instrument readout shall be located in the boiler control room to provide real time data to the boiler operator and will display the instantaneous and 1-hour block average. The boiler operators will be instructed in the use of the O_2 and CO flue gas process monitors for combustion control and to ensure sufficient excess air levels. The boiler operators shall periodically observe each process monitor and adjust the boiler operation, consistent with good combustion practices. The O_2 process monitor shall be equipped with an alarm with a set point at XX%* (minimum) flue gas O_2 content based upon a 1-hour block average. The CO process monitor shall be equipped with an alarm with a set point at XX ppm* (maximum) flue gas CO concentration based on a 1-hour block average. When an alarm on either monitor is tripped, the operator shall take corrective actions to adjust the boiler operation consistent with good combustion practices. Corrective actions include, but are not limited to, adjusting the air-to-fuel ratio and adjusting the ratio of under-fire air to over-fire air. Corrective actions shall continue until the CO and O_2 flue gas concentrations are within the levels representing good combustion practices.

   Note: Emissions of NO_x shall be optimized by the proper application of good combustion practices. However, the same operating practices that result in efficient combustion (higher furnace temperatures and excess air rates) may tend to raise NO_x levels. The good combustion practices indicated above encourage the reduction of CO emissions while maintaining NO_x emissions within acceptable levels.

* Values to be determined from correlation testing.

APPENDIX D

TEST DATA FOR BOILER NOS. 2 THROUGH 6 AND NEW HOPE POWER

Table D-1. Emission Test Averages Performed on Bagasse Boilers at Osceola Farms

Unit	Boiler Type	Test Date	Number of runs	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate (TPH)	SO2 Emissions (EPA Method 6)		PM Emissions (EPA Method 5)		CO Emissions (EPA Method 10)		NOx Emissions (EPA Method 7E)		VOC Emissions as Carbon (EPA Method 18/25A)		THC Emissions as Carbon (EPA Method 18/25A)		Methane Emissions as Carbon (EPA Method 18/25A)		Oxygen (%, dry)	Excess Air %
							lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu		
Boiler 2	Inclined Grate	03/04/93	2	124,622	246.85	34.28	85.10	0.346			1480.55	5.998	23.5	0.095							5.95	40
Boiler 2	Inclined Grate	01/15/94	3	122,667	243.57	33.83					2929.67	12.037	15.4	0.063							8.00	61
Boiler 2	Inclined Grate	01/27/95	3	124,891	248.70	34.54			32.17	0.130			32.2	0.130								
Boiler 2	Inclined Grate	11/30/95	3	183,217	238.53	33.13			43.96	0.184											5.40	35
Boiler 2	Inclined Grate	11/20/97	3	132,800	260.80	36.22			42.87	0.164												
Boiler 2	Inclined Grate	01/14/99	3	128,640	253.43	35.20							54.0	0.217	2.61	0.010	2.9	0.012	0.3	0.001	6.69	47
Boiler 2	Inclined Grate	02/19/99	3	124,533	244.23	33.92			37.18	0.153											5.02	31
Boiler 2	Inclined Grate	11/17/99	3	137,067	268.64	37.31			46.87	0.174			38.2	0.138	47.58	0.165	52.2	0.191	4.5	0.016	6.96	50
Boiler 2	Inclined Grate	11/15/00	3	128,533	250.37	34.77			43.85	0.172			51.9	0.211	85.21	0.339	89.1	0.356	3.6	0.015	7.76	59
Boiler 2	Inclined Grate	11/26/01	3	139,200	273.93	38.04			43.93	0.161			47.5	0.178	83.71	0.411	87.2	0.308	3.3	0.012	8.29	65
Boiler 2	Inclined Grate	11/20/02	3	126,667	248.97	34.58			45.55	0.184			49.8	0.193	79.85	0.308	83.5	0.335	3.4	0.014	9.99	91
Boiler 2	Vibrating Grate	12/11/03	3	121,653	238.80	33.16			45.70	0.192			56.87	0.237	40.00	0.172	86.3	0.365			8.58	70
	Number of Tests			12	12	12	1	1	9	9	2	2	9	9	6	6	6	6	5	5	10	10
	MEAN			**132,874**	**251.40**	**34.92**	**85.10**	**0.346**	**42.45**	**0.168**	**2205.11**	**9.018**	**41.0**	**0.162**	**56.49**	**0.234**	**66.9**	**0.261**	**3.0**	**0.012**	**7.3**	**55**
	MINIMUM			121,653	238.53	33.13			32.17	0.130	1480.55	5.998	15.4	0.063	2.61	0.010	2.9	0.012	0.3	0.001	5.0	31
	MAXIMUM			183,217	273.93	38.04			46.87	0.192	2929.67	12.037	56.9	0.237	85.21	0.411	89.1	0.365	4.5	0.016	10.0	91
	STD DEVIATION			16,784	11.16	1.55			4.74	0.019	1024.68	4.271	14.6	0.059	32.76	0.146	34.2	0.138	1.6	0.006	1.6	18
	95% CL OF TESTS			**166,442**	**273.72**	**38.01**		**0.797**	**51.93**	**0.207**	**4254.47**	**17.559**	**70.2**	**0.281**	**122.01**	**0.527**	**135.3**	**0.536**	**6.2**	**0.024**	**10.4**	**91**
	GEOMETRIC MEAN			**132,055**	**251.18**	**34.88**		**0.306**	**42.19**	**0.167**	**2082.67**	**8.497**	**38.1**	**0.151**	**37.61**	**0.152**	**45.2**	**0.176**	**2.3**	**0.009**	**7.1**	**52**

Table D-1. Emission Test Averages Performed on Bagasse Boilers at Osceola Farms

Unit	Boiler Type	Test Date	Number of runs	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate (TPH)	SO2 Emissions (EPA Method 6)		PM Emissions (EPA Method 5)		CO Emissions (EPA Method 10)		NOx Emissions (EPA Method 7E)		VOC Emissions as Carbon (EPA Method 18/25A)		THC Emissions as Carbon (EPA Method 18/25A)		Methane Emissions as Carbon (EPA Method 18/25A)		Oxygen (%, dry)	Excess Air %
							lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu		
Boiler 3	Inclined Grate	11/09/95	3	197,875	258.40	35.89			45.94	0.178											6.03	41
Boiler 3	Inclined Grate	11/17/97	3	144,600	283.47	39.37			34.08	0.120												
Boiler 3	Inclined Grate	11/20/98	3	131,354	248.43	34.50			30.59	0.124											8.07	62
Boiler 3	Inclined Grate	11/19/99	3	133,674	261.91	36.38			49.33	0.188											5.07	30
Boiler 3	Inclined Grate	11/10/00	3	138,600	271.4	37.70			28.77	0.106												
Boiler 3	Inclined Grate	11/21/01	3	140,400	276.2	38.37			45.99	0.167											6.30	43
Boiler 3	Inclined Grate	11/14/02	3	130,800	256.6	35.64			33.64	0.131											6.50	45
Boiler 3	Inclined Grate	11/20/03	3	126,198	247.9	34.43			39.80	0.160											9.83	89
	Number of Tests			8	8	8			8	8											6	6
	MEAN			**142,937**	**263.04**	**36.53**			**38.52**	**0.147**											**7.0**	**52**
	MINIMUM			126,198	247.90	34.43			28.77	0.106											5.1	30
	MAXIMUM			197,875	283.47	39.37			49.33	0.188											9.8	89
	STD DEVIATION			22,971	12.92	1.79			7.84	0.030											1.7	21
	95% CL OF TESTS			**188,879**	**288.89**	**40.12**			**54.21**	**0.207**											**10.4**	**94**
	GEOMETRIC MEAN			**141,573**	**262.77**	**36.50**			**37.82**	**0.144**											**6.8**	**49**

Table D-1. Emission Test Averages Performed on Bagasse Boilers at Osceola Farms

Unit	Boiler Type	Test Date	Number of runs	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate (TPH)	SO2 Emissions (EPA Method 6)		PM Emissions (EPA Method 5)		CO Emissions (EPA Method 10)		NOx Emissions (EPA Method 7E)		VOC Emissions as Carbon (EPA Method 18/25A)		THC Emissions as Carbon (EPA Method 18/25A)		Methane Emissions as Carbon (EPA Method 18/25A)		Oxygen (%, dry)	Excess Air %
							lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu		
Boiler 4	Horseshoe	12/04/93	3	139,000	274.6	38.14					1272.23	4.655	42.8	0.156							9.99	91
Boiler 4	Horseshoe	11/11/94	3	135,116	263.6	36.61			56.27	0.204			56.3	0.214								
Boiler 4	Horseshoe	11/13/95	3	155,000	295.7	41.07			41.33	0.140											7.80	60
Boiler 4	Horseshoe	11/10/97	3	123,000	236.0	32.78			39.16	0.166											5.00	31
Boiler 4	Horseshoe	11/18/98	3	125,077	238.0	33.05			60.66	0.255			55.6	0.234	25.52	0.107	26.7	0.112	1.2	0.005	8.63	70
Boiler 4	Horseshoe	11/10/99	3	135,423	259.7	36.06			38.74	0.149			40.4	0.162	10.93	0.042	11.6	0.045	0.7	0.003	10.03	92
Boiler 4	Horseshoe	11/06/00	3	135,000	263.6	36.61			65.32	0.248			48.9	0.193	59.24	0.224	60.9	0.231	1.5	0.006	9.57	84
Boiler 4	Horseshoe	11/15/01	3	128,500	253.0	35.15			52.71	0.208			39.3	0.152	65.38	0.258	66.9	0.264	1.4	0.006	8.06	62
Boiler 4	Horseshoe	11/08/02	3	116,500	228.6	31.76			44.17	0.193			48.1	0.212	47.71	0.209	50.2	0.217	2.3	0.010	9.99	93
Boiler 4	Horseshoe	11/12/03	3	128,306	250.8	34.83			40.92	0.163			31.7	0.126	50.69	0.200	50.8	0.200	0.8	0.003	10.23	98
	Number of Tests			10	10	10			9	9	1	1	8	8	6	6	6	6	6	6	9	9
	MEAN			**132,092**	**256.36**	**35.61**			**48.81**	**0.192**	**1272.23**	**4.655**	**45.4**	**0.181**	**43.24**	**0.173**	**44.5**	**0.178**	**1.3**	**0.005**	**8.8**	**76**
	MINIMUM			116,500	228.63	31.76			38.74	0.140			31.7	0.126	10.93	0.042	11.6	0.045	0.7	0.003	5.0	31
	MAXIMUM			155,000	295.73	41.07			65.32	0.255			56.3	0.234	65.38	0.258	66.9	0.264	2.3	0.010	10.2	98
	STD DEVIATION			10,559	19.89	2.76			10.11	0.041			8.4	0.038	20.88	0.082	21.2	0.083	0.6	0.003	1.7	22
	95% CL OF TESTS			**153,210**	**296.14**	**41.13**			**69.03**	**0.274**		**8.079**	**62.3**	**0.256**	**85.00**	**0.337**	**86.9**	**0.344**	**2.5**	**0.011**	**12.2**	**120**
	GEOMETRIC MEAN			**131,724**	**255.68**	**35.51**			**47.92**	**0.188**		**4.413**	**44.7**	**0.178**	**37.11**	**0.149**	**38.5**	**0.154**	**1.2**	**0.005**	**8.6**	**72**

Table D-1. Emission Test Averages Performed on Bagasse Boilers at Osceola Farms

Unit	Boiler Type	Test Date	Number of runs	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate (TPH)	SO2 Emissions (EPA Method 6)		PM Emissions (EPA Method 5)		CO Emissions (EPA Method 10)		NOx Emissions (EPA Method 7E)		VOC Emissions as Carbon (EPA Method 18/25A)		THC Emissions as Carbon (EPA Method 18/25A)		Methane Emissions as Carbon (EPA Method 18/25A)		Oxygen (%, dry)	Excess Air %
							lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu		
Boiler 5	Horseshoe	01/06/94	3	153,868	306.43	42.56					1345.30	4.392	48.4	0.158							7.51	56
Boiler 5	Horseshoe	11/09/94	3	154,284	304.40	42.28			35.97	0.119			35.8	0.118							8.25	64
Boiler 5	Horseshoe	01/13/95	3	158,100	313.88	43.59							39.5	0.126							5.97	39
Boiler 5	Horseshoe	11/04/95	3	156,884	306.97	42.63			47.46	0.154											6.82	49
Boiler 5	Horseshoe	11/09/95	3	154,284	304.40	42.28			22.95	0.075											7.47	56
Boiler 5	Horseshoe	11/07/97	3	140,308	276.80	38.44			43.84	0.158												
Boiler 5	Horseshoe	01/11/99	3	138,000	274.15	38.08							63.9	0.236	2.42	0.009	2.9	0.01	0.5	0.002	10.61	102
Boiler 5	Horseshoe	02/17/99	3	137,400	270.65	37.59			39.72	0.147											9.10	76
Boiler 5	Horseshoe	11/08/99	3	134,400	265.24	36.84			44.26	0.166			57.9	0.215	3.37	0.012	3.9	0.014	0.0	0.002	10.40	98
Boiler 5	Horseshoe	11/02/00	3	144,000	283.00	39.30			44.96	0.156			66.7	0.236	13.28	0.047	14.2	0.050	0.9	0.003	9.54	83
Boiler 5	Horseshoe	11/13/01	3	140,730	277.93	38.60			49.82	0.180			48.8	0.178	82.75	0.301	86.7	0.311	3.8	0.014	7.27	53
Boiler 5	Horseshoe	11/06/02	3	147,900	290.23	40.31			41.86	0.145			48.0	0.166	82.09	0.285	87.2	0.301	4.9	0.017	9.99	91
Boiler 5	Horseshoe	11/18/03	3	137,842	273.13	37.94			41.20	0.151			54.5	0.200	18.21	0.067	18.3	0.067			10.08	93
	Number of Tests			13	13	13			10	10	1	1	9	9	6	6	6	6	5	5	8	8
	MEAN			**146,000**	**288.25**	**40.03**			**41.20**	**0.145**	**1345.30**	**4.392**	**51.5**	**0.181**	**33.69**	**0.120**	**35.5**	**0.126**	**2.0**	**0.007**	**8.9**	76
	MINIMUM			134,400	265.24	36.84			22.95	0.075			35.8	0.118	2.42	0.009	2.9	0.011	0.0	0.002	6.8	49
	MAXIMUM			158,100	313.88	43.59			49.82	0.180			66.7	0.236	82.75	0.301	87.2	0.311	4.9	0.017	10.6	102
	STD DEVIATION			8,519	16.82	2.34			7.51	0.029			10.3	0.044	38.22	0.136	40.3	0.141	2.2	0.007	1.5	21
	95% CL OF TESTS			**163,038**	**321.89**	**44.71**			**56.21**	**0.204**		**5.812**	**72.2**	**0.269**	**110.12**	**0.392**	**116.1**	**0.409**	**6.4**	**0.022**	**11.9**	**118**
	GEOMETRIC MEAN			**145,771**	**287.80**	**39.97**			**40.43**	**0.142**		**4.355**	**50.5**	**0.176**	**15.41**	**0.056**	**16.8**	**0.060**	**0.8**	**0.005**	**8.4**	69

Table D-1. Emission Test Averages Performed on Bagasse Boilers at Osceola Farms

Unit	Boiler Type	Test Date	Number of runs	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate (TPH)	SO2 Emissions (EPA Method 6)		PM Emissions (EPA Method 5)		CO Emissions (EPA Method 10)		NOx Emissions (EPA Method 7E)		VOC Emissions as Carbon (EPA Method 18/25A)		THC Emissions as Carbon (EPA Method 18/25A)		Methane Emissions as Carbon (EPA Method 18/25A)		Oxygen (%, dry)	Excess Air %
							lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu		
Boiler 6	Traveling Grate	01/20/95	3	176,500	351.50	48.82			37.50	0.107			20.20	0.057							5.80	38
Boiler 6	Traveling Grate	01/24/95	3	174,429	347.17	48.22			45.93	0.134											6.00	39
Boiler 6	Traveling Grate	11/07/95	3	173,452	340.47	47.29			39.90	0.117											6.70	47
Boiler 6	Traveling Grate	11/12/97	3	167,500	329.70	45.79			31.41	0.095												
Boiler 6	Traveling Grate	01/07/99	3	153,333	296.83	41.23			41.06	0.138											7.53	56
Boiler 6	Traveling Grate	11/12/99	3	149,167	292.72	40.66			39.77	0.136											8.43	67
Boiler 6	Traveling Grate	11/08/00	3	165,000	316.97	44.02			29.65	0.094												
Boiler 6	Traveling Grate	11/19/01	3	169,167	333.37	46.30			35.03	0.105											8.37	66
Boiler 6	Traveling Grate	11/12/02	3	142,500	279.27	38.79			35.65	0.127											8.37	66
Boiler 6	Traveling Grate	11/14/03	3	144,121	283.23	39.34			34.81	0.123											10.07	92
	Number of Tests			10	10	10			10	10			1	1							8	8
	MEAN			**161,517**	**317.12**	**44.05**			**37.07**	**0.118**			**20.2**	**0.057**							**7.7**	**59**
	MINIMUM			142,500	279.27	38.79			29.65	0.094											5.8	38
	MAXIMUM			176,500	351.50	48.82			45.93	0.138											10.1	92
	STD DEVIATION			13,012	27.16	3.77			4.81	0.017											1.4	18
	95% CL OF TESTS			**187,541**	**371.45**	**51.59**			**46.69**	**0.151**				**0.062**							**10.5**	**95**
	GEOMETRIC MEAN			**161,035**	**316.06**	**43.90**			**36.79**	**0.117**				**0.057**							**7.5**	**57**

Table D-2. Summary of Okeelanta Power/New Hope Power Stack Tests - Bagasse Firing

Pollutant	Stack Testing: 1/22/99-2/5/99 Pre-Mechanical Dust Collectors			Stack Testing: 12/99 - 01/00 Pre-Mechanical Dust Collectors			Stack Testing: 01/3/01-01/23/01 Post-Mechanical Dust Collectors		
	Unit A (lb/MMBtu)	Unit B (lb/MMBtu)	Unit C (lb/MMBtu)	Unit A (lb/MMBtu)	Unit B (lb/MMBtu)	Unit C (lb/MMBtu)	Unit A (lb/MMBtu)	Unit B (lb/MMBtu)	Unit C (lb/MMBtu)
Particulate (TSP)	0.27	0.12	0.20	0.221	0.039	0.230	0.016	0.021	0.010
Particulate (PM_{10})	0.02	0.01	0.02	0.0282	0.0092	0.0308	0.0153	0.0232	0.0131
Sulfur Dioxide	0.02	0	0	0.0011	0.0080	0.0143	0.022	0.019	0.014
Nitrogen Oxides	0.13	0.12	0.13	0.138	0.142	0.179	0.19	0.17	0.17
Carbon Monoxide	0.16	0.26	0.28	0.377	0.354	0.299	0.24	0.21	0.24
Volatile Organic Compounds	0.01	0.02	0.007	0.010	0.007	0.012	0.007	0.008	0.01
Arsenic	3.18E-05	6.50E-06	4.92E-06	1.40E-06	5.42E-06	8.46E-06	6.34E-05	4.17E-05	4.40E-05
Beryllium	<3.77E-07	<3.94E-07	<1.25E-07	<2.22E-07	<2.34E-07	<2.52E-07	<1.10E-07	<1.07E-07	1.76E-07
Chromium	9.33E-06	5.85E-06	5.40E-06	2.15E-06	4.54E-06	6.57E-06	5.22E-05	2.91E-05	2.41E-05
Copper	2.55E-05	1.03E-05	1.33E-05	8.67E-06	1.43E-05	2.67E-05	2.38E-05	2.23E-05	1.18E-05
Lead	2.00E-05	7.30E-06	6.30E-06	3.41E-06	6.68E-06	9.77E-06	3.81E-05	4.76E-05	1.63E-05
Mercury	4.41E-07	3.83E-07	5.41E-07	1.26E-07	1.68E-07	5.34E-07	1.29E-06	1.41E-06	8.38E-07
Fluorides	7.06E-05	4.07E-05	3.04E-05	3.70E-04	4.40E-04	3.90E-04	6.00E-04	4.00E-04	3.00E-04

Sources: Air Consulting Engineering, Inc., 2001; Golder, 2003

APPENDIX E

CALPUFF MODEL DESCRIPTION AND MODEL ASSUMPTIONS

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

E.1 INTRODUCTION

As part of the new source review requirements under Prevention of Significant Deterioration (PSD) regulations, new major sources or major modifications to those sources are required to address air quality impacts at PSD Class I areas. As part of the PSD analysis report submitted to the Florida Department of Environmental Protection (DEP), the air quality impacts due to the potential emissions of the proposed Project at the Osceola Farms Mill are required to be addressed at the PSD Class I area of the Everglades National Park (NP). The Everglades NP is located approximately 120 km south of the facility site and is the only PSD Class I area within 200 km of the facility.

The evaluation of air quality impacts are not only concerned with determining compliance with PSD Class I increments but also assessing a source's impact on Air Quality Related Values (AQRVs), such as regional haze. Further, compliance with PSD Class I increments can be evaluated by determining if the source's impacts are less than the proposed U.S. Environmental Protection Agency (EPA) Class I significant impact levels. The significant impact levels are threshold levels that are used to determine the type of air impact analyses needed for the facility. 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 with Class I increments.

Currently there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and Federal Land Managers (FLM) of Class I areas who are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in two documents:

- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report.
- *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report,* USFS, NPS, USFWS (12/00), referred to as the FLAG document.

For the proposed project, air quality analyses were performed that assess the Project's impacts in the PSD Class I area of the Everglades NP using the refined modeling approach from the IWAQM Phase 2 report for:

- Significant impact analysis
- SO_2 PSD Class I increment analysis; and
- Regional haze analysis

The refined analysis approach was used instead of the screening analysis approach since the air quality impacts are based on generally more realistic assumptions, include more detailed meteorological data, and are estimated at locations at the Class I area.

E.2 GENERAL AIR MODELING APPROACH

The general modeling approach was based on using the long-range transport model, California Puff model (CALPUFF, Version 5.5). At distances beyond 50 km, the ISCST3 (ISC-PRIME) model is considered to over-predict air quality impacts, because it is a steady-state model. At those distances, the CALPUFF model is recommended for use. Recently, the FLM have requested that air quality impacts, such as for regional haze, for a source located more than 50 km from a Class I area be predicted using the CALPUFF model. The Florida DEP has also recommended that the CALPUFF model be used to assess if the source has a significant impact at a Class I area located beyond 50 km from the source. As a result, a significant impact and regional haze analyses were performed using the CALPUFF model to assess the facility's impacts at the Everglades NP.

The methods and assumptions used in the CALPUFF model were based on the latest recommendations for a refined analysis as presented in the IWAQM Phase 2 Summary Report and the FLAG documents.

A regional haze analysis was performed to determine the affect that the facility's emissions will have on background regional haze levels at the Everglades NP. In the regional haze analysis, the change in visual range, as calculated by a deciview change, was estimated for the facility in accordance with the IWAQM recommendations. Based on those recommendations, the CALPUFF model is used to predict the maximum 24-hour average sulfate (SO_4), nitrate (NO_3), and fine particulate (PM_{10}) concentrations as well as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium nitrate (NH_4NO_3) concentrations. The change in visibility due to a source, estimated as a percentage, is then calculated based on the change from background data.

The following sections present the methods and assumptions used to assess the refined significant impact and regional haze analyses performed for the Proposed Project. The results of these analyses are presented in Sections 6.0 and 7.0 of the PSD report.

E.3 MODEL SELECTION AND SETTINGS

The California Puff (CALPUFF, version 5.5) air modeling system was used to model to assess the Proposed Project's impacts at the PSD Class I area for comparison to the PSD Class I significant impact levels and to the regional haze visibility criteria. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALPUFF meteorological and geophysical data preprocessor (CALMET, Version 5.2), 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 FORTRAN 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 and FLAG reports.

E.3.1 CALPUFF MODEL APPROACHES AND SETTINGS

The IWAQM has recommended approaches for performing a Phase 2 refined modeling analyses that are presented in Table E-1. These approaches involve use of meteorological data, selection of receptors and dispersion conditions, and processing of model output.

The specific settings used in the CALPUFF model are presented in Table E-2.

E.3.2 EMISSION INVENTORY AND BUILDING WAKE EFFECTS

The CALPUFF model included the facility's emission, stack, and operating data as well as building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 95086, and were included in the CALPUFF model input. The PSD Analysis Report presents a listing of the facility's emissions and structures included in the analysis.

E.4 RECEPTOR LOCATIONS

For the refined analyses, pollutant concentrations were predicted in an array of 126 discrete receptors located at the Everglades NP area. These receptors are the same as those used in the PSD Class I analysis performed for the PSD Analysis Report.

E.5 METEOROLOGICAL DATA

E.5.1 REFINED ANALYSIS

CALMET was used to develop the gridded parameter fields required for the refined modeling analyses. The follow sections discuss the specific data used and processed in the CALMET model.

E.5.2 CALMET SETTINGS

The CALMET settings contained in Table E-3 were used for the refined modeling analysis. With the exception of hourly precipitation data files, all input data files needed for CALMET were developed by the FDEP staff.

E.5.3 MODELING DOMAIN

A rectangular modeling domain extending 450 km in the east-west (x) direction and 470 km in the north-south (y) direction was used for the refined modeling analysis. The southwest corner of the domain is the origin and is located at 23.8 degrees north latitude and 83.5 degrees west longitude. This location is in the Gulf of Mexico approximately 110 km west of Venice, Florida. For the processing of meteorological and geophysical data, the domain contains 90 grid cells in the x-direction and 94 grid cells in the y-direction. The domain grid resolution is 4 km. The air modeling analysis was performed in the UTM coordinate system.

E.5.4 MESOSCALE MODEL – GENERATION 4 AND 5 (MM4/MM5) DATA

Pennsylvania State University in conjunction with the NCAR Assessment Laboratory developed the MM4 and MM5 datasets, prognostic wind fields or "guess" fields, for the United States. The hourly meteorological variables used to create these datasets (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and have been developed for the MM4 data for 1990 and the MM5 data for 1992, and 1996. The analysis used the MM4 and MM5 data to initialize the CALMET wind field. The MM4 and MM5 data have horizontal spacing of 80 and 36 km, respectively, and are used to simulate atmospheric variables within the modeling domain.

The MM4 subset domain was provided by FDEP and consisted of a 7 x 7- cell rectangle, with 80 km grid resolution, extending from the MM4 grid points (50,6) to (57,13). These data were processed to create a MM4.DAT file, for input to the CALMET model. The MM5 subset domain was provided by the National Park Service and was processed in a similar manner as the MM4 data.

The MM4 and MM5 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.

E.5.5 SURFACE DATA STATIONS AND PROCESSING

The surface station data processed for the CALPUFF analyses consisted of data from eight NWS stations or Federal Aviation Administration (FAA) Flight Service stations for Orlando, Fort Myers, Daytona Beach, Vero Beach, Key West, Miami, Tampa, and West Palm Beach. A summary of the surface station information and locations are presented in Table E-4. The surface station parameters include 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 surface station data were processed by FDEP into a SURF.DAT file format for CALMET input.

Because the modeling domain extends largely over water, C-Man station data from Venice, Sombrero Key, and Lake Worth was obtained. These data were processed by Florida DEP into an over-water surface station format (i.e., SEA*.DAT) for input to CALMET. The over-water station data include wind direction, wind speed and air temperature.

E.5.6 UPPER AIR DATA STATIONS AND PROCESSING

The analysis included three upper air NWS stations located in Ruskin, Key West, and West Palm Beach. Data for each station were obtained from the Florida DEP in a format for CALMET input. The data and locations for the upper air stations are presented in Table E-4.

E.5.7 PRECIPITATION DATA STATIONS AND PROCESSING

Precipitation data were processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation-recording stations located within the latitude and longitudinal limits of the modeling domain. Data for 23 stations were obtained in NCDC TD-3240 variable format and converted into a fixed-length format. The utility programs PXTRACT and PMERGE were then used to process the data into the format for the PRECIP.DAT file that is used by CALMET. A listing of the precipitation stations used for the modeling analysis is presented in Table E-5.

E.5.8 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 the U.S. Geographical Survey (USGS) internet website. The DEM data was extracted for the modeling domain grid using the utility program TERREL. Land-use data were also extracted from 1-degree USGS files and processed using utility programs CTGCOMP and CTGPROC. Both the terrain and land use files were combined into a GEO.DAT file for input to CALMET with the MAKEGEO utility program.

Table E-1. Refined Modeling Analyses Recommendations [a]

Model Input/Output	Description
Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; obtain regulatory concurrence on coverage.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition. 3. Define background values for ozone and ammonia for area.
Processing	1. For PSD increments: use highest, second highest 3-hour and 24-hour average SO_2 concentrations; highest, second highest 24-hour average PM_{10} concentrations; and highest annual average SO_2, PM_{10} and NO_x concentrations. 2. For haze: process, on a 24-hour basis, compute the source extinction from the maximum increase in emissions of SO_2, NO_x and PM_{10}; compute the daily relative humidity factor [f(RH)], provided from an external disk file; and compute the maximum percent change in extinction using the FLM supplied background extinction data in the FLAG document. 3. For significant impact analysis: use highest annual and highest short-term averaging time concentrations for SO_2, PM_{10} and NO_x.

[a] IWAQM Phase II report (December, 1998) and FLAG document (December, 2000)

Table E-2. CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10}
Chemical Transformation	MESOPUFF II scheme, hourly ozone data
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, PM_{10}, SO_2, and NO_x; process for visibility change using Method 2 and FLAG background extinctions
Model Processing	For haze: highest predicted 24-hour extinction change (%) for the year For deposition: annual average deposition rate For significant impact analysis: highest predicted annual and highest short-term averaging time concentrations for SO_2, NO_x, and PM_{10}.
Background Values	Ozone: 80 ppb; Ammonia: 1 ppb

[a] Recommended values by the Florida DEP.

Table E-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
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	MM4 data, 80 km resolution, 7 x 7 grid, used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input

Table E-4. Surface and Upper Air Stations Used in the CALPUFF Analysis

Station Name	Station Symbol	WBAN Number	UTM Coordinates Easting (km)	Northing (km)	Zone	Anemometer Height (m)
Surface Stations						
Tampa	TPA	12842	349.20	3094.25	17	6.7
Daytona Beach	DAB	12834	495.14	3228.05	17	9.1
Orlando	ORL	12815	468.96	3146.88	17	10.1
Vero Beach	VER	12843	557.52	3058.36	17	6.7
Fort Myers	FMY	12835	413.65	2940.38	17	6.1
Miami	MIA	12839	566.82	2857.20	17	7.0
Key West	EYW	12836	424.03	2715.14	17	18.3
West Palm Beach	PBI	12844	587.87	2951.43	17	10.1
Upper Air Stations						
Ruskin	TBW	12842	349.20	3094.28	17	NA
West Palm Beach	PBI	12844	587.87	2951.42	17	NA
Key West	EYW	12836	424.03	2715.14	17	NA

Table E-5. Hourly Precipitation Stations Used in the CALPUFF Analysis

Station Name	Station Number	UTM Coordinate Easting (km)	UTM Coordinate Northing (km)	Zone
Belle Glade HRCN GT 4	80616	528.19	2953.03	17
Boca Raton	80845	588.75	2916.52	17
Canal Point Gate 5	81271	536.43	2971.51	17
Clewiston US Engineers	81654	546.19	2912.73	17
Fort Myers FAA/AP	83186	413.99	2940.71	17
Homestead Exp Stn	84091	550.26	2820.21	17
Key West Intl AP	84570	423.67	2715.51	17
Miami WSCMO Airport	85663	570.20	2856.17	17
Moore Haven Lock 1	85895	491.61	2967.80	17
North New River Canal #	86323	546.58	2912.48	17
Ortona Lock 2	86657	470.17	2962.27	17
Parrish	86880	366.99	3054.39	17
Pennsuco 5 WNW	86988	554.70	2867.81	17
Port Mayaca S 1 Canal	87293	538.04	2984.44	17
St Lucie New Lock 1	87859	571.04	2999.35	17
St Petersburg	87886	339.61	3071.99	17
Tamiami Trail 40 Mi BEN	88780	517.64	2849.04	17
Tampa WSCMO AP	88788	348.48	3093.67	17
Trail Glade Ranges	89010	551.57	2849.99	17
Venice	89176	357.59	2998.18	17
Venus	89184	467.27	3001.22	17
Vero Beach 4 W	89219	554.27	3056.50	17
West Palm Beach Int AP	89525	589.61	2951.63	17

APPENDIX F

DETAILED NO_x EMISSION SOURCE DATA USED IN MODELING ANALYSES

Table F-1 Summary of NO_x Sources Included in the Air Modeling Analysis for Osceola Farms Mill

AIRS Number	Facility	Units	EU #	ISCST3 ID Name	Relative Location[c] X (m)	Relative Location[c] Y (m)	Stack Parameters Height (m)	Stack Parameters Diameter (m)	Stack Parameters Temper. (K)	Stack Parameters Velocity (m/s)	Emission Rate TPY	Emission Rate g/s	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in Class II
0990019	OSCEOLA FARMS PSD Baseline[a]														
		BOILER #2 PSD Baseline	2	OSBLR2B	164.6	-37.0	22.00	1.52	342.0	14.22	-37.6	-1.88	EXP	No	Yes
		BOILER #3 PSD Baseline	3	OSBLR3B	166.3	-27.7	22.00	1.93	342.0	11.23	-16.9	-0.84	EXP	No	Yes
		BOILER #4 PSD Baseline	4	OSBLR4B	154.6	-10.5	22.00	1.83	342.0	13.35	-30.4	-1.52	EXP	No	Yes
		BOILER #5 PSD Baseline	5	OSBLR5B	164.6	14.7	22.00	1.52	342.0	12.02	-38.3	-4.83	EXP	No	Yes
		BOILER #6 PSD Baseline	6	OSBLR6B	132.3	-25.2	27.43	1.93	341.5	17.07	-39.9	-2.00	EXP	No	Yes
0990061	U.S. Sugar, Bryant[a]	BOILERS #s 1, 2, & 3		USBRY123	-6,900	1,820	19.81	1.64	342.0	36.40	1,060.2	65.49	NO	Yes	No
		BOILER #5	5	USBRY5	-6,900	1,820	45.70	2.90	345.4	14.80	384.2	20.37	NO	Yes	No
		DIESEL ELECTRIC GENERATOR #1	7	USBRY7	-6,900	1,820	8.53	0.37	519.3	12.19	262.0	7.54	NO	Yes	No
		DIESEL ELECTRIC GENERATOR #2	8	USBRY8	-6,900	1,820	8.53	0.37	519.3	12.80	278.0	7.99	NO	Yes	No
0990026	SUGAR CANE GROWERS[a]	BOILER #1 & #2		SUGCN12	-9,800	-14,000	45.72	1.87	339.0	21.75	1,096.8	37.88	CON	Yes	Yes
		BOILER #3	3	SUGCN3	-9,800	-14,000	27.43	1.52	339.0	22.25	227.2	12.96	CON	Yes	Yes
		BOILER #4	4	SUGCN4	-9,800	-14,000	54.90	2.44	339.0	21.73	938.5	32.41	CON	Yes	Yes
		BOILER #5	5	SUGCN5	-9,800	-14,000	45.72	2.30	339.0	15.94	720.8	24.90	CON	Yes	Yes
		BOILER # 8	8	SUGCN8	-9,800	-14,000	47.24	2.90	339.0	13.62	449.0	15.50	CON	Yes	Yes
		BOILER #1 & #2 PSD Baseline		SUGCN12B	-9,800	-14,000	24.40	1.40	344.0	11.40	-68.0	-3.40	EXP	No	Yes
		BOILER #3 PSD Baseline	3	SUGCN3B	-9,800	-14,000	24.40	1.60	344.0	15.60	-41.6	-2.08	EXP	No	Yes
		BOILER #4 PSD Baseline	4	SUGCN4B	-9,800	-14,000	25.90	1.63	344.0	11.20	-77.7	-3.88	EXP	No	Yes
		BOILER #5 PSD Baseline	5	SUGCN5B	-9,800	-14,000	24.40	1.40	344.0	15.20	-51.8	-2.59	EXP	No	Yes
		BOILER #8 PSD Baseline	8	SUGCN8B	-9,800	-14,000	47.24	2.90	339.0	13.62	-78.5	-2.26	EXP	No	Yes
0990594	El Paso Belle Glade Generating Station														
		Combined Cycle CT, CC-1	1	EPBGCT1	-11,200	-13,200	41.15	5.79	359.3	18.63	71.7	2.06	CON	Yes	Yes
		2 Simple Cycle CTs, SC-1 and SC-2	23	EPBGSC23	-11,200	-13,200	41.15	5.79	862.0	44.79	292.8	8.43	CON	Yes	Yes
0990021	United Technologies Corporation/Pratt& Whitney														
		Air compressor/heater (ACHR-2-B2); slave jet engine	1	UTECH1	17,300	8,700	15.24	0.91	810.9	143.73	572.3	16.48	CON	Yes	Yes
		Boiler (BO-12-E6) w/heat input of 42 mmBTUH in Test Area E	16	UTECH16	17,300	8,700	4.57	0.76	533.0	6.92	26.3	0.76	NO	Yes	No
		2 boilers (BO-1-MBH,BO-2-BMH); 54 MMBTUH each	22	UTECH22	17,300	8,700	20.12	2.32	671.9	10.19	63.7	1.83	CON	Yes	Yes
		Two furnaces (FU-3-MHT, FU-4-MHT), 6 MMBTUH each	40	UTECH40	17,300	8,700	14.90	1.20	298.2	0.04	5.1	0.15	CON	Yes	Yes
		Water evaporator (EV-1-MW) w/heat input of 0.2 MMBTUH	45	UTECH45	17,300	8,700	3.70	0.20	298.2	2.60	0.1	0.0024	CON	Yes	Yes
		Miscellaneous air and fuel heaters fired with natural gas	59	UTECH59	17,300	8,700	6.10	0.50	533.2	4.90	31.8	0.91	CON	Yes	Yes
		Boiler (BO-14-E8) w/heat input of 7 MMBTUH	66	UTECH66	17,300	8,700	7.32	0.41	513.6	33.17	4.5	0.13	CON	Yes	Yes
		Boiler (BO-3-MDL) w/heat input of 1 MMBTUH	67	UTECH67	17,300	8,700	7.32	0.30	513.6	0.32	0.6	0.017	CON	Yes	Yes
		Emergency electrical generating facility	68	UTECH68	17,300	8,700	3.70	0.20	922.0	151.40	233.5	6.72	NO	Yes	No
		Ten existing jet engine test stands located in Test Area	69	UTECH69	17,300	8,700	5.50	3.70	422.0	0.08	813.6	23.43	NO	Yes	No
		A-10 Test Stand		UTECHA10	17,300	8,700	5.79	4.17	410.9	106.68	39.0	1.12	NO	Yes	No
0850102	Bechtel Indiantown	Pulverized Coal Main Boiler	1	INDTWN1	900	24,200	150.88	4.88	333.2	30.50	2,549.0	73.33	CON	Yes	Yes
		(2) Auxiliary Boilers	3	INDTWN3	900	24,200	64.01	1.52	449.8	26.70	34.0	9.02	CON	Yes	Yes
0990016	ATLANTIC SUGAR ASSOCIATION[a]	BOILER #1	1	ATLSUG1	8,200	-22,100	27.43	1.89	344.3	16.82	550.4	31.75	NO	Yes	No
		BOILER #2	2	ATLSUG2	8,200	-22,100	27.43	1.89	344.3	12.50	550.4	31.75	NO	Yes	No
		BOILER #3	3	ATLSUG3	8,200	-22,100	18.29	1.83	338.7	16.15	512.5	14.74	NO	Yes	No
		BOILER # 4	4	ATLSUG4	8,200	-22,100	27.43	1.83	338.7	16.15	542.0	15.59	NO	Yes	No
		BOILER # 5[b]	5	ATLSUG5	8,200	-22,100	27.43	1.68	338.7	19.20	69.4	2.00	CON	Yes	Yes
		BOILER # 5 PSD Baseline	5	ATLSUG5B	8,200	-22,100	27.40	1.68	339.0	15.70	-14.8	-0.74	EXP	No	Yes
0850001	FP&L Martin	Units 1 & 2		MART12	-1,600	25,600	152.10	7.99	420.9	21.03	22,732.0	653.94	NO	Yes	No
		Units 3 & 4		MART34	-1,600	25,600	64.92	6.10	410.9	18.90	12,432.0	89.21	CON	Yes	Yes
		2 Simple Cycle CTs		MARTCTs	-1,600	25,600	18.30	6.71	853.2	37.63	325.4	93.39	CON	Yes	Yes
		Unit 8		MART8	-1,600	25,600	36.60	5.79	420.0	22.40	677.6	19.51	CON	Yes	Yes

Table F-1 Summary of NO_x Sources Included in the Air Modeling Analysis for Osceola Farms Mill

AIRS			EU	ISCST3	Relative Location [c]		Stack Parameters				Emission Rate		PSD Source?	Modeled in	
Number	Facility	Units	#	ID Name	X (m)	Y (m)	Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	TPY	g/s	(EXP/CON)	AAQS	Class II
0990005	OKEELANTA [a]	BOILER #4 PSD Baseline	3	OKBLR4B	-19,700	-29,900	22.90	2.29	333.0	7.36	-27.3	-1.36	EXP	No	Yes
		BOILER #5 PSD Baseline	4	OKBLR5B	-19,700	-29,900	22.90	2.29	333.0	12.07	-37.8	-1.89	EXP	No	Yes
		BOILER #6 PSD Baseline	5	OKBLR6B	-19,700	-29,900	22.90	2.29	334.0	8.74	-31.9	-1.59	EXP	No	Yes
		BOILER # 10 PSD Baseline	9	OKBLR10B	-19,700	-29,900	22.90	2.29	334.0	10.35	-36.0	-1.80	EXP	No	Yes
		BOILER # 11 PSD Baseline	10	OKBLR11B	-19,700	-29,900	22.90	2.29	342.0	9.89	-46.0	-2.30	EXP	No	Yes
		BOILER # 12 PSD Baseline	12	OKBLR12B	-19,700	-29,900	22.90	2.29	330.0	8.20	-57.7	-2.88	EXP	No	Yes
		BOILER # 14 PSD Baseline	14	OKBLR14B	-19,700	-29,900	22.90	2.29	333.0	8.30	-63.6	-3.18	EXP	No	Yes
		BOILER # 15 PSD Baseline	15	OKBLR15B	-19,700	-29,900	22.90	2.29	332.0	10.20	-50.5	-2.52	EXP	No	Yes
		BOILER # 16	16	OKBLR16	-19,700	-29,900	22.86	1.52	483.2	22.86	113.8	3.28	CON	Yes	Yes
0990332	New Hope Power Partnership	COGEN Units 1, 2, & 3 [b]	123	OKCOGEN	-20,610	-27,290	60.66	3.05	450.9	19.39	862.5	24.8	CON	Yes	Yes
0510001	EVERGLADES SUGAR	MAIN BOILER [b]	2	EVERGLAD	-35,100	-13,100	21.95	1.07	477.6	10.06	168.0	4.82	NO	Yes	No
510003	US Sugar - Clewiston														
		PSD Baseline (Crop season only) [a]													
		Unit 1 PSD Baseline		BRL1B	-38,600	-10,400	23.1	1.86	344.0	30.20	-93.7	-6.27	EXP	No	Yes
		Unit 2 PSD Baseline		BLR2B	-38,600	-10,400	23.1	1.86	343.0	35.70	-94.0	-6.29	EXP	No	Yes
		Unit 3 PSD Baseline		BLR3B	-38,600	-10,400	27.4	2.29	342.0	14.70	-45.1	-3.03	EXP	No	Yes
		Units 4 PSD Baseline		BLR4B	-38,600	-10,400	45.7	2.51	344.3	25.40	-127.9	-8.76	EXP	No	Yes
		Units 5 PSD Baseline		BLR5B	-38,600	-10,400	23.1	1.86	494.0	44.30	-20.9	-1.54	EXP	No	Yes
		Units 6 PSD Baseline		BLR6B	-38,600	-10,400	23.1	1.86	494.0	44.30	-18.0	-1.34	EXP	No	Yes
		Off-crop season future [d]													
		Unit 1		USSBRL1F	-38,600	-10,400	65.0	2.44	347.0	19.20	142.4	4.10	CON	Yes	Yes
		Unit 2		USSBLR2F	-38,600	-10,400	65.0	2.44	338.7	17.32	142.4	4.10	CON	Yes	Yes
		Unit 4		USSBLR4F	-38,600	-10,400	45.7	2.51	344.3	6.78	0.0	0.00	CON	Yes	Yes
		Unit 7		USSBLR7F	-38,600	-10,400	68.6	2.59	405.4	24.05	332.1	9.56	CON	Yes	Yes
		On-crop season future [a]													
		Unit 1		USSBRL1N	-38,600	-10,400	65.0	2.44	347.0	17.70	313.7	9.03	CON	Yes	Yes
		Unit 2		USSBLR2N	-38,600	-10,400	65.0	2.44	338.7	16.19	288.7	8.31	CON	Yes	Yes
		Unit 4		USSBLR4N	-38,600	-10,400	45.7	2.51	344.3	6.20	378.2	10.89	CON	Yes	Yes
		Unit 7		USSBLR7N	-38,600	-10,400	68.6	2.59	405.4	23.60	476.0	13.71	CON	Yes	Yes
		Unit 8		USSBLN8	-38,600	-10,400	60.7	3.96	439.0	15.31	609.0	17.54	CON	Yes	Yes
		Granular Carbon Furnace		USSS12	-38,600	-10,400	9.1	0.61	344.3	6.90	13.1	0.38	CON	Yes	Yes
0990234	Solid Waste Authority of PBC														
		412.5MMBTU/HR RDF BOILER NO.1 (324,000 lb/hr STEAM)	1	SWAPB1	39,790	-6,040	76.2	2.04	505.2	24.90	867.2	24.98	NO	Yes	No
		412.5MMBTU/HR RDF BOILER NO.2 (324,000 lb./hr. steam)	2	SWAPB2	39,790	-6,040	76.2	2.04	505.2	24.90	867.2	24.98	NO	Yes	No
		Landfill Gas Coll Sys class I	3	SWAPB3	39,790	-6,040	7.0	0.21	1033.0	24.44	15.8	0.46	NO	Yes	No
		Landfill Gas Coll Sys class III	4	SWAPB4	39,790	-6,040	7.0	0.15	1033.0	46.57	15.8	0.46	NO	Yes	No
0990042	FP&L Riviera [c]	Units 3 & 4		RIVU34	49,500	-6,700	90.83	4.88	401.5	18.90	16,565.2	476.53	NO	Yes	No
0990045	Lake Worth Utilities [c]	Diesel Peking Units # 1-5		LAKWTH15	48,100	-23,600	5.18	0.56	625.9	37.09	2,184.6	62.87	NO	Yes	No
		GAS TURBINE # 1	6	LAKWTH6	48,100	-23,600	14.02	4.88	720.4	24.84	1,715.0	49.39	NO	Yes	No
		STEAM GENERATING #1	7	LAKWTH7	48,100	-23,600	18.29	1.52	422.0	10.52	0.0	0.00	NO	No	No
		STEAM GENERATOR #3	9	LAKWTH8	48,100	-23,600	34.44	2.13	418.2	15.67	712.0	20.54	NO	Yes	No
		STEAM GENERATOR #4	10	LAKWTH9	48,100	-23,600	35.05	2.29	418.2	17.01	0.0	0.00	NO	No	No
		COMBINED CYCLE UNIT (GT-2/S-5)	11	LAKWTH10	48,100	-23,600	22.86	3.05	481.0	27.80	1,252.0	36.04	NO	Yes	No
1110003	Ft. Pierce Utilities Authority [c]	2.75 MW West Diesel #1	1	FTPRC1	21,420	69,050	7.01	0.91	783.0	11.89	392.4	11.30	NO	Yes	No

Table F-1 Summary of NO_x Sources Included in the Air Modeling Analysis for Osceola Farms Mill

AIRS Number	Facility	Units	EU #	ISCST3 ID Name	Relative Location[c] X (m)	Y (m)	Stack Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate TPY	g/s	PSD Source? (EXP/CON)	Modeled in AAQS	Class II
		2.75 MW East Diesel #2	2	FTPRC2	21,420	69,050	7.01	0.91	783.0	11.89	392.4	11.30	NO	Yes	No
		23.4 MW Combined Cycle Gas Turbine with 8.2 MW HRSG-Unit # 9	3	FTPRC3	21,420	69,050	20.73	3.41	491.9	18.23	592.7	17.07	NO	Yes	No
		16.5 MW Boiler Unit #6	4	FTPRC4	21,420	69,050	45.11	1.52	435.8	10.97	5.7	0.16	NO	Yes	No
		33.0 MW Boiler Unit #7 (Phase II Acid Rain Unit)	7	FTPRC7	21,420	69,050	44.81	2.16	426.3	18.62	457.1	13.16	NO	Yes	No
		56.1 MW Boiler Unit #8 (Phase II Acid Rain Unit)	8	FTPRC8	21,420	69,050	45.72	2.44	440.8	25.48	167.2	4.82	NO	Yes	No
		General Purpose Internal Combustion Engines	10	FTPRC10	21,420	69,050	45.72	2.44	440.8	25.48	83.6	2.41	NO	Yes	No
0112120	Wheelabrator North Broward[c]	UNIT #1;807 TPD MSW INCINERATOR	1	WHEELN1	39,200	-59,700	58.50	3.96	381.0	18.01	686.8	209.33	NO	Yes	No
		UNIT #2 807 TPD MSW INCINERATOR	2	WHEELN2	39,200	-59,700	58.50	3.96	381.0	18.01	686.8	209.33	NO	Yes	No
		UNIT #3 807 TPD MSW INCINERATOR	3	WHEELN3	39,200	-59,700	58.50	3.96	381.0	18.01	686.8	209.33	NO	Yes	No
0610029	City of Vero Beach[c]	Fossil Fuel Steam Generator Unit No.1	1	VERO1	16,700	89,200	60.96	1.07	437.0	32.42	472.0	13.59	NO	Yes	No
		Fossil Fuel Steam Generator Unit No.2	2	VERO2	16,700	89,200	60.96	1.07	434.3	37.57	580.0	16.70	NO	Yes	No
		Fossil Fuel Steam Generator Unit 3 (Phase II Acid Rain Unit)	3	VERO3	16,700	89,200	60.96	1.83	440.4	20.91	975.3	28.09	NO	Yes	No
		Fossil Fuel Steam Generator Unit 4 (Phase II Acid Rain Unit)	4	VERO4	16,700	89,200	60.96	2.13	425.4	23.68	1,800.2	51.85	NO	Yes	No
		Combined Cycle Gas Turbine Unit 5 (Phase II Acid Rain Unit)	5	VERO5	16,700	89,200	19.39	37.58	416.3	19.39	487.4	14.04	CON	Yes	Yes
0112119	South Broward RRF[c]	UNIT #1, 863 TPD MSW INCINERATOR	1	SBROW1	34,900	-84,000	59.44	3.96	380.8	18.01	793.7	22.86	CON	Yes	Yes
		UNIT #2, 863 TPD MSW INCINERATOR	2	SBROW2	34,900	-84,000	59.44	3.96	380.8	18.01	793.7	22.86	CON	Yes	Yes
		UNIT #3, 863 TPD MSW INCINERATOR	3	SBROW3	34,900	-84,000	59.44	3.96	380.8	18.01	793.7	22.86	CON	Yes	Yes
0110037	Florida Power & Light--Lauderdale[c]	Bank of 12 Combustion Turbines (Nos. 1 to 12)	3	FPLCT3	35,400	-84,000	13.72	2.37	733.0	114.30	5,161.4	148.65	NO	Yes	No
		Bank of 12 Combustion Turbines (No. 13 to 24)	15	FPLCT15	35,400	-84,000	13.41	4.75	733.0	28.44	5,161.4	148.65	NO	Yes	No
		CCCT with HRSG (CT 4A) (Phase II Acid Rain Unit)	35	FPLCT35	35,400	-84,000	45.72	5.49	438.6	14.60	3,065.0	88.27	CON	Yes	Yes
		CCCT with HRSG (CT 4B) (Phase II Acid Rain Unit)	36	FPLCT36	35,400	-84,000	45.72	5.49	438.6	14.60	3,065.0	88.27	CON	Yes	Yes
		CCCT with HRSG (CT 5A) (Phase II Acid Rain Unit)	37	FPLCT37	35,400	-84,000	45.72	5.49	438.6	14.60	1,639.0	47.20	CON	Yes	Yes
		CCCT with HRSG (CT 5B) (Phase II Acid Rain Unit)	38	FPLCT38	35,400	-84,000	45.72	5.49	438.6	14.60	3,065.0	88.27	CON	Yes	Yes
		Units 4 & 5 Baseline		FPL45B	35,400	-84,000	46.00	4.27	422.0	14.63	0.0	0.00	EXP	No	No
0110036	FP&L--Port Everglades[c]	232 NW FFSG #1 w/Low Excess Air Burners&Multi-Cyclones	1	FPPE1	42,700	-82,000	104.50	4.27	415.9	26.70	5,729.0	165.00	NO	Yes	No
		232 NW FFSG #2 w/Low Excess Air Burners&Multi-Cyclones	2	FPPE2	42,700	-82,000	104.50	4.27	415.9	26.70	5,729.0	165.00	NO	Yes	No
		401 NW FFSG #3 w/Low Excess Air Burners&Multi-Cyclones	3	FPPE3	42,700	-82,000	104.50	5.52	414.8	23.90	16,609.0	478.34	NO	Yes	No
		401 NW FFSG #4 w/Low Excess Air Burners&Multi-Cyclones	4	FPPE4	42,700	-82,000	104.50	5.52	414.8	23.90	16,609.0	478.34	NO	Yes	No
		Gas Turbines Electric Generating Unit #1-12	5	FPPE5	42,700	-82,000	13.41	4.75	683.0	10.67	6,633.0	191.03	NO	Yes	No
0550018	Tampa Electric Co.--PHILLIPS[c]	SLOW SPEED DIESEL ELECTRIC GENERATOR UNIT 1 P	1	TECO1	-80,400	68,100	45.72	1.83	441.3	24.08	2,504.5	72.13	NO	Yes	No
		SLOW SPEED DIESEL ELECTRIC GENERATOR UNIT 2 P	2	TECO2	-80,400	68,100	45.72	1.83	449.7	24.08	2,504.5	72.13	NO	Yes	No
		BOILER CLEAVER BROOKS CB200X-250 HEAT INPUT 10.46 MMBTU/HR	4	TECO4	-80,400	68,100	18.90	0.67	ND	ND	6.5	0.19	NO	No	No
0250020	Tarmac-Pennsuco Cement[c]	KILN #2 (Restart 1990)	4	TARM4	18,200	-105,600	60.96	2.44	421.9	9.10	867.2	24.98	CON	Yes	Yes
		KILN #3	6	TARM6	18,200	-105,600	60.96	4.57	450.0	11.04	2,594.0	74.71	CON	Yes	Yes
		125 ton per hour slag dryer	20	TARM20	18,200	-105,600	9.14	1.22	421.9	17.98	12.8	0.37	CON	Yes	Yes
		KILN #3 Baseline		TARM3B	18,200	-105,600	60.96	4.57	450.0	11.04	-2,112.3	-60.83	EXP	No	Yes
0250348	Miami-Dade RRF/Montenay[c]	Boilers #1-4	14	MDADE14	19,130	-109,680	76.20	3.66	405.4	15.86	2,459.6	70.84	CON	Yes	Yes
		Boilers #1-4 Baseline	14	MDADE14B	19,130	-109,680	45.70	2.74	461.0	30.34	749.0	-21.57	EXP	No	Yes
0710002	FP&L Fort Myers[c]	Gas Turbines 1 - 12		FMYGT112	-122,600	-14,400	9.75	4.42	797.0	57.73	31,272.0	900.00	NO	Yes	No
		HRSGs 1 - 6		FMYHR16	-122,600	-14,400	38.10	5.79	377.6	14.20	1,708.2	49.14	CON	Yes	Yes
		CT1 - 2		FMCT1_2	-122,600	-14,400	24.40	6.25	852.0	39.08	293.1	84.12	CON	Yes	Yes
		Unit No. 1 PSD Baseline		FMU1B	-122,600	-14,400	91.74	2.90	422.0	29.90	-910.0	-26.21	EXP	No	Yes
		Unit No. 2 PSD Baseline		FMU2B	-122,600	-14,400	121.31	5.52	408.0	19.20	-4,140.0	-119.23	EXP	No	Yes

[a] Facilities or sources that operate only during the October 1 through April 31 crop season.

Table F-1 Summary of NO_x Sources Included in the Air Modeling Analysis for Osceola Farms Mill

AIRS			EU	ISCST3	Relative Location [e]		Stack Parameters				Emission Rate		PSD Source?	Modeled in	
					X	Y	Height	Diameter	Temper.	Velocity					
Number	Facility	Units	#	ID Name	(m)	(m)	(m)	(m)	(K)	(m/s)	TPY	g/s	(EXP/CON)	AAQS	Class II

[b] Sugar mill sources that operate all year.

[c] Large source (>1,000 TPY) outside the screening area that are included in the modeling analysis.

[d] Sugar mill sources that operate only during the May 1 through September 30 off-crop season (assumes 150 days).

[e] Location relative to the midpoint of the cogen Boilers Nos. 1 and 2 stack locations.

Note: EXP = PSD expanding source.
CON = PSD consuming source.
NO = Source does not affect PSD increment.
ND = No data available.

APPENDIX G

BPIP INPUT AND OUTPUT WITH SOURCE AND BUILDING LOCATIONS

```
'BPIP data for Osceola BASELINE (from PBP) 1988 8/25/04'
'ST'
'METERS' 1.0
'UTMN' 0.00
1
'EXISTING MAIN BLDG' 1 0.0
  21.34
 184.8    15.1
 215.0    15.1
 215.0   -18.5
 226.8   -18.5
 226.8   -32.8
 215.0   -32.8
 215.0   -58.4
 231.0   -58.4
 231.0   -78.5
 159.6   -78.5
 159.6   -58.4
 184.8   -58.4
5
'OSBLR2B'  0.0   22.0  164.6  -37.0
'OSBLR3B'  0.0   22.0  166.3  -27.7
'OSBLR4B'  0.0   22.0  154.6  -10.5
'OSBLR5AB' 0.0   22.0  146.6   14.7
'OSBLR6B'  0.0   27.4  132.3  -25.2
0
```

BPIP (Dated: 95086)

DATE : 8/27/ 4
TIME : 11:33:41
BPIP data for Osceola BASELINE (from PBP) 1988 8/25/04

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BPIP PROCESSING INFORMATION:
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The ST flag has been set for processing for an ISCST2 run.

Inputs entered in METERS will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

UTMP is set to UTMN. The input is assumed to be in a local X-Y coordinate system as opposed to a UTM coordinate system. True North is in the positive Y direction.

Plant north is set to 0.00 degrees with respect to True North.

BPIP data for Osceola BASELINE (from PBP) 1988 8/25/04

PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
OSBLR2B	22.00	0.00	53.35	65.00
OSBLR3B	22.00	0.00	53.35	65.00
OSBLR4B	22.00	0.00	53.35	65.00
OSBLR5AB	22.00	0.00	53.35	65.00
OSBLR6B	27.40	0.00	53.35	65.00

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP Technical Support Document. Determinant 3 may be investigated for additional stack height credit. Final values result after Determinant 3 has been taken into consideration.

** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

BPIP (Dated: 95086)

DATE : 8/27/ 4
TIME : 11:33:41

BPIP data for Osceola BASELINE (from PBP) 1988 8/25/04

BPIP output is in meters

```
SO BUILDHGT OSBLR2B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR2B     73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR2B    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR2B    107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR2B     73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR2B    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR2B    107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSBLR3B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3B     21.34   21.34   21.34   21.34   21.34   21.34
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SO BUILDHGT OSBLR3B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR3B     73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR3B    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR3B    107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR3B     73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR3B    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR3B    107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSBLR4B      0.00    0.00    0.00   21.34   21.34   21.34
SO BUILDHGT OSBLR4B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4B      0.00    0.00    0.00   21.34   21.34   21.34
SO BUILDHGT OSBLR4B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR4B      0.00    0.00    0.00   95.56  101.40  104.16
SO BUILDWID OSBLR4B    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR4B    107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR4B      0.00    0.00    0.00   95.56  101.40  104.16
SO BUILDWID OSBLR4B    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR4B    107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSBLR5AB     0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT OSBLR5AB     0.00   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5AB    21.34   21.34   21.34   21.34   21.34    0.00
SO BUILDHGT OSBLR5AB     0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT OSBLR5AB     0.00   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5AB    21.34   21.34   21.34   21.34   21.34    0.00
SO BUILDWID OSBLR5AB     0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDWID OSBLR5AB     0.00  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5AB   107.31  102.60   94.78   84.07   76.60    0.00
SO BUILDWID OSBLR5AB     0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDWID OSBLR5AB     0.00  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5AB   107.31  102.60   94.78   84.07   76.60    0.00

SO BUILDHGT OSBLR6B      0.00    0.00    0.00    0.00   21.34   21.34
SO BUILDHGT OSBLR6B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR6B     21.34   21.34   21.34   21.34    0.00    0.00
SO BUILDHGT OSBLR6B      0.00    0.00    0.00    0.00   21.34   21.34
SO BUILDHGT OSBLR6B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR6B     21.34   21.34   21.34   21.34    0.00    0.00
SO BUILDWID OSBLR6B      0.00    0.00    0.00    0.00  101.40  104.16
SO BUILDWID OSBLR6B    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR6B    107.31  102.60   94.78   84.07    0.00    0.00
SO BUILDWID OSBLR6B      0.00    0.00    0.00    0.00  101.40  104.16
SO BUILDWID OSBLR6B    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR6B    107.31  102.60   94.78   84.07    0.00    0.00
```

```
'BPIP data for Osceola Blr 4&5 (from PBP) 6/10/03'
'ST'
'METERS' 1.0
'UTMN' 0.00
2
'COGEN BLRS (C-E)' 1 0.0
[illegible]6.58
[illegible]27.3   -25.6
  17.2   -25.6
  17.2   -51.7
 -27.3   -51.7
'EXISTING MAIN BLDG' 1 0.0
12 21.34
 184.8    15.1
 215.0    15.1
 215.0   -18.5
 226.8   -18.5
 226.8   -32.8
 215.0   -32.8
 215.0   -58.4
 231.0   -58.4
 231.0   -78.5
 159.6   -78.5
 159.6   -58.4
 184.8   -58.4
6
'OSBLR2'   0.0   27.4  164.6  -37.0
'OSBLR3'   0.0   27.4  166.3  -27.7
'OSBLR4'   0.0   27.4  154.6  -10.5
'OSBLR5A'  0.0   27.4  146.6    8.4
'OSBLR5B'  0.0   27.4  164.6   14.7
'OSBLR6'   0.0   27.4  132.3  -25.2
0
```

```
                         BPIP (Dated: 95086)
DATE :  6/10/ 3
TIME :  9:56:27
BPIP data for Osceola Blr 4&5 (from PBP) 6/10/03

============================
BPIP PROCESSING INFORMATION:
============================

  The ST flag has been set for processing for an ISCST2 run.

  Inputs entered in METERS     will be converted to meters using
   a conversion factor of    1.0000.  Output will be in meters.

  UTMP is set to UTMN.  The input is assumed to be in a local
   X-Y coordinate system as opposed to a UTM coordinate system.
   True North is in the positive Y direction.

  Plant north is set to   0.00 degrees with respect to True North.


BPIP data for Osceola Blr 4&5 (from PBP) 6/10/03



              PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
                       (Output Units: meters)

                          Stack-Building              Preliminary*
        Stack    Stack    Base Elevation    GEP**     GEP Stack
        Name     Height   Differences       EQN1      Height Value


       OSBLR2     27.40        0.00         81.95        81.95
       OSBLR3     27.40        0.00         85.69        85.69
       OSBLR4     27.40        0.00         91.45        91.45
       OSBLR5A    27.40        0.00         91.45        91.45
       OSBLR5B    27.40        0.00         91.45        91.45
       OSBLR6     27.40        0.00         89.50        89.50

   * Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP
     Technical Support Document.  Determinant 3 may be investigated for
     additional stack height credit.  Final values result after
     Determinant 3 has been taken into consideration.
  ** Results were derived from Equation 1 on page 6 of GEP Technical
     Support Document.  Values have been adjusted for any stack-building
     base elevation differences.

     Note:  Criteria for determining stack heights for modeling emission
     limitations for a source can be found in Table 3.1 of the
     GEP Technical Support Document.




                         BPIP (Dated: 95086)
DATE :  6/10/ 3
TIME :  9:56:27


BPIP data for Osceola Blr 4&5 (from PBP) 6/10/03

 BPIP output is in meters


     SO BUILDHGT OSBLR2     21.34   21.34   21.34   21.34   21.34   21.34
     SO BUILDHGT OSBLR2     21.34   36.58   36.58   36.58   21.34   21.34
     SO BUILDHGT OSBLR2     21.34   21.34   21.34   21.34   21.34   21.34
     SO BUILDHGT OSBLR2     21.34   21.34   21.34   21.34   21.34   21.34
     SO BUILDHGT OSBLR2     21.34   21.34   21.34   21.34   21.34   21.34
     SO BUILDHGT OSBLR2     21.34   21.34   21.34   21.34   21.34   21.34
     SO BUILDWID OSBLR2     73.81   75.43   86.81   95.56  101.40  104.16
     SO BUILDWID OSBLR2    103.76   30.24   26.10   30.24  106.90  108.76
     SO BUILDWID OSBLR2    107.31  102.60   94.78   84.07   76.60   71.40
     SO BUILDWID OSBLR2     73.81   75.43   86.81   95.56  101.40  104.16
     SO BUILDWID OSBLR2    103.76  100.20   93.60  101.80  106.90  108.76
     SO BUILDWID OSBLR2    107.31  102.60   94.78   84.07   76.60   71.40

     SO BUILDHGT OSBLR3     21.34   21.34   21.34   21.34   21.34   21.34
     SO BUILDHGT OSBLR3     21.34   36.58   36.58   21.34   21.34   21.34
     SO BUILDHGT OSBLR3     21.34   21.34   21.34   21.34   21.34   21.34
```

```
SO BUILDHGT OSBLR3     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR3     73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR3    103.76   32.74   26.10  101.80  106.90  108.76
SO BUILDWID OSBLR3    107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR3     73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR3    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR3    107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSBLR4      0.00    0.00    0.00   21.34   21.34   21.34
SO BUILDHGT OSBLR4     36.58   36.58   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4      0.00    0.00    0.00   21.34   21.34   21.34
SO BUILDHGT OSBLR4     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR4      0.00    0.00    0.00   95.56  101.40  104.16
SO BUILDWID OSBLR4     39.75   33.43   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR4    107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR4      0.00    0.00    0.00   95.56  101.40  104.16
SO BUILDWID OSBLR4    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR4    107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSBLR5A     0.00    0.00    0.00    0.00    0.00   36.58
SO BUILDHGT OSBLR5A    36.58   36.58   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5A    21.34   21.34   21.34   21.34   21.34    0.00
SO BUILDHGT OSBLR5A     0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT OSBLR5A    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5A    21.34   21.34   21.34   21.34   21.34    0.00
SO BUILDWID OSBLR5A     0.00    0.00    0.00    0.00    0.00   44.85
SO BUILDWID OSBLR5A    39.75   33.43   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5A   107.31  102.60   94.78   84.07   76.60    0.00
SO BUILDWID OSBLR5A     0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDWID OSBLR5A   103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5A   107.31  102.60   94.78   84.07   76.60    0.00

SO BUILDHGT OSBLR5B    21.34    0.00    0.00    0.00    0.00   36.58
SO BUILDHGT OSBLR5B    36.58   36.58   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5B    21.34    0.00    0.00    0.00    0.00   21.34
SO BUILDHGT OSBLR5B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR5B    73.81    0.00    0.00    0.00    0.00   44.85
SO BUILDWID OSBLR5B    39.75   33.43   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5B   107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR5B    73.81    0.00    0.00    0.00    0.00  104.16
SO BUILDWID OSBLR5B   103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5B   107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSBLR6      0.00    0.00    0.00    0.00   21.34   21.34
SO BUILDHGT OSBLR6     36.58   36.58   36.58   21.34   21.34   21.34
SO BUILDHGT OSBLR6     21.34   21.34   21.34   21.34    0.00    0.00
SO BUILDHGT OSBLR6      0.00    0.00    0.00    0.00   21.34   21.34
SO BUILDHGT OSBLR6     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR6     21.34   21.34   21.34   21.34    0.00    0.00
SO BUILDWID OSBLR6      0.00    0.00    0.00    0.00  101.40  104.16
SO BUILDWID OSBLR6     35.28   33.43   26.10  101.80  106.90  108.76
SO BUILDWID OSBLR6    107.31  102.60   94.78   84.07    0.00    0.00
SO BUILDWID OSBLR6      0.00    0.00    0.00    0.00  101.40  104.16
SO BUILDWID OSBLR6    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR6    107.31  102.60   94.78   84.07    0.00    0.00
```

APPENDIX H

ISCST MODEL SUMMARY AND EXAMPLE INPUT FILES

SIGNIFICANT IMPACT ANALYSIS

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :NO2SIGAN.087
ISCST3 OUTPUT FILE NUMBER 2 :NO2SIGAN.088
ISCST3 OUTPUT FILE NUMBER 3 :NO2SIGAN.089
ISCST3 OUTPUT FILE NUMBER 4 :NO2SIGAN.090
ISCST3 OUTPUT FILE NUMBER 5 :NO2SIGAN.091
First title for last output file is: 1987 OSCEOLA FARMS NO2 SIG IMPACT- ANNUAL 8/23/04
Second title for last output file is: NO. MONTHS: EXIST- 7; FUTURE- 7

AVERAGING TIME	YEAR	CONC (ug/m3)	DIRECTION (degree)	DISTANCE (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL					
Annual					
	1987	0.80170	271.0	1219.4	87123124
	1988	1.27369	271.0	1219.4	88123124
	1989	0.95242	275.7	1225.2	89123124
	1990	1.82343	271.0	1219.4	90123124
	1991	1.01426	266.3	1221.8	91123124

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

```
CO STARTING
CO TITLEONE 1987 OSCEOLA FARMS NO2 SIG IMPACT- ANNUAL   8/23/04
CO TITLETWO NO. MONTHS: EXIST- 7; FUTURE- 7
CO MODELOPT DFAULT CONC   RURAL NOCMPL
CO AVERTIME PERIOD
CO POLLUTID NO2
CO DCAYCOEF    .000000
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
**          SRCID SRCTYP        XS        YS        ZS
**                              (m)       (m)       (m)
** ORIGIN
SO LOCATION ORIGIN    POINT       0         0.        0.
SO SRCPARAM ORIGIN    0.00      10.0      273       10.0       1.0

** EXISTING UNITS
SO LOCATION OSB4E    POINT      154.6     -10.5       0.
SO LOCATION OSB5AE   POINT      146.6       8.4       0.
SO LOCATION OSB5BE   POINT      164.6      14.7       0.

** FUTURE UNITS
SO LOCATION OSB4     POINT      154.6     -10.5       0.
SO LOCATION OSB5A    POINT      146.6       8.4       0.
SO LOCATION OSB5B    POINT      164.6      14.7       0.

** Source Parameter Cards:
** POINT:   SRCID       QS        HS         TS     VS         DS
**                     (g/s)      (m)        (K)   (m/s)       (m)
** EXISTING UNITS- ANNUAL
SO SRCPARAM OSB4E    -3.95      27.4     340.7    11.9      1.83
SO SRCPARAM OSB5AE   -1.94      27.4     340.7     9.7      1.52
SO SRCPARAM OSB5BE   -1.94      27.4     340.4     8.3      1.52

** FUTURE UNITS- ANNUAL
SO SRCPARAM OSB4      7.50      27.4     340.7    21.4      1.83
SO SRCPARAM OSB5A     3.75      27.4     340.7    17.5      1.52
SO SRCPARAM OSB5B     3.75      27.4     340.4    17.5      1.52

SO BUILDHGT OSB4E     0.00     0.00     0.00    21.34    21.34    21.34
SO BUILDHGT OSB4E    36.58    36.58    21.34    21.34    21.34    21.34
SO BUILDHGT OSB4E    21.34    21.34    21.34    21.34    21.34    21.34
SO BUILDHGT OSB4E     0.00     0.00     0.00    21.34    21.34    21.34
SO BUILDHGT OSB4E    21.34    21.34    21.34    21.34    21.34    21.34
SO BUILDHGT OSB4E    21.34    21.34    21.34    21.34    21.34    21.34
SO BUILDWID OSB4E     0.00     0.00     0.00    95.56   101.40   104.16
SO BUILDWID OSB4E    39.75    33.43    93.60   101.80   106.90   108.76
SO BUILDWID OSB4E   107.31   102.60    94.78    84.07    76.60    71.40
SO BUILDWID OSB4E     0.00     0.00     0.00    95.56   101.40   104.16
SO BUILDWID OSB4E   103.76   100.20    93.60   101.80   106.90   108.76
SO BUILDWID OSB4E   107.31   102.60    94.78    84.07    76.60    71.40


SO BUILDHGT OSB5AE    0.00     0.00     0.00     0.00     0.00    36.58
SO BUILDHGT OSB5AE   36.58    36.58    21.34    21.34    21.34    21.34
SO BUILDHGT OSB5AE   21.34    21.34    21.34    21.34    21.34     0.00
SO BUILDHGT OSB5AE    0.00     0.00     0.00     0.00     0.00     0.00
SO BUILDHGT OSB5AE   21.34    21.34    21.34    21.34    21.34    21.34
SO BUILDHGT OSB5AE   21.34    21.34    21.34    21.34    21.34     0.00
SO BUILDWID OSB5AE    0.00     0.00     0.00     0.00     0.00    44.85
SO BUILDWID OSB5AE   39.75    33.43    93.60   101.80   106.90   108.76
SO BUILDWID OSB5AE  107.31   102.60    94.78    84.07    76.60     0.00
SO BUILDWID OSB5AE    0.00     0.00     0.00     0.00     0.00     0.00
SO BUILDWID OSB5AE  103.76   100.20    93.60   101.80   106.90   108.76
SO BUILDWID OSB5AE  107.31   102.60    94.78    84.07    76.60     0.00


SO BUILDHGT OSB5BE   21.34     0.00     0.00     0.00     0.00    36.58
SO BUILDHGT OSB5BE   36.58    36.58    21.34    21.34    21.34    21.34
SO BUILDHGT OSB5BE   21.34    21.34    21.34    21.34    21.34    21.34
SO BUILDHGT OSB5BE   21.34     0.00     0.00     0.00     0.00    21.34
SO BUILDHGT OSB5BE   21.34    21.34    21.34    21.34    21.34    21.34
SO BUILDHGT OSB5BE   21.34    21.34    21.34    21.34    21.34    21.34
SO BUILDWID OSB5BE   73.81     0.00     0.00     0.00     0.00    44.85
SO BUILDWID OSB5BE   39.75    33.43    93.60   101.80   106.90   108.76
SO BUILDWID OSB5BE  107.31   102.60    94.78    84.07    76.60    71.40
SO BUILDWID OSB5BE   73.81     0.00     0.00     0.00     0.00   104.16
SO BUILDWID OSB5BE  103.76   100.20    93.60   101.80   106.90   108.76
SO BUILDWID OSB5BE  107.31   102.60    94.78    84.07    76.60    71.40
```

```
SO BUILDHGT OSB4      0.00    0.00    0.00   21.34   21.34   21.34
SO BUILDHGT OSB4     36.58   36.58   21.34   21.34   21.34   21.34
SO BUILDHGT OSB4     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSB4      0.00    0.00    0.00   21.34   21.34   21.34
SO BUILDHGT OSB4     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSB4     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSB4      0.00    0.00    0.00   95.56  101.40  104.16
SO BUILDWID OSB4     39.75   33.43   93.60  101.80  106.90  108.76
SO BUILDWID OSB4    107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSB4      0.00    0.00    0.00   95.56  101.40  104.16
SO BUILDWID OSB4    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSB4    107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSB5A     0.00    0.00    0.00    0.00    0.00   36.58
SO BUILDHGT OSB5A    36.58   36.58   21.34   21.34   21.34   21.34
SO BUILDHGT OSB5A    21.34   21.34   21.34   21.34   21.34    0.00
SO BUILDHGT OSB5A     0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT OSB5A    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSB5A    21.34   21.34   21.34   21.34   21.34    0.00
SO BUILDWID OSB5A     0.00    0.00    0.00    0.00    0.00   44.85
SO BUILDWID OSB5A    39.75   33.43   93.60  101.80  106.90  108.76
SO BUILDWID OSB5A   107.31  102.60   94.78   84.07   76.60    0.00
SO BUILDWID OSB5A     0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDWID OSB5A   103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSB5A   107.31  102.60   94.78   84.07   76.60    0.00

SO BUILDHGT OSB5B    21.34    0.00    0.00    0.00    0.00   36.58
SO BUILDHGT OSB5B    36.58   36.58   21.34   21.34   21.34   21.34
SO BUILDHGT OSB5B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSB5B    21.34    0.00    0.00    0.00    0.00   21.34
SO BUILDHGT OSB5B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSB5B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSB5B    73.81    0.00    0.00    0.00    0.00   44.85
SO BUILDWID OSB5B    39.75   33.43   93.60  101.80  106.90  108.76
SO BUILDWID OSB5B   107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSB5B    73.81    0.00    0.00    0.00    0.00  104.16
SO BUILDWID OSB5B   103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSB5B   107.31  102.60   94.78   84.07   76.60   71.40

   Monthly Emission Factors for Mill Sources
SO EMISFACT OSB4E            MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OSB5AE           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OSB5BE           MONTH 1 1 1 1 0 0 0 0 0 1 1 1

SO EMISFACT OSB4             MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OSB5A            MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OSB5B            MONTH 1 1 1 1 0 0 0 0 0 1 1 1

SO EMISUNIT    .100000E+07 (GRAMS/SEC)          (MICROGRAMS/CUBIC-METER)
SO SRCGROUP ALL
SO FINISHED

RE STARTING
RE GRIDPOLR POL STA
RE GRIDPOLR POL ORIG   0.0    0.0
RE GRIDPOLR POL DIST  4000 5000 6000 7000 8000 9000 10000 11000 12000 13000 14000
RE GRIDPOLR POL DIST  15000 20000 25000 30000 35000
RE GRIDPOLR POL GDIR   36  10.00  10.00
RE GRIDPOLR POL END
**  FENCELINE RECEPTORS AT 100-M INTERVALS
RE DISCCART    -1219.2    2987.0
RE DISCCART    -1119.2    2987.0
RE DISCCART    -1019.2    2987.0
RE DISCCART     -919.2    2987.0
RE DISCCART     -819.2    2987.0
RE DISCCART     -719.2    2987.0
RE DISCCART     -619.2    2987.0
RE DISCCART     -519.2    2987.0
RE DISCCART     -419.2    2987.0
RE DISCCART     -319.2    2987.0
RE DISCCART     -219.2    2987.0
RE DISCCART     -119.2    2987.0
RE DISCCART      -19.2    2987.0
RE DISCCART       80.8    2987.0
RE DISCCART      180.8    2987.0
RE DISCCART      280.8    2987.0
RE DISCCART      380.8    2987.0
RE DISCCART      480.8    2987.0
RE DISCCART      580.8    2987.0
RE DISCCART      680.8    2987.0
RE DISCCART      780.8    2987.0
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RE DISCCART      880.8    2987.0
RE DISCCART      980.8    2987.0
RE DISCCART     1080.8    2987.0
RE DISCCART     1180.8    2987.0
RE DISCCART     1280.8    2987.0
RE DISCCART     1380.8    2987.0
RE DISCCART     1480.8    2987.0
RE DISCCART     1580.8    2987.0
RE DISCCART     1680.8    2987.0
RE DISCCART     1780.8    2987.0
RE DISCCART     1880.8    2987.0
RE DISCCART     1980.8    2987.0
RE DISCCART     2080.8    2987.0
RE DISCCART     2180.8    2987.0
RE DISCCART     2280.8    2987.0
RE DISCCART     2380.8    2987.0
RE DISCCART     2480.8    2987.0
RE DISCCART     2580.8    2987.0
RE DISCCART     2680.8    2987.0
RE DISCCART     2743.2    2949.4
RE DISCCART     2743.2    2849.4
RE DISCCART     2743.2    2749.4
RE DISCCART     2743.2    2649.4
RE DISCCART     2743.2    2549.4
RE DISCCART     2743.2    2449.4
RE DISCCART     2743.2    2349.4
RE DISCCART     2743.2    2249.4
RE DISCCART     2743.2    2149.4
RE DISCCART     2743.2    2049.4
RE DISCCART     2743.2    1949.4
RE DISCCART     2743.2    1849.4
RE DISCCART     2743.2    1749.4
RE DISCCART     2743.2    1649.4
RE DISCCART     2743.2    1549.4
RE DISCCART     2743.2    1449.4
RE DISCCART     2743.2    1349.4
RE DISCCART     2743.2    1249.4
RE DISCCART     2673.4    1219.2
RE DISCCART     2573.4    1219.2
RE DISCCART     2473.4    1219.2
RE DISCCART     2373.4    1219.2
RE DISCCART     2273.4    1219.2
RE DISCCART     2173.4    1219.2
RE DISCCART     2073.4    1219.2
RE DISCCART     1973.4    1219.2
RE DISCCART     1950.7    1141.9
RE DISCCART     1950.7    1041.9
RE DISCCART     1950.7     941.9
RE DISCCART     1950.7     841.9
RE DISCCART     1950.7     741.9
RE DISCCART     1950.7     641.9
RE DISCCART     1950.7     541.9
RE DISCCART     1950.7     441.9
RE DISCCART     1950.7     341.9
RE DISCCART     1950.7     241.9
RE DISCCART     1950.7     141.9
RE DISCCART     1950.7      41.9
RE DISCCART     1950.7     -58.1
RE DISCCART     1950.7    -158.1
RE DISCCART     2025.9    -182.9
RE DISCCART     2125.9    -182.9
RE DISCCART     2225.9    -182.9
RE DISCCART     2316.5    -192.3
RE DISCCART     2316.5    -292.3
RE DISCCART     2316.5    -392.3
RE DISCCART     2316.5    -492.3
RE DISCCART     2316.5    -592.3
RE DISCCART     2316.5    -692.3
RE DISCCART     2316.5    -792.3
RE DISCCART     2316.5    -892.3
RE DISCCART     2316.5    -992.3
RE DISCCART     2248.3   -1024.1
RE DISCCART     2148.3   -1024.1
RE DISCCART     2048.3   -1024.1
RE DISCCART     1948.3   -1024.1
RE DISCCART     1848.3   -1024.1
RE DISCCART     1748.3   -1024.1
RE DISCCART     1648.3   -1024.1
RE DISCCART     1548.3   -1024.1
RE DISCCART     1448.3   -1024.1
RE DISCCART     1348.3   -1024.1
RE DISCCART     1249.7   -1025.5
RE DISCCART     1249.7   -1125.5
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RE DISCCART     1249.7   -1225.5
RE DISCCART     1249.7   -1325.5
RE DISCCART     1249.7   -1425.5
RE DISCCART     1249.7   -1525.5
RE DISCCART     1249.7   -1625.5
RE DISCCART     1249.7   -1725.5
RE DISCCART     1192.0   -1767.8
RE DISCCART     1092.0   -1767.8
RE DISCCART      992.0   -1767.8
RE DISCCART      892.0   -1767.8
RE DISCCART      792.0   -1767.8
RE DISCCART      692.0   -1767.8
RE DISCCART      592.0   -1767.8
RE DISCCART      492.0   -1767.8
RE DISCCART      392.0   -1767.8
RE DISCCART      365.8   -1694.1
RE DISCCART      365.8   -1594.1
RE DISCCART      365.8   -1494.1
RE DISCCART      365.8   -1394.1
RE DISCCART      365.8   -1294.1
RE DISCCART      365.8   -1194.1
RE DISCCART      365.8   -1094.1
RE DISCCART      335.7   -1024.1
RE DISCCART      235.7   -1024.1
RE DISCCART      135.7   -1024.1
RE DISCCART       35.7   -1024.1
RE DISCCART      -64.3   -1024.1
RE DISCCART     -164.3   -1024.1
RE DISCCART     -264.3   -1024.1
RE DISCCART     -364.3   -1024.1
RE DISCCART     -464.3   -1024.1
RE DISCCART     -564.3   -1024.1
RE DISCCART     -664.3   -1024.1
RE DISCCART     -764.3   -1024.1
RE DISCCART     -864.3   -1024.1
RE DISCCART     -964.3   -1024.1
RE DISCCART    -1064.3   -1024.1
RE DISCCART    -1164.3   -1024.1
RE DISCCART    -1219.2    -979.0
RE DISCCART    -1219.2    -879.0
RE DISCCART    -1219.2    -779.0
RE DISCCART    -1219.2    -679.0
RE DISCCART    -1219.2    -579.0
RE DISCCART    -1219.2    -479.0
RE DISCCART    -1219.2    -379.0
RE DISCCART    -1219.2    -279.0
RE DISCCART    -1219.2    -179.0
RE DISCCART    -1219.2     -79.0
RE DISCCART    -1219.2      21.0
RE DISCCART    -1219.2     121.0
RE DISCCART    -1219.2     221.0
RE DISCCART    -1219.2     321.0
RE DISCCART    -1219.2     421.0
RE DISCCART    -1219.2     521.0
RE DISCCART    -1219.2     621.0
RE DISCCART    -1219.2     721.0
RE DISCCART    -1219.2     821.0
RE DISCCART    -1219.2     921.0
RE DISCCART    -1219.2    1021.0
RE DISCCART    -1219.2    1121.0
RE DISCCART    -1219.2    1221.0
RE DISCCART    -1219.2    1321.0
RE DISCCART    -1219.2    1421.0
RE DISCCART    -1219.2    1521.0
RE DISCCART    -1219.2    1621.0
RE DISCCART    -1219.2    1721.0
RE DISCCART    -1219.2    1821.0
RE DISCCART    -1219.2    1921.0
RE DISCCART    -1219.2    2021.0
RE DISCCART    -1219.2    2121.0
RE DISCCART    -1219.2    2221.0
RE DISCCART    -1219.2    2321.0
RE DISCCART    -1219.2    2421.0
RE DISCCART    -1219.2    2521.0
RE DISCCART    -1219.2    2621.0
RE DISCCART    -1219.2    2721.0
RE DISCCART    -1219.2    2821.0
RE DISCCART    -1219.2    2921.0
RE DISCPOLR ORIGIN     3000.          70
RE DISCPOLR ORIGIN     2000.          80
RE DISCPOLR ORIGIN     3000.          80
RE DISCPOLR ORIGIN     2000.          90
RE DISCPOLR ORIGIN     3000.          90
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RE DISCPOLR ORIGIN     3000.        100
RE DISCPOLR ORIGIN     3000.        110
RE DISCPOLR ORIGIN     3000.        120
RE DISCPOLR ORIGIN     2000.        130
RE DISCPOLR ORIGIN     3000.        130
RE DISCPOLR ORIGIN     2000.        140
RE DISCPOLR ORIGIN     3000.        140
RE DISCPOLR ORIGIN     3000.        150
RE DISCPOLR ORIGIN     2000.        160
RE DISCPOLR ORIGIN     3000.        160
RE DISCPOLR ORIGIN     1200.        170
RE DISCPOLR ORIGIN     1500.        170
RE DISCPOLR ORIGIN     2000.        170
RE DISCPOLR ORIGIN     3000.        170
RE DISCPOLR ORIGIN     1200.        180
RE DISCPOLR ORIGIN     1500.        180
RE DISCPOLR ORIGIN     2000.        180
RE DISCPOLR ORIGIN     3000.        180
RE DISCPOLR ORIGIN     1200.        190
RE DISCPOLR ORIGIN     1500.        190
RE DISCPOLR ORIGIN     2000.        190
RE DISCPOLR ORIGIN     3000.        190
RE DISCPOLR ORIGIN     1200.        200
RE DISCPOLR ORIGIN     1500.        200
RE DISCPOLR ORIGIN     2000.        200
RE DISCPOLR ORIGIN     3000.        200
RE DISCPOLR ORIGIN     1200.        210
RE DISCPOLR ORIGIN     1500.        210
RE DISCPOLR ORIGIN     2000.        210
RE DISCPOLR ORIGIN     3000.        210
RE DISCPOLR ORIGIN     1500.        220
RE DISCPOLR ORIGIN     2000.        220
RE DISCPOLR ORIGIN     3000.        220
RE DISCPOLR ORIGIN     2000.        230
RE DISCPOLR ORIGIN     3000.        230
RE DISCPOLR ORIGIN     1500.        240
RE DISCPOLR ORIGIN     2000.        240
RE DISCPOLR ORIGIN     3000.        240
RE DISCPOLR ORIGIN     1500.        250
RE DISCPOLR ORIGIN     2000.        250
RE DISCPOLR ORIGIN     3000.        250
RE DISCPOLR ORIGIN     1500.        260
RE DISCPOLR ORIGIN     2000.        260
RE DISCPOLR ORIGIN     3000.        260
RE DISCPOLR ORIGIN     1500.        270
RE DISCPOLR ORIGIN     2000.        270
RE DISCPOLR ORIGIN     3000.        270
RE DISCPOLR ORIGIN     1500.        280
RE DISCPOLR ORIGIN     2000.        280
RE DISCPOLR ORIGIN     3000.        280
RE DISCPOLR ORIGIN     1500.        290
RE DISCPOLR ORIGIN     2000.        290
RE DISCPOLR ORIGIN     3000.        290
RE DISCPOLR ORIGIN     1500.        300
RE DISCPOLR ORIGIN     2000.        300
RE DISCPOLR ORIGIN     3000.        300
RE DISCPOLR ORIGIN     2000.        310
RE DISCPOLR ORIGIN     3000.        310
RE DISCPOLR ORIGIN     2000.        320
RE DISCPOLR ORIGIN     3000.        320
RE DISCPOLR ORIGIN     3000.        330
RE DISCPOLR ORIGIN     3000.        360
RE FINISHED

ME STARTING
ME INPUTFIL c:\MET\PBIPBI87.MET
ME ANEMHGHT    33  FEET
ME SURFDATA  12844      1987   WEST-PALM-BCH
ME UAIRDATA  12844      1987   WEST-PALM-BCH
ME FINISHED

OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
```

AAQS IMPACT ANALYSIS

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :NOAQAN.087
ISCST3 OUTPUT FILE NUMBER 2 :NOAQAN.088
ISCST3 OUTPUT FILE NUMBER 3 :NOAQAN.089
ISCST3 OUTPUT FILE NUMBER 4 :NOAQAN.090
ISCST3 OUTPUT FILE NUMBER 5 :NOAQAN.091
st title for last output file is: 1987 NO2 ANNUAL AAQS ANALYSIS, OSCEOLA BLR 4&5 8/25/04
cond title for last output file is: SCREENING

AVERAGING TIME	YEAR	CONC (ug/m3)	DIRECTION (degree)	DISTANCE (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	ALL				
Annual					
	1987	13.28228	134.4	1750.3	87123124
	1988	15.81514	271.0	1219.4	88123124
	1989	14.43621	275.7	1225.2	89123124
	1990	19.00541	266.3	1221.8	90123124
	1991	13.97085	261.6	1232.3	91123124
SOURCE GROUP ID:	OSFARM				
Annual					
	1987	7.90449	134.4	1750.3	87123124
	1988	9.72351	271.0	1219.4	88123124
	1989	7.87707	275.7	1225.2	89123124
	1990	13.53537	266.3	1221.8	90123124
	1991	8.38437	261.6	1232.3	91123124

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

```
CO STARTING
CO TITLEONE 1987 NO2 ANNUAL AAQS ANALYSIS, OSCEOLA BLR 4&5 8/25/04
CO TITLETWO SCREENING
CO MODELOPT DFAULT CONC   RURAL NOCMPL
CO AVERTIME PERIOD
   POLLUTID NOX
   DCAYCOEF    .000000
   RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
**         SRCID SRCTYP        XS        YS        ZS
**                             (m)       (m)       (m)
** COGEN STACKS MIDPOINT ARE ORIGIN LOCATION (MODELED WITH ZERO EMISSIONS)
SO LOCATION ORIGIN    POINT        0         0         0.

**FUTURE FACILITY
SO LOCATION OSBLR4     POINT      154.6    -10.5       0.
SO LOCATION OSBLR5A    POINT      146.6      8.4       0.
SO LOCATION OSBLR5B    POINT      164.6     14.7       0.

SO LOCATION OSBLR2   POINT      164.6  -37.0          0.
SO LOCATION OSBLR3   POINT      166.3  -27.7          0.
SO LOCATION OSBLR6   POINT      132.3  -25.2         0.

**USSUGAR BRYANT
SO LOCATION USBRY123        POINT   -6900   1820    0.0
SO LOCATION USBRY5  POINT   -6900   1820    0.0
SO LOCATION USBRY7  POINT   -6900   1820    0.0
SO LOCATION USBRY8  POINT   -6900   1820    0.0

**SUGAR CANE GROWERS
SO LOCATION SUGCN12 POINT   -9800   -14000  0.0
SO LOCATION SUGCN3  POINT   -9800   -14000  0.0
SO LOCATION SUGCN4  POINT   -9800   -14000  0.0
SO LOCATION SUGCN5  POINT   -9800   -14000  0.0
SO LOCATION SUGCN8  POINT   -9800   -14000  0.0

**EL PASO BELLE GLADE
   LOCATION EPBGCT1 POINT   -11200  -13200  0.0
   LOCATION EPBGSC23        POINT   -11200  -13200  0.0

**UNITED TECHNOLOGIES
SO LOCATION UTECH1  POINT   17300   8700    0.0
SO LOCATION UTECH16 POINT   17300   8700    0.0
SO LOCATION UTECH22 POINT   17300   8700    0.0
SO LOCATION UTECH40 POINT   17300   8700    0.0
SO LOCATION UTECH45 POINT   17300   8700    0.0
SO LOCATION UTECH59 POINT   17300   8700    0.0
SO LOCATION UTECH66 POINT   17300   8700    0.0
SO LOCATION UTECH67 POINT   17300   8700    0.0
SO LOCATION UTECH68 POINT   17300   8700    0.0
SO LOCATION UTECH69 POINT   17300   8700    0.0
SO LOCATION UTECHA10        POINT   17300   8700    0.0

**BECHTEL INDIANTOWN
SO LOCATION INDTWN1 POINT    900    24200   0.0
SO LOCATION INDTWN3 POINT    900    24200   0.0

**ATLANTIC SUGAR
SO LOCATION ATLSUG1 POINT   8200    -22100  0.0
SO LOCATION ATLSUG2 POINT   8200    -22100  0.0
SO LOCATION ATLSUG3 POINT   8200    -22100  0.0
SO LOCATION ATLSUG4 POINT   8200    -22100  0.0
SO LOCATION ATLSUG5 POINT   8200    -22100  0.0

**FPL MARTIN
SO LOCATION MART12  POINT   -1600   25600   0.0
SO LOCATION MART34  POINT   -1600   25600   0.0
SO LOCATION MARTCTs POINT   -1600   25600   0.0
SO LOCATION MART8   POINT   -1600   25600   0.0

**OKEELANTA
SO LOCATION OKBLR16 POINT   -19700  -29900  0.0
   LOCATION OKCOGEN POINT   -20610  -27290  0.0

   VERGLADES SUGAR
SO LOCATION EVERGLAD        POINT   -35100  -13100  0.0

**US SUGAR CLEWISTON
**OFF-CROP SEASON
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SO LOCATION USSBRL1F        POINT   -38600  -10400  0.0
SO LOCATION USSBLR2F        POINT   -38600  -10400  0.0

SO LOCATION USSBLR4F        POINT   -38600  -10400  0.0
SO LOCATION USSBLR7F        POINT   -38600  -10400  0.0
**NON-CROP SEASON
SO LOCATION USSBRL1N        POINT   -38600  -10400  0.0
SO LOCATION USSBLR2N        POINT   -38600  -10400  0.0

SO LOCATION USSBLR4N        POINT   -38600  -10400  0.0
SO LOCATION USSBLR7N        POINT   -38600  -10400  0.0
SO LOCATION USSBLN8         POINT   -38600  -10400  0.0
SO LOCATION USSS12          POINT   -38600  -10400  0.0

**SOLID WASTE AUTHORITY OF PBC
SO LOCATION SWAPB1  POINT   39790   -6040   0.0
SO LOCATION SWAPB2  POINT   39790   -6040   0.0
SO LOCATION SWAPB3  POINT   39790   -6040   0.0
SO LOCATION SWAPB4  POINT   39790   -6040   0.0

**FPL RIVERIA
SO LOCATION RIVU34  POINT   49500   -6700   0.0

**LAKE WORTH UTILITIES
SO LOCATION LAKWTH15        POINT   48100   -23600  0.0
SO LOCATION LAKWTH6 POINT   48100   -23600  0.0
SO LOCATION LAKWTH8 POINT   48100   -23600  0.0
SO LOCATION LAKWTH10        POINT   48100   -23600  0.0

**FT PIERCE UTILITIES
SO LOCATION FTPRC1  POINT   21420   69050   0.0
SO LOCATION FTPRC2  POINT   21420   69050   0.0
SO LOCATION FTPRC3  POINT   21420   69050   0.0
SO LOCATION FTPRC4  POINT   21420   69050   0.0
SO LOCATION FTPRC7  POINT   21420   69050   0.0
SO LOCATION FTPRC8  POINT   21420   69050   0.0
SO LOCATION FTPRC10 POINT   21420   69050   0.0

**WHEELABRATOR NORTH BROWARD
SO LOCATION WHEELN1 POINT   39200   -59700  0.0
SO LOCATION WHEELN2 POINT   39200   -59700  0.0
SO LOCATION WHEELN3 POINT   39200   -59700  0.0

**CITY OF VERO BEACH
SO LOCATION VERO1   POINT   16700   89200   0.0
SO LOCATION VERO2   POINT   16700   89200   0.0
SO LOCATION VERO3   POINT   16700   89200   0.0
SO LOCATION VERO4   POINT   16700   89200   0.0
SO LOCATION VERO5   POINT   16700   89200   0.0

**SOUTH BROWARD RRF
SO LOCATION SBROW1  POINT   34900   -84000  0.0
SO LOCATION SBROW2  POINT   34900   -84000  0.0
SO LOCATION SBROW3  POINT   34900   -84000  0.0

**FPL-LAUDERDALE
SO LOCATION FPLCT3  POINT   35400   -84000  0.0
SO LOCATION FPLCT15 POINT   35400   -84000  0.0
SO LOCATION FPLCT35 POINT   35400   -84000  0.0
SO LOCATION FPLCT36 POINT   35400   -84000  0.0
SO LOCATION FPLCT37 POINT   35400   -84000  0.0
SO LOCATION FPLCT38 POINT   35400   -84000  0.0

**FPL-PORT EVERGLADES
SO LOCATION FPPE1   POINT   42700   -82000  0.0
SO LOCATION FPPE2   POINT   42700   -82000  0.0
SO LOCATION FPPE3   POINT   42700   -82000  0.0
SO LOCATION FPPE4   POINT   42700   -82000  0.0
SO LOCATION FPPE5   POINT   42700   -82000  0.0

**TECO PHILLIPS
SO LOCATION TECO1   POINT   -80400  68100   0.0
SO LOCATION TECO2   POINT   -80400  68100   0.0

**TARMAC
SO LOCATION TARM4   POINT   18200   -105600 0.0
SO LOCATION TARM6   POINT   18200   -105600 0.0
SO LOCATION TARM20  POINT   18200   -105600 0.0

**MIAMI-DADE RRF/MONTENAY
SO LOCATION MDADE14 POINT   19130   -109680 0.0

**FPL-FORT MYERS
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SO LOCATION FMYGT112        POINT   -122600 -14400  0.0
SO LOCATION FMYHR16 POINT   -122600 -14400  0.0
SO LOCATION FMCT1_2 POINT   -122600 -14400  0.0

** Source Parameter Cards:
   POINT:    SRCID          QS       HS         TS     VS          DS
                          (g/s)      (m)        (K)   (m/s)        (m)
   FUTURE UNITS- ANNUAL
SO SRCPARAM ORIGIN     0.00     61.0      391.5   20.6       2.44

SO SRCPARAM OSBLR4       7.50       27.4     340.7     21.4      1.83
SO SRCPARAM OSBLR5A      3.75       27.4     340.7     17.5      1.52
SO SRCPARAM OSBLR5B      3.75       27.4     340.4     17.5      1.52

SO SRCPARAM OSBLR2      6.86       27.4     341.0   15.82      1.52
SO SRCPARAM OSBLR3      16.56      27.4     342.0   16.86      1.91
SO SRCPARAM OSBLR6      7.64       27.4     341.0   18.19      1.88

**USSUGAR BRYANT
SO SRCPARAM USBRY123  65.49  19.8    342.0    36.4     1.64
SO SRCPARAM USBRY5  20.37    45.7     345.4    14.8     2.90
SO SRCPARAM USBRY7  7.54     8.53     519.3    12.19    0.37
SO SRCPARAM USBRY8  7.99     8.53     519.3    12.80    0.37
**SUGAR CANE GROWERS
SO SRCPARAM SUGCN12 37.88    45.7     339.0    21.75    1.87
SO SRCPARAM SUGCN3  12.96    27.4     339.0    22.25    1.52
SO SRCPARAM SUGCN4  32.41    54.9     339.0    21.73    2.44
SO SRCPARAM SUGCN5  24.90    45.7     339.0    15.94    2.30
SO SRCPARAM SUGCN8  15.50    47.2     339.0    13.62    2.90

**EL PASO BELLE GLADE
SO SRCPARAM EPBGCT1 2.06     41.1     359.3    18.63    5.79
SO SRCPARAM EPBGSC23         8.43     41.1     862.0    44.79    5.79

**UNITED TECHNOLOGIES
SO SRCPARAM UTECH1       16.48   15.2     810.9    143.73  0.91
SO SRCPARAM UTECH16      0.76    4.6      533.0    6.92    0.76
SO SRCPARAM UTECH22      1.83    20.1     671.9    10.19   2.32
SO SRCPARAM UTECH40      0.15    14.9     298.2    0.04    1.20
SO SRCPARAM UTECH45      0.00    3.7      298.2    2.60    0.20
SO SRCPARAM UTECH59      0.91    6.1      533.2    4.90    0.50
    RCPARAM UTECH66      0.13    7.3      513.6    33.17   0.41
    RCPARAM UTECH67      0.02    7.3      513.6    0.32    0.30
SO SRCPARAM UTECH68      6.72    3.7      922.0    51.40   0.20
SO SRCPARAM UTECH69      23.43   5.5      422.0    0.08    3.70
SO SRCPARAM UTECHA10     1.12    5.8      410.9    106.68  4.17

**BECHTEL INDIANTOWN
SO SRCPARAM INDTWN1 73.33    150.9    333.2    30.50    4.88
SO SRCPARAM INDTWN3 9.02     64.0     449.8    26.70    1.52

**ATLANTIC SUGAR
SO SRCPARAM ATLSUG1 31.75    27.4     344.3    16.82    1.89
SO SRCPARAM ATLSUG2 31.75    27.4     344.3    12.50    1.89
SO SRCPARAM ATLSUG3 14.74    18.3     338.7    16.15    1.83
SO SRCPARAM ATLSUG4 15.59    27.4     338.7    16.15    1.83
SO SRCPARAM ATLSUG5 2.00     27.4     338.7    19.20    1.68

**FPL MARTIN
SO SRCPARAM MART12  653.94  152.1     420.9    21.03    7.99
SO SRCPARAM MART34  89.21    64.9     410.9    18.90    6.10
SO SRCPARAM MARTCTs 93.39    18.3     853.2    37.63    6.71
SO SRCPARAM MART8   19.51    36.6     420.0    22.40    5.79

**OKEELANTA
SO SRCPARAM OKBLR16 3.28     22.9     483.2    22.86    1.52
SO SRCPARAM OKCOGEN 24.84    60.7     450.9    19.39    3.05

**EVERGLADES SUGAR
SO SRCPARAM EVERGLAD         4.82     21.9     477.6    10.06    1.07

**US SUGAR CLEWISTON
**OFF-CROP SEASON
SO SRCPARAM USSBRL1F         4.10     65.0     347.0    19.20    2.44
SO SRCPARAM USSBLR2F         4.10     65.0     338.0 7  17.32    2.44

    RCPARAM USSBLR4F         0.00     45.7     344.3     6.78    2.51
    RCPARAM USSBLR7F         9.56     68.6     405.4    24.05    2.59

**ON-CROP SEASON
SO SRCPARAM USSBRL1N         9.03     65.0     347.0    17.70    2.44
SO SRCPARAM USSBLR2N         8.31     65.0     338.0 7  16.19    2.44
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SO SRCPARAM USSBLR4N        10.89   45.7    344.3    6.20   2.51
SO SRCPARAM USSBLR7N        13.71   68.6    405.4   23.60   2.59
SO SRCPARAM USSBLN8         17.54   60.7    439.0   15.31   3.96
SO SRCPARAM USSS12           0.38    9.1    344.3    6.90   0.61

**SOLID WASTE AUTHORITY OF PBC
SO SRCPARAM SWAPB1  24.98   76.2    505.2   24.90   2.04
SO SRCPARAM SWAPB2  24.98   76.2    505.2   24.90   2.04
SO SRCPARAM SWAPB3  0.46    7.0     1033.0  24.44   0.21
SO SRCPARAM SWAPB4  0.46    7.0     1033.0  46.57   0.15

**FPL RIVERIA
SO SRCPARAM RIVU34  476.53  90.8    401.5   18.90   4.88

**LAKE WORTH UTILITIES
SO SRCPARAM LAKWTH15        62.87   5.2     625.9   37.09   0.56
SO SRCPARAM LAKWTH6         49.39   14.0    720.4   24.84   4.88
SO SRCPARAM LAKWTH8         20.54   34.4    418.2   15.67   2.13
SO SRCPARAM LAKWTH10        36.04   22.9    481.0   27.80   3.05

**FT PIERCE UTILITIES
SO SRCPARAM FTPRC1      11.30   7.0     783.0      11.89   0.91
SO SRCPARAM FTPRC2      11.30   7.0     783.0      11.89   0.91
SO SRCPARAM FTPRC3      17.07   20.7    491.9      18.23   3.41
SO SRCPARAM FTPRC4      0.16    45.1    435.8      10.97   1.52
SO SRCPARAM FTPRC7      13.16   44.8    426.3      18.62   2.16
SO SRCPARAM FTPRC8      4.82    45.7    440.8      25.48   2.44
SO SRCPARAM FTPRC10     2.41    45.7    440.8      25.48   2.44

**WHEELABRATOR NORTH BROWARD
SO SRCPARAM WHEELN1    209.33  58.5    381.0   18.01    3.96
SO SRCPARAM WHEELN2    209.33  58.5    381.0   18.01    3.96
SO SRCPARAM WHEELN3    209.33  58.5    381.0   18.01    3.96

**CITY OF VERO BEACH
SO SRCPARAM VERO1   13.59   61.0    437.0   32.42   1.07
SO SRCPARAM VERO2   16.70   61.0    434.3   37.57   1.07
SO SRCPARAM VERO3   28.09   61.0    440.4   19.93   1.83
SO SRCPARAM VERO4   51.85   61.0    425.4   24.36   2.13
SO SRCPARAM VERO5   14.04   19.4    416.3   19.39   3.35

**SOUTH BROWARD RRF
SO SRCPARAM SBROW1  22.86   59.4    380.8   18.01   3.96
SO SRCPARAM SBROW2  22.86   59.4    380.8   18.01   3.96
SO SRCPARAM SBROW3  22.86   59.4    380.8   18.01   3.96

**FPL-LAUDERDALE
SO SRCPARAM FPLCT3  148.65  13.7    733.0   114.30  2.37
SO SRCPARAM FPLCT15 148.65  13.4    733.0   28.44   4.75
SO SRCPARAM FPLCT35 88.27   45.7    438.7   14.60   5.49
SO SRCPARAM FPLCT36 88.27   45.7    438.7   14.60   5.49
SO SRCPARAM FPLCT37 47.20   45.7    438.7   14.60   5.49
SO SRCPARAM FPLCT38 88.27   45.7    438.7   14.60   5.49

**FPL-PORT EVERGLADES
SO SRCPARAM FPPE1   165.00  104.5   415.9   26.70   4.27
SO SRCPARAM FPPE2   165.00  104.5   415.9   26.70   4.27
SO SRCPARAM FPPE3   478.34  104.5   414.8   23.90   5.52
SO SRCPARAM FPPE4   478.34  104.5   414.8   23.90   5.52
SO SRCPARAM FPPE5   191.03  13.4    683.0   10.67   4.75

**TECO PHILLIPS
SO SRCPARAM TECO1   72.13   45.7    441.3   24.08   1.83
SO SRCPARAM TECO2   72.13   45.7    449.7   24.08   1.83

**TARMAC
SO SRCPARAM TARM4   24.98   61.0    421.9    9.10   2.44
SO SRCPARAM TARM6   74.71   61.0    450.0   11.04   4.57
SO SRCPARAM TARM20  0.37    9.1     421.9   17.98   1.22

**MIAMI-DADE RRF/MONTENAY
SO SRCPARAM MDADE14         70.84   76.2    405.4   15.86   3.66

**FPL-FORT MYERS
SO SRCPARAM FMYGT112        900.00  9.8     797.0   57.73   4.42
SO SRCPARAM FMYHR16         49.14   38.1    377.6   14.20   5.79
SO SRCPARAM FMCT1_2         84.12   24.4    852.0   39.08   6.25

**BUILDING DOWNWASH CARDS
SO BUILDHGT OSBLR2      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2      21.34   36.58   36.58   36.58   21.34   21.34
SO BUILDHGT OSBLR2      21.34   21.34   21.34   21.34   21.34   21.34
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SO BUILDHGT OSBLR2      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR2      73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR2     103.76   30.24   26.10   30.24  106.90  108.76
SO BUILDWID OSBLR2     107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR2      73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR2     103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR2     107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSBLR3      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3      21.34   36.58   36.58   21.34   21.34   21.34
SO BUILDHGT OSBLR3      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR3      73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR3     103.76   32.74   26.10  101.80  106.90  108.76
SO BUILDWID OSBLR3     107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR3      73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR3     103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR3     107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSBLR4       0.00    0.00    0.00   21.34   21.34   21.34
SO BUILDHGT OSBLR4      36.58   36.58   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4       0.00    0.00    0.00   21.34   21.34   21.34
SO BUILDHGT OSBLR4      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR4       0.00    0.00    0.00   95.56  101.40  104.16
SO BUILDWID OSBLR4      39.75   33.43   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR4     107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR4       0.00    0.00    0.00   95.56  101.40  104.16
SO BUILDWID OSBLR4     103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR4     107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSBLR5A      0.00    0.00    0.00    0.00    0.00   36.58
SO BUILDHGT OSBLR5A     36.58   36.58   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5A     21.34   21.34   21.34   21.34   21.34    0.00
SO BUILDHGT OSBLR5A      0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT OSBLR5A     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5A     21.34   21.34   21.34   21.34   21.34    0.00
SO BUILDWID OSBLR5A      0.00    0.00    0.00    0.00    0.00   44.85
SO BUILDWID OSBLR5A     39.75   33.43   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5A    107.31  102.60   94.78   84.07   76.60    0.00
SO BUILDWID OSBLR5A      0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDWID OSBLR5A    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5A    107.31  102.60   94.78   84.07   76.60    0.00

SO BUILDHGT OSBLR5B     21.34    0.00    0.00    0.00    0.00   36.58
SO BUILDHGT OSBLR5B     36.58   36.58   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5B     21.34    0.00    0.00    0.00    0.00   21.34
SO BUILDHGT OSBLR5B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR5B     73.81    0.00    0.00    0.00    0.00   44.85
SO BUILDWID OSBLR5B     39.75   33.43   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5B    107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR5B     73.81    0.00    0.00    0.00    0.00  104.16
SO BUILDWID OSBLR5B    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5B    107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSBLR6       0.00    0.00    0.00    0.00   21.34   21.34
SO BUILDHGT OSBLR6      36.58   36.58   36.58   21.34   21.34   21.34
SO BUILDHGT OSBLR6      21.34   21.34   21.34   21.34    0.00    0.00
SO BUILDHGT OSBLR6       0.00    0.00    0.00    0.00   21.34   21.34
SO BUILDHGT OSBLR6      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR6      21.34   21.34   21.34   21.34    0.00    0.00
SO BUILDWID OSBLR6       0.00    0.00    0.00    0.00  101.40  104.16
SO BUILDWID OSBLR6      35.28   33.43   26.10  101.80  106.90  108.76
SO BUILDWID OSBLR6     107.31  102.60   94.78   84.07    0.00    0.00
SO BUILDWID OSBLR6       0.00    0.00    0.00    0.00  101.40  104.16
SO BUILDWID OSBLR6     103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR6     107.31  102.60   94.78   84.07    0.00    0.00

** Monthly Emission Factors for Mill Sources
SO EMISFACT OSBLR4           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OSBLR5A          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
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SO EMISFACT OSBLR5B         MONTH 1 1 1 1 0 0 0 0 0 1 1 1

SO EMISFACT OSBLR2-OSBLR3   MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OSBLR6          MONTH 1 1 1 1 0 0 0 0 0 1 1 1

** Monthly Emission Factors for Other Mill Sources
SO EMISFACT USBRY123        MONTH 1 1 1 1 1 1 0 0 0 1 1 1
SO EMISFACT USBRY5          MONTH 1 1 1 1 1 1 0 0 0 1 1 1
SO EMISFACT USBRY7          MONTH 1 1 1 1 1 1 0 0 0 1 1 1
SO EMISFACT USBRY8          MONTH 1 1 1 1 1 1 0 0 0 1 1 1
SO EMISFACT SUGCN12         MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT SUGCN3          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT SUGCN4          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT SUGCN5          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT SUGCN8          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT ATLSUG1         MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT ATLSUG2         MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT ATLSUG3         MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT ATLSUG4         MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT ATLSUG5         MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OKBLR16         MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT USSBRL1N        MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT USSBLR2N        MONTH 1 1 1 1 0 0 0 0 0 1 1 1

SO EMISFACT USSBLR4N        MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT USSBLR7N        MONTH 1 1 1 1 0 0 0 0 0 1 1 1

**OFF-CROP SEASON SOURCES
SO EMISFACT USSBRL1F        MONTH 0 0 0 0 1 1 1 1 1 0 0 0
SO EMISFACT USSBLR2F        MONTH 0 0 0 0 1 1 1 1 1 0 0 0

SO EMISFACT USSBLR4F        MONTH 0 0 0 0 1 1 1 1 1 0 0 0
SO EMISFACT USSBLR7F        MONTH 0 0 0 0 1 1 1 1 1 0 0 0

SO EMISUNIT    .100000E+07 (GRAMS/SEC)          (MICROGRAMS/CUBIC-METER)

SO SRCGROUP ALL
SO SRCGROUP OSFARM   OSBLR4 OSBLR5A OSBLR5B OSBLR2 OSBLR3 OSBLR6

SO FINISHED

RE STARTING
RE GRIDPOLR POL STA
RE GRIDPOLR POL ORIG   0.0   0.0
RE GRIDPOLR POL DIST  4000 5000
RE GRIDPOLR POL GDIR   36  10.00  10.00
RE GRIDPOLR POL END
**  FENCELINE RECEPTORS AT 100-M INTERVALS
RE DISCCART    -1219.2    2987.0
RE DISCCART    -1119.2    2987.0
RE DISCCART    -1019.2    2987.0
RE DISCCART     -919.2    2987.0
RE DISCCART     -819.2    2987.0
RE DISCCART     -719.2    2987.0
RE DISCCART     -619.2    2987.0
RE DISCCART     -519.2    2987.0
RE DISCCART     -419.2    2987.0
RE DISCCART     -319.2    2987.0
RE DISCCART     -219.2    2987.0
RE DISCCART     -119.2    2987.0
RE DISCCART      -19.2    2987.0
RE DISCCART       80.8    2987.0
RE DISCCART      180.8    2987.0
RE DISCCART      280.8    2987.0
RE DISCCART      380.8    2987.0
RE DISCCART      480.8    2987.0
RE DISCCART      580.8    2987.0
RE DISCCART      680.8    2987.0
RE DISCCART      780.8    2987.0
RE DISCCART      880.8    2987.0
RE DISCCART      980.8    2987.0
RE DISCCART     1080.8    2987.0
RE DISCCART     1180.8    2987.0
RE DISCCART     1280.8    2987.0
RE DISCCART     1380.8    2987.0
RE DISCCART     1480.8    2987.0
RE DISCCART     1580.8    2987.0
RE DISCCART     1680.8    2987.0
RE DISCCART     1780.8    2987.0
RE DISCCART     1880.8    2987.0
RE DISCCART     1980.8    2987.0
RE DISCCART     2080.8    2987.0
RE DISCCART     2180.8    2987.0
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RE DISCCART     2280.8    2987.0
RE DISCCART     2380.8    2987.0
RE DISCCART     2480.8    2987.0
RE DISCCART     2580.8    2987.0
RE DISCCART     2680.8    2987.0
RE DISCCART     2743.2    2949.4
RE DISCCART     2743.2    2849.4
RE DISCCART     2743.2    2749.4
RE DISCCART     2743.2    2649.4
RE DISCCART     2743.2    2549.4
RE DISCCART     2743.2    2449.4
RE DISCCART     2743.2    2349.4
RE DISCCART     2743.2    2249.4
RE DISCCART     2743.2    2149.4
RE DISCCART     2743.2    2049.4
RE DISCCART     2743.2    1949.4
RE DISCCART     2743.2    1849.4
RE DISCCART     2743.2    1749.4
RE DISCCART     2743.2    1649.4
RE DISCCART     2743.2    1549.4
RE DISCCART     2743.2    1449.4
RE DISCCART     2743.2    1349.4
RE DISCCART     2743.2    1249.4
RE DISCCART     2673.4    1219.2
RE DISCCART     2573.4    1219.2
RE DISCCART     2473.4    1219.2
RE DISCCART     2373.4    1219.2
RE DISCCART     2273.4    1219.2
RE DISCCART     2173.4    1219.2
RE DISCCART     2073.4    1219.2
RE DISCCART     1973.4    1219.2
RE DISCCART     1950.7    1141.9
RE DISCCART     1950.7    1041.9
RE DISCCART     1950.7     941.9
RE DISCCART     1950.7     841.9
RE DISCCART     1950.7     741.9
RE DISCCART     1950.7     641.9
RE DISCCART     1950.7     541.9
RE DISCCART     1950.7     441.9
RE DISCCART     1950.7     341.9
RE DISCCART     1950.7     241.9
RE DISCCART     1950.7     141.9
RE DISCCART     1950.7      41.9
RE DISCCART     1950.7     -58.1
RE DISCCART     1950.7    -158.1
RE DISCCART     2025.9    -182.9
RE DISCCART     2125.9    -182.9
RE DISCCART     2225.9    -182.9
RE DISCCART     2316.5    -192.3
RE DISCCART     2316.5    -292.3
RE DISCCART     2316.5    -392.3
RE DISCCART     2316.5    -492.3
RE DISCCART     2316.5    -592.3
RE DISCCART     2316.5    -692.3
RE DISCCART     2316.5    -792.3
RE DISCCART     2316.5    -892.3
RE DISCCART     2316.5    -992.3
RE DISCCART     2248.3   -1024.1
RE DISCCART     2148.3   -1024.1
RE DISCCART     2048.3   -1024.1
RE DISCCART     1948.3   -1024.1
RE DISCCART     1848.3   -1024.1
RE DISCCART     1748.3   -1024.1
RE DISCCART     1648.3   -1024.1
RE DISCCART     1548.3   -1024.1
RE DISCCART     1448.3   -1024.1
RE DISCCART     1348.3   -1024.1
RE DISCCART     1249.7   -1025.5
RE DISCCART     1249.7   -1125.5
RE DISCCART     1249.7   -1225.5
RE DISCCART     1249.7   -1325.5
RE DISCCART     1249.7   -1425.5
RE DISCCART     1249.7   -1525.5
RE DISCCART     1249.7   -1625.5
RE DISCCART     1249.7   -1725.5
RE DISCCART     1192.0   -1767.8
RE DISCCART     1092.0   -1767.8
RE DISCCART      992.0   -1767.8
RE DISCCART      892.0   -1767.8
RE DISCCART      792.0   -1767.8
RE DISCCART      692.0   -1767.8
RE DISCCART      592.0   -1767.8
RE DISCCART      492.0   -1767.8
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RE DISCCART      392.0   -1767.8
RE DISCCART      365.8   -1694.1
RE DISCCART      365.8   -1594.1
RE DISCCART      365.8   -1494.1
RE DISCCART      365.8   -1394.1
RE DISCCART      365.8   -1294.1
RE DISCCART      365.8   -1194.1
RE DISCCART      365.8   -1094.1
RE DISCCART      335.7   -1024.1
RE DISCCART      235.7   -1024.1
RE DISCCART      135.7   -1024.1
RE DISCCART       35.7   -1024.1
RE DISCCART      -64.3   -1024.1
RE DISCCART     -164.3   -1024.1
RE DISCCART     -264.3   -1024.1
RE DISCCART     -364.3   -1024.1
RE DISCCART     -464.3   -1024.1
RE DISCCART     -564.3   -1024.1
RE DISCCART     -664.3   -1024.1
RE DISCCART     -764.3   -1024.1
RE DISCCART     -864.3   -1024.1
RE DISCCART     -964.3   -1024.1
RE DISCCART    -1064.3   -1024.1
RE DISCCART    -1164.3   -1024.1
RE DISCCART    -1219.2    -979.0
RE DISCCART    -1219.2    -879.0
RE DISCCART    -1219.2    -779.0
RE DISCCART    -1219.2    -679.0
RE DISCCART    -1219.2    -579.0
RE DISCCART    -1219.2    -479.0
RE DISCCART    -1219.2    -379.0
RE DISCCART    -1219.2    -279.0
RE DISCCART    -1219.2    -179.0
RE DISCCART    -1219.2     -79.0
RE DISCCART    -1219.2      21.0
RE DISCCART    -1219.2     121.0
RE DISCCART    -1219.2     221.0
RE DISCCART    -1219.2     321.0
RE DISCCART    -1219.2     421.0
RE DISCCART    -1219.2     521.0
RE DISCCART    -1219.2     621.0
RE DISCCART    -1219.2     721.0
RE DISCCART    -1219.2     821.0
RE DISCCART    -1219.2     921.0
RE DISCCART    -1219.2    1021.0
RE DISCCART    -1219.2    1121.0
RE DISCCART    -1219.2    1221.0
RE DISCCART    -1219.2    1321.0
RE DISCCART    -1219.2    1421.0
RE DISCCART    -1219.2    1521.0
RE DISCCART    -1219.2    1621.0
RE DISCCART    -1219.2    1721.0
RE DISCCART    -1219.2    1821.0
RE DISCCART    -1219.2    1921.0
RE DISCCART    -1219.2    2021.0
RE DISCCART    -1219.2    2121.0
RE DISCCART    -1219.2    2221.0
RE DISCCART    -1219.2    2321.0
RE DISCCART    -1219.2    2421.0
RE DISCCART    -1219.2    2521.0
RE DISCCART    -1219.2    2621.0
RE DISCCART    -1219.2    2721.0
RE DISCCART    -1219.2    2821.0
RE DISCCART    -1219.2    2921.0
RE DISCPOLR ORIGIN     3000.        70
RE DISCPOLR ORIGIN     2000.        80
RE DISCPOLR ORIGIN     3000.        80
RE DISCPOLR ORIGIN     2000.        90
RE DISCPOLR ORIGIN     3000.        90
RE DISCPOLR ORIGIN     3000.       100
RE DISCPOLR ORIGIN     3000.       110
RE DISCPOLR ORIGIN     3000.       120
RE DISCPOLR ORIGIN     2000.       130
RE DISCPOLR ORIGIN     3000.       130
RE DISCPOLR ORIGIN     2000.       140
RE DISCPOLR ORIGIN     3000.       140
RE DISCPOLR ORIGIN     3000.       150
RE DISCPOLR ORIGIN     2000.       160
RE DISCPOLR ORIGIN     3000.       160
RE DISCPOLR ORIGIN     1200.       170
RE DISCPOLR ORIGIN     1500.       170
RE DISCPOLR ORIGIN     2000.       170
RE DISCPOLR ORIGIN     3000.       170
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RE DISCPOLR ORIGIN     1200.        180
RE DISCPOLR ORIGIN     1500.        180
RE DISCPOLR ORIGIN     2000.        180
RE DISCPOLR ORIGIN     3000.        180
RE DISCPOLR ORIGIN     1200.        190
RE DISCPOLR ORIGIN     1500.        190
RE DISCPOLR ORIGIN     2000.        190
RE DISCPOLR ORIGIN     3000.        190
RE DISCPOLR ORIGIN     1200.        200
RE DISCPOLR ORIGIN     1500.        200
RE DISCPOLR ORIGIN     2000.        200
RE DISCPOLR ORIGIN     3000.        200
RE DISCPOLR ORIGIN     1200.        210
RE DISCPOLR ORIGIN     1500.        210
RE DISCPOLR ORIGIN     2000.        210
RE DISCPOLR ORIGIN     3000.        210
RE DISCPOLR ORIGIN     1500.        220
RE DISCPOLR ORIGIN     2000.        220
RE DISCPOLR ORIGIN     3000.        220
RE DISCPOLR ORIGIN     2000.        230
RE DISCPOLR ORIGIN     3000.        230
RE DISCPOLR ORIGIN     1500.        240
RE DISCPOLR ORIGIN     2000.        240
RE DISCPOLR ORIGIN     3000.        240
RE DISCPOLR ORIGIN     1500.        250
RE DISCPOLR ORIGIN     2000.        250
RE DISCPOLR ORIGIN     3000.        250
RE DISCPOLR ORIGIN     1500.        260
RE DISCPOLR ORIGIN     2000.        260
RE DISCPOLR ORIGIN     3000.        260
RE DISCPOLR ORIGIN     1500.        270
RE DISCPOLR ORIGIN     2000.        270
RE DISCPOLR ORIGIN     3000.        270
RE DISCPOLR ORIGIN     1500.        280
RE DISCPOLR ORIGIN     2000.        280
RE DISCPOLR ORIGIN     3000.        280
RE DISCPOLR ORIGIN     1500.        290
RE DISCPOLR ORIGIN     2000.        290
RE DISCPOLR ORIGIN     3000.        290
RE DISCPOLR ORIGIN     1500.        300
RE DISCPOLR ORIGIN     2000.        300
RE DISCPOLR ORIGIN     3000.        300
RE DISCPOLR ORIGIN     2000.        310
RE DISCPOLR ORIGIN     3000.        310
RE DISCPOLR ORIGIN     2000.        320
RE DISCPOLR ORIGIN     3000.        320
RE DISCPOLR ORIGIN     3000.        330
RE DISCPOLR ORIGIN     3000.        360
RE FINISHED

ME STARTING
ME INPUTFIL C:\MET\PBIPBI87.MET
ME ANEMHGHT    33  FEET
ME SURFDATA  12844      1987   WEST-PALM-BCH
ME UAIRDATA  12844      1987   WEST-PALM-BCH
ME FINISHED

OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
```

PSD CLASS II IMPACT ANALYSIS

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :NOPSDAN.087
ISCST3 OUTPUT FILE NUMBER 2 :NOPSDAN.088
ISCST3 OUTPUT FILE NUMBER 3 :NOPSDAN.089
ISCST3 OUTPUT FILE NUMBER 4 :NOPSDAN.090
ISCST3 OUTPUT FILE NUMBER 5 :NOPSDAN.091
First title for last output file is: 1987 NO2 PSD CLASS II ANALYSIS, OSCEOLA BLR 4&5 8/25/04
Second title for last output file is: SCREENING

AVERAGING TIME	YEAR	CONC (ug/m3)	DIRECTION (degree)	DISTANCE (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL					
Annual					
	1987	5.65318	134.4	1750.3	87123124
	1988	7.63512	271.0	1219.4	88123124
	1989	6.24878	275.7	1225.2	89123124
	1990	10.38665	266.3	1221.8	90123124
	1991	6.65657	261.6	1232.3	91123124
SOURCE GROUP ID: OSFARM					
Annual					
	1987	5.01137	134.4	1750.3	87123124
	1988	6.90989	271.0	1219.4	88123124
	1989	5.47988	275.7	1225.2	89123124
	1990	9.64714	266.3	1221.8	90123124
	1991	5.84931	261.6	1232.3	91123124

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

```
CO STARTING
CO TITLEONE 1987 NO2 PSD CLASS II ANALYSIS, OSCEOLA BLR 4&5 8/25/04
CO TITLETWO SCREENING
CO MODELOPT DFAULT CONC   RURAL NOCMPL
CO AVERTIME PERIOD
CO POLLUTID NOX
CO DCAYCOEF    .000000
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
**         SRCID SRCTYP       XS        YS       ZS
**                            (m)       (m)      (m)
** COGEN STACKS MIDPOINT ARE ORIGIN LOCATION (MODELED WITH ZERO EMISSIONS)
SO LOCATION ORIGIN    POINT        0         0        0.

**FUTURE FACILITY
SO LOCATION OSBLR4     POINT      154.6    -10.5      0.
SO LOCATION OSBLR5A    POINT      146.6      8.4      0.
SO LOCATION OSBLR5B    POINT      164.6     14.7      0.

SO LOCATION OSBLR2   POINT      164.6  -37.0          0.
SO LOCATION OSBLR3   POINT      166.3  -27.7          0.
SO LOCATION OSBLR6   POINT      132.3  -25.2         0.

**OSCEOLA FARMS BASELINE
SO LOCATION OSBLR2B  POINT      164.6    -37.0      0.
SO LOCATION OSBLR3B  POINT      166.3    -27.7      0.
SO LOCATION OSBLR4B  POINT      154.6    -10.5      0.
SO LOCATION OSBLR5BB POINT      164.6     14.7      0.
SO LOCATION OSBLR6B  POINT      132.3    -25.2      0.

**SUGAR CANE GROWERS
SO LOCATION SUGCN12 POINT   -9800    -14000  0.0
SO LOCATION SUGCN3  POINT   -9800    -14000  0.0
SO LOCATION SUGCN4  POINT   -9800    -14000  0.0
SO LOCATION SUGCN5  POINT   -9800    -14000  0.0
SO LOCATION SUGCN8  POINT   -9800    -14000  0.0
SO LOCATION SUGCN12B        POINT   -9800    -14000  0.0
SO LOCATION SUGCN3B POINT   -9800    -14000  0.0
SO LOCATION SUGCN4B POINT   -9800    -14000  0.0
SO LOCATION SUGCN5B POINT   -9800    -14000  0.0
SO LOCATION SUGCN8B POINT   -9800    -14000  0.0

**EL PASO BELLE GLADE
SO LOCATION EPBGCT1 POINT   -11200  -13200  0.0
SO LOCATION EPBGSC23        POINT   -11200  -13200  0.0

**UNITED TECHNOLOGIES
SO LOCATION UTECH1  POINT   17300   8700    0.0
SO LOCATION UTECH22 POINT   17300   8700    0.0
SO LOCATION UTECH40 POINT   17300   8700    0.0
SO LOCATION UTECH45 POINT   17300   8700    0.0
SO LOCATION UTECH59 POINT   17300   8700    0.0
SO LOCATION UTECH66 POINT   17300   8700    0.0
SO LOCATION UTECH67 POINT   17300   8700    0.0

**BECHTEL INDIANTOWN
SO LOCATION INDTWN1 POINT    900    24200   0.0
SO LOCATION INDTWN3 POINT    900    24200   0.0

**ATLANTIC SUGAR
SO LOCATION ATLSUG5 POINT   8200    -22100  0.0
SO LOCATION ATLSUG5B        POINT   8200    -22100  0.0

**FPL MARTIN
SO LOCATION MART34  POINT   -1600   25600   0.0
SO LOCATION MARTCTs POINT   -1600   25600   0.0
SO LOCATION MART8   POINT   -1600   25600   0.0

**OKEELANTA
SO LOCATION OKBLR4B POINT   -19700  -29900  0.0
SO LOCATION OKBLR5B POINT   -19700  -29900  0.0
SO LOCATION OKBLR6B POINT   -19700  -29900  0.0
SO LOCATION OKBLR10B        POINT   -19700  -29900  0.0
SO LOCATION OKBLR11B        POINT   -19700  -29900  0.0
SO LOCATION OKBLR12B        POINT   -19700  -29900  0.0
SO LOCATION OKBLR14B        POINT   -19700  -29900  0.0
SO LOCATION OKBLR15B        POINT   -19700  -29900  0.0
SO LOCATION OKBLR16 POINT   -19700  -29900  0.0
SO LOCATION OKCOGEN POINT   -20610  -27390  0.0
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**US SUGAR CLEWISTON
SO LOCATION BRL1B   POINT   -38600  -10400  0.0
SO LOCATION BLR2B   POINT   -38600  -10400  0.0

SO LOCATION BLR4B   POINT   -38600  -10400  0.0
SO LOCATION BLR5B   POINT   -38600  -10400  0.0
SO LOCATION BLR6B   POINT   -38600  -10400  0.0

**OFF-CROP SEASON
SO LOCATION USSBRL1F        POINT   -38600  -10400  0.0
SO LOCATION USSBLR2F        POINT   -38600  -10400  0.0

SO LOCATION USSBLR4F        POINT   -38600  -10400  0.0
SO LOCATION USSBLR7F        POINT   -38600  -10400  0.0

**ON-CROP SEASON
SO LOCATION USSBRL1N        POINT   -38600  -10400  0.0
SO LOCATION USSBLR2N        POINT   -38600  -10400  0.0

SO LOCATION USSBLR4N        POINT   -38600  -10400  0.0
SO LOCATION USSBLR7N        POINT   -38600  -10400  0.0
SO LOCATION USSBLR8         POINT   -38600  -10400  0.0
SO LOCATION USS12           POINT   -38600  -10400  0.0

**CITY OF VERO BEACH
SO LOCATION VERO5   POINT   16700   89200   0.0

**SOUTH BROWARD RRF
SO LOCATION SBROW1  POINT   34900   -84000  0.0
SO LOCATION SBROW2  POINT   34900   -84000  0.0
SO LOCATION SBROW3  POINT   34900   -84000  0.0

**FPL-LAUDERDALE
SO LOCATION FPLCT35 POINT   35400   -84000  0.0
SO LOCATION FPLCT36 POINT   35400   -84000  0.0
SO LOCATION FPLCT37 POINT   35400   -84000  0.0
SO LOCATION FPLCT38 POINT   35400   -84000  0.0

**TARMAC
SO LOCATION TARM4   POINT   18200   -105600 0.0
SO LOCATION TARM6   POINT   18200   -105600 0.0
SO LOCATION TARM20  POINT   18200   -105600 0.0
SO LOCATION TARM3B  POINT   18200   -105600 0.0

**MIAMI-DADE RRF/MONTENAY
SO LOCATION MDADE14 POINT   19130   -109680 0.0
SO LOCATION MDADE14B        POINT   19130   -109680 0.0

**FPL-FORT MYERS
SO LOCATION FMYHR16 POINT   -122600 -14400  0.0
SO LOCATION FMCT1_2 POINT   -122600 -14400  0.0
SO LOCATION FMU1B   POINT   -122600 -14400  0.0
SO LOCATION FMU2B   POINT   -122600 -14400  0.0

** Source Parameter Cards:
** POINT:   SRCID       QS       HS         TS     VS         DS
**                    (g/s)      (m)        (K)    (m/s)      (m)
** FUTURE UNITS- ANNUAL
SO SRCPARAM ORIGIN     0.00     61.0      391.5   20.6       2.44

SO SRCPARAM OSBLR4      7.50       27.4    340.7     21.4      1.83
SO SRCPARAM OSBLR5A     3.75       27.4    340.7     17.5      1.52
SO SRCPARAM OSBLR5B     3.75       27.4    340.4     17.5      1.52

SO SRCPARAM OSBLR2    6.86      27.4    341.0   15.82      1.52
SO SRCPARAM OSBLR3    16.56     27.4    342.0   16.86      1.91
SO SRCPARAM OSBLR6    7.64      27.4    341.0   18.19      1.88

**OSCEOLA FARMS BASELINE
SO SRCPARAM OSBLR2B -1.88    22.0     342.0    14.22    1.52
SO SRCPARAM OSBLR3B -0.84    22.0     342.0    11.23    1.93
SO SRCPARAM OSBLR4B -1.52    22.0     342.0    13.35    1.83
SO SRCPARAM OSBLR5BB -4.83    22.0     342.0    12.02    1.52
SO SRCPARAM OSBLR6B -2.00    27.4     341.5    17.07    1.93

**SUGAR CANE GROWERS
SO SRCPARAM SUGCN12     37.88    45.7     339.0    21.75    1.87
SO SRCPARAM SUGCN3      12.96    27.4     339.0    22.25    1.52
SO SRCPARAM SUGCN4      32.41    54.9     339.0    21.73    2.44
SO SRCPARAM SUGCN5      24.90    45.7     339.0    15.94    2.30
SO SRCPARAM SUGCN8      15.50    47.2     339.0    13.62    2.90
SO SRCPARAM SUGCN12B    -3.40    24.4     344.0    11.40    1.40
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SO SRCPARAM SUGCN3B     -2.08   24.4    344.0   15.60   1.60
SO SRCPARAM SUGCN4B     -3.88   25.9    344.0   11.20   1.63
SO SRCPARAM SUGCN5B     -2.59   24.4    344.0   15.20   1.40
SO SRCPARAM SUGCN8B     -2.26   47.2    339.0   13.62   2.90

**EL PASO BELLE GLADE
SO SRCPARAM EPBGCT1 2.06    41.1    359.3   18.63   5.79
SO SRCPARAM EPBGSC23        8.43    41.1    862.0   44.79   5.79

**UNITED TECHNOLOGIES
SO SRCPARAM UTECH1  16.48   15.2    810.9   143.73  0.91
SO SRCPARAM UTECH22 1.83    20.1    671.9   10.19   2.32
SO SRCPARAM UTECH40 0.15    14.9    298.2   0.04    1.20
SO SRCPARAM UTECH45 0.00    3.7     298.2   2.60    0.20
SO SRCPARAM UTECH59 0.91    6.1     533.2   4.90    0.50
SO SRCPARAM UTECH66 0.13    7.3     513.6   33.17   0.41
SO SRCPARAM UTECH67 0.02    7.3     513.6   0.32    0.30

**BECHTEL INDIANTOWN
SO SRCPARAM INDTWN1 73.33   150.9   333.2   30.50   4.88
SO SRCPARAM INDTWN3 9.02    64.0    449.8   26.70   1.52

**ATLANTIC SUGAR
SO SRCPARAM ATLSUG5     2.00    27.4    338.7   19.20   1.68
SO SRCPARAM ATLSUG5B   -0.74    27.4    339.0   15.70   1.68

**FPL MARTIN
SO SRCPARAM MART34  89.21   64.9    410.9   18.90   6.10
SO SRCPARAM MARTCTs 93.39   18.3    853.2   37.63   6.71
SO SRCPARAM MART8   19.51   36.6    420.0   22.40   5.79

**OKEELANTA
SO SRCPARAM OKBLR4B         -1.36   22.9    333.0   7.36    2.29
SO SRCPARAM OKBLR5B         -1.89   22.9    333.0   12.07   2.29
SO SRCPARAM OKBLR6B         -1.59   22.9    334.0   8.74    2.29
SO SRCPARAM OKBLR10B        -1.80   22.9    334.0   10.35   2.29
SO SRCPARAM OKBLR11B        -2.30   22.9    342.0   9.89    2.29
SO SRCPARAM OKBLR12B        -2.88   22.9    330.0   8.20    2.29
SO SRCPARAM OKBLR14B        -3.18   22.9    333.0   8.30    2.29
SO SRCPARAM OKBLR15B        -2.52   22.9    332.0   10.20   2.29
SO SRCPARAM OKBLR16          3.28   22.9    483.2   22.86   1.52
SO SRCPARAM OKCOGEN         24.84   60.7    450.9   19.39   3.05

**US SUGAR CLEWISTON
SO SRCPARAM BRL1B   -6.27   23.1    344.0   30.20   1.86
SO SRCPARAM BLR2B   -6.29   23.1    343.0   35.70   1.86

SO SRCPARAM BLR4B   -8.76   45.7    344.3   25.40   2.51
SO SRCPARAM BLR5B   -1.54   23.1    494.0   44.30   1.86
SO SRCPARAM BLR6B   -1.34   23.1    494.0   44.30   1.86

**OFF-CROP SEASON
SO SRCPARAM USSBRL1F        4.10    65.0    347.0   19.20   2.44
SO SRCPARAM USSBLR2F        4.10    65.0    338.7   17.32   2.44

SO SRCPARAM USSBLR4F        0.00    45.7    344.3    6.78   2.51
SO SRCPARAM USSBLR7F        9.56    68.6    405.4   24.05   2.59

**ON-CROP SEASON
SO SRCPARAM USSBRL1N        9.03    65.0    347.0   17.70   2.44
SO SRCPARAM USSBLR2N        8.31    65.0    338.7   16.19   2.44

SO SRCPARAM USSBLR4N        10.89   45.7    344.3    6.20   2.51
SO SRCPARAM USSBLR7N        13.71   68.6    405.4   23.60   2.59
SO SRCPARAM USSBLR8          7.54   60.7    439.0   15.31   3.96
SO SRCPARAM USS12            0.38    9.1    344.3    6.90   0.61

**CITY OF VERO BEACH
SO SRCPARAM VERO5   14.04   19.4    416.3   19.39   3.35

**SOUTH BROWARD RRF
SO SRCPARAM SBROW1  22.86   59.4    380.8   18.01   3.96
SO SRCPARAM SBROW2  22.86   59.4    380.8   18.01   3.96
SO SRCPARAM SBROW3  22.86   59.4    380.8   18.01   3.96

**FPL-LAUDERDALE
SO SRCPARAM FPLCT35 88.27   45.7    438.7   14.60   5.49
SO SRCPARAM FPLCT36 88.27   45.7    438.7   14.60   5.49
SO SRCPARAM FPLCT37 47.20   45.7    438.7   14.60   5.49
SO SRCPARAM FPLCT38 88.27   45.7    438.7   14.60   5.49

**TARMAC
SO SRCPARAM TARM4   24.98   61.0    421.9    9.10   2.44
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SO SRCPARAM TARM6   74.71   61.0    450.0   11.04   4.57
SO SRCPARAM TARM20  0.37    9.1     421.9   17.98   1.22
SO SRCPARAM TARM3B  -60.83  61.0    450.0   11.04   4.57

**MIAMI-DADE RRF/MONTENAY
SO SRCPARAM MDADE14         70.84   76.2    405.4   15.86   3.66
SO SRCPARAM MDADE14B       -21.57   45.7    461.0   30.34   2.74

**FPL-FORT MYERS
SO SRCPARAM FMYHR16     49.14   38.1    377.6   14.20   5.79
SO SRCPARAM FMCT1_2     84.12   24.4    852.0   39.08   6.25
SO SRCPARAM FMU1B      -26.21   91.7    422.0   29.90   2.90
SO SRCPARAM FMU2B     -119.23  121.3    408.0   19.20   5.52



SO BUILDHGT OSBLR2      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2      21.34   36.58   36.58   36.58   21.34   21.34
SO BUILDHGT OSBLR2      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR2      73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR2     103.76   30.24   26.10   30.24  106.90  108.76
SO BUILDWID OSBLR2     107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR2      73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR2     103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR2     107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSBLR3      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3      21.34   36.58   36.58   21.34   21.34   21.34
SO BUILDHGT OSBLR3      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR3      73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR3     103.76   32.74   26.10  101.80  106.90  108.76
SO BUILDWID OSBLR3     107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR3      73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR3     103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR3     107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSBLR4       0.00    0.00    0.00   21.34   21.34   21.34
SO BUILDHGT OSBLR4      36.58   36.58   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4       0.00    0.00    0.00   21.34   21.34   21.34
SO BUILDHGT OSBLR4      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR4       0.00    0.00    0.00   95.56  101.40  104.16
SO BUILDWID OSBLR4      39.75   33.43   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR4     107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR4       0.00    0.00    0.00   95.56  101.40  104.16
SO BUILDWID OSBLR4     103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR4     107.31  102.60   94.78   84.07   76.60   71.40

SO BUILDHGT OSBLR5A      0.00    0.00    0.00    0.00    0.00   36.58
SO BUILDHGT OSBLR5A     36.58   36.58   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5A     21.34   21.34   21.34   21.34   21.34    0.00
SO BUILDHGT OSBLR5A      0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT OSBLR5A     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5A     21.34   21.34   21.34   21.34   21.34    0.00
SO BUILDWID OSBLR5A      0.00    0.00    0.00    0.00    0.00   44.85
SO BUILDWID OSBLR5A     39.75   33.43   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5A    107.31  102.60   94.78   84.07   76.60    0.00
SO BUILDWID OSBLR5A      0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDWID OSBLR5A    103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5A    107.31  102.60   94.78   84.07   76.60    0.00

SO BUILDHGT OSBLR5B     21.34    0.00    0.00    0.00    0.00   36.58
SO BUILDHGT OSBLR5B     36.58   36.58   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5B     21.34    0.00    0.00    0.00    0.00   21.34
SO BUILDHGT OSBLR5B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5B     21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR5B     73.81    0.00    0.00    0.00    0.00   44.85
SO BUILDWID OSBLR5B     39.75   33.43   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5B    107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR5B     73.81    0.00    0.00    0.00    0.00  104.16
SO BUILDWID OSBLR5B    103.76  100.20   93.60  101.80  106.90  108.76
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SO BUILDWID OSBLR5B    107.31  102.60   94.78   84.07   76.60   71.40


SO BUILDHGT OSBLR6       0.00    0.00    0.00    0.00   21.34   21.34
SO BUILDHGT OSBLR6      36.58   36.58   36.58   21.34   21.34   21.34
SO BUILDHGT OSBLR6      21.34   21.34   21.34   21.34    0.00    0.00
SO BUILDHGT OSBLR6       0.00    0.00    0.00    0.00   21.34   21.34
SO BUILDHGT OSBLR6      21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR6      21.34   21.34   21.34   21.34    0.00    0.00
SO BUILDWID OSBLR6       0.00    0.00    0.00    0.00  101.40  104.16
SO BUILDWID OSBLR6      35.28   33.43   26.10  101.80  106.90  108.76
SO BUILDWID OSBLR6     107.31  102.60   94.78   84.07    0.00    0.00
SO BUILDWID OSBLR6       0.00    0.00    0.00    0.00  101.40  104.16
SO BUILDWID OSBLR6     103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR6     107.31  102.60   94.78   84.07    0.00    0.00

SO BUILDHGT OSBLR2B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR2B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR2B    73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR2B   103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR2B   107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR2B    73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR2B   103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR2B   107.31  102.60   94.78   84.07   76.60   71.40


SO BUILDHGT OSBLR3B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR3B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR3B    73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR3B   103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR3B   107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR3B    73.81   75.43   86.81   95.56  101.40  104.16
SO BUILDWID OSBLR3B   103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR3B   107.31  102.60   94.78   84.07   76.60   71.40


SO BUILDHGT OSBLR4B     0.00    0.00    0.00   21.34   21.34   21.34
SO BUILDHGT OSBLR4B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4B     0.00    0.00    0.00   21.34   21.34   21.34
SO BUILDHGT OSBLR4B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR4B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDWID OSBLR4B     0.00    0.00    0.00   95.56  101.40  104.16
SO BUILDWID OSBLR4B   103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR4B   107.31  102.60   94.78   84.07   76.60   71.40
SO BUILDWID OSBLR4B     0.00    0.00    0.00   95.56  101.40  104.16
SO BUILDWID OSBLR4B   103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR4B   107.31  102.60   94.78   84.07   76.60   71.40


SO BUILDHGT OSBLR5BB    0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT OSBLR5BB    0.00   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5BB   21.34   21.34   21.34   21.34   21.34    0.00
SO BUILDHGT OSBLR5BB    0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT OSBLR5BB    0.00   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR5BB   21.34   21.34   21.34   21.34   21.34    0.00
SO BUILDWID OSBLR5BB    0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDWID OSBLR5BB    0.00  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5BB  107.31  102.60   94.78   84.07   76.60    0.00
SO BUILDWID OSBLR5BB    0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDWID OSBLR5BB    0.00  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR5BB  107.31  102.60   94.78   84.07   76.60    0.00


SO BUILDHGT OSBLR6B     0.00    0.00    0.00    0.00   21.34   21.34
SO BUILDHGT OSBLR6B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR6B    21.34   21.34   21.34   21.34    0.00    0.00
SO BUILDHGT OSBLR6B     0.00    0.00    0.00    0.00   21.34   21.34
SO BUILDHGT OSBLR6B    21.34   21.34   21.34   21.34   21.34   21.34
SO BUILDHGT OSBLR6B    21.34   21.34   21.34   21.34    0.00    0.00
SO BUILDWID OSBLR6B     0.00    0.00    0.00    0.00  101.40  104.16
SO BUILDWID OSBLR6B   103.76  100.20   93.60  101.80  106.90  108.76
SO BUILDWID OSBLR6B   107.31  102.60   94.78   84.07    0.00    0.00
SO BUILDWID OSBLR6B     0.00    0.00    0.00    0.00  101.40  104.16
SO BUILDWID OSBLR6B   103.76  100.20   93.60  101.80  106.90  108.76
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SO BUILDWID OSBLR6B   107.31  102.60   94.78   84.07    0.00    0.00

** Monthly Emission Factors for Mill Sources
SO EMISFACT OSBLR4            MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OSBLR5A           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OSBLR5B           MONTH 1 1 1 1 0 0 0 0 0 1 1 1

SO EMISFACT OSBLR2-OSBLR3     MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OSBLR6            MONTH 1 1 1 1 0 0 0 0 0 1 1 1

SO EMISFACT OSBLR2B           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OSBLR3B           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OSBLR4B           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OSBLR5BB          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OSBLR6B           MONTH 1 1 1 1 0 0 0 0 0 1 1 1

** Monthly Emission Factors for Other Mill Sources
SO EMISFACT SUGCN12           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT SUGCN3            MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT SUGCN4            MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT SUGCN5            MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT SUGCN8            MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT SUGCN12B          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT SUGCN3B           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT SUGCN4B           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT SUGCN5B           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT SUGCN8B           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT ATLSUG5B          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OKBLR4B           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OKBLR5B           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OKBLR6B           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OKBLR10B          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OKBLR11B          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OKBLR12B          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OKBLR14B          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OKBLR15B          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT OKBLR16           MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT BRL1B             MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT BLR2B             MONTH 1 1 1 1 0 0 0 0 0 1 1 1

SO EMISFACT BLR4B             MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT BLR5B             MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT BLR6B             MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT USSBRL1N          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT USSBLR2N          MONTH 1 1 1 1 0 0 0 0 0 1 1 1

SO EMISFACT USSBLR4N          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
SO EMISFACT USSBLR7N          MONTH 1 1 1 1 0 0 0 0 0 1 1 1
**OFF-CROP SEASON
SO EMISFACT USSBRL1F          MONTH 0 0 0 0 1 1 1 1 1 0 0 0
SO EMISFACT USSBLR2F          MONTH 0 0 0 0 1 1 1 1 1 0 0 0

SO EMISFACT USSBLR4F          MONTH 0 0 0 0 1 1 1 1 1 0 0 0
SO EMISFACT USSBLR7F          MONTH 0 0 0 0 1 1 1 1 1 0 0 0


SO EMISUNIT    .100000E+07 (GRAMS/SEC)          (MICROGRAMS/CUBIC-METER)

SO SRCGROUP ALL
SO SRCGROUP OSFARM   OSBLR4 OSBLR5A OSBLR5B OSBLR2 OSBLR3 OSBLR6
SO SRCGROUP OSFARM   OSBLR2B OSBLR3B OSBLR4B OSBLR5BB OSBLR6B

SO FINISHED

RE STARTING
RE GRIDPOLR POL STA
RE GRIDPOLR POL ORIG   0.0    0.0
RE GRIDPOLR POL DIST  4000 5000
RE GRIDPOLR POL GDIR   36  10.00  10.00
RE GRIDPOLR POL END
**  FENCELINE RECEPTORS AT 100-M INTERVALS
RE DISCCART    -1219.2    2987.0
RE DISCCART    -1119.2    2987.0
RE DISCCART    -1019.2    2987.0
RE DISCCART     -919.2    2987.0
RE DISCCART     -819.2    2987.0
RE DISCCART     -719.2    2987.0
RE DISCCART     -619.2    2987.0
RE DISCCART     -519.2    2987.0
RE DISCCART     -419.2    2987.0
RE DISCCART     -319.2    2987.0
RE DISCCART     -219.2    2987.0
RE DISCCART     -119.2    2987.0
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RE DISCCART      -19.2     2987.0
RE DISCCART       80.8     2987.0
RE DISCCART      180.8     2987.0
RE DISCCART      280.8     2987.0
RE DISCCART      380.8     2987.0
RE DISCCART      480.8     2987.0
RE DISCCART      580.8     2987.0
RE DISCCART      680.8     2987.0
RE DISCCART      780.8     2987.0
RE DISCCART      880.8     2987.0
RE DISCCART      980.8     2987.0
RE DISCCART     1080.8     2987.0
RE DISCCART     1180.8     2987.0
RE DISCCART     1280.8     2987.0
RE DISCCART     1380.8     2987.0
RE DISCCART     1480.8     2987.0
RE DISCCART     1580.8     2987.0
RE DISCCART     1680.8     2987.0
RE DISCCART     1780.8     2987.0
RE DISCCART     1880.8     2987.0
RE DISCCART     1980.8     2987.0
RE DISCCART     2080.8     2987.0
RE DISCCART     2180.8     2987.0
RE DISCCART     2280.8     2987.0
RE DISCCART     2380.8     2987.0
RE DISCCART     2480.8     2987.0
RE DISCCART     2580.8     2987.0
RE DISCCART     2680.8     2987.0
RE DISCCART     2743.2     2949.4
RE DISCCART     2743.2     2849.4
RE DISCCART     2743.2     2749.4
RE DISCCART     2743.2     2649.4
RE DISCCART     2743.2     2549.4
RE DISCCART     2743.2     2449.4
RE DISCCART     2743.2     2349.4
RE DISCCART     2743.2     2249.4
RE DISCCART     2743.2     2149.4
RE DISCCART     2743.2     2049.4
RE DISCCART     2743.2     1949.4
RE DISCCART     2743.2     1849.4
RE DISCCART     2743.2     1749.4
RE DISCCART     2743.2     1649.4
RE DISCCART     2743.2     1549.4
RE DISCCART     2743.2     1449.4
RE DISCCART     2743.2     1349.4
RE DISCCART     2743.2     1249.4
RE DISCCART     2673.4     1219.2
RE DISCCART     2573.4     1219.2
RE DISCCART     2473.4     1219.2
RE DISCCART     2373.4     1219.2
RE DISCCART     2273.4     1219.2
RE DISCCART     2173.4     1219.2
RE DISCCART     2073.4     1219.2
RE DISCCART     1973.4     1219.2
RE DISCCART     1950.7     1141.9
RE DISCCART     1950.7     1041.9
RE DISCCART     1950.7      941.9
RE DISCCART     1950.7      841.9
RE DISCCART     1950.7      741.9
RE DISCCART     1950.7      641.9
RE DISCCART     1950.7      541.9
RE DISCCART     1950.7      441.9
RE DISCCART     1950.7      341.9
RE DISCCART     1950.7      241.9
RE DISCCART     1950.7      141.9
RE DISCCART     1950.7       41.9
RE DISCCART     1950.7      -58.1
RE DISCCART     1950.7     -158.1
RE DISCCART     2025.9     -182.9
RE DISCCART     2125.9     -182.9
RE DISCCART     2225.9     -182.9
RE DISCCART     2316.5     -192.3
RE DISCCART     2316.5     -292.3
RE DISCCART     2316.5     -392.3
RE DISCCART     2316.5     -492.3
RE DISCCART     2316.5     -592.3
RE DISCCART     2316.5     -692.3
RE DISCCART     2316.5     -792.3
RE DISCCART     2316.5     -892.3
RE DISCCART     2316.5     -992.3
RE DISCCART     2248.3    -1024.1
RE DISCCART     2148.3    -1024.1
RE DISCCART     2048.3    -1024.1
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RE DISCCART     1948.3   -1024.1
RE DISCCART     1848.3   -1024.1
RE DISCCART     1748.3   -1024.1
RE DISCCART     1648.3   -1024.1
RE DISCCART     1548.3   -1024.1
RE DISCCART     1448.3   -1024.1
RE DISCCART     1348.3   -1024.1
RE DISCCART     1249.7   -1025.5
RE DISCCART     1249.7   -1125.5
RE DISCCART     1249.7   -1225.5
RE DISCCART     1249.7   -1325.5
RE DISCCART     1249.7   -1425.5
RE DISCCART     1249.7   -1525.5
RE DISCCART     1249.7   -1625.5
RE DISCCART     1249.7   -1725.5
RE DISCCART     1192.0   -1767.8
RE DISCCART     1092.0   -1767.8
RE DISCCART      992.0   -1767.8
RE DISCCART      892.0   -1767.8
RE DISCCART      792.0   -1767.8
RE DISCCART      692.0   -1767.8
RE DISCCART      592.0   -1767.8
RE DISCCART      492.0   -1767.8
RE DISCCART      392.0   -1767.8
RE DISCCART      365.8   -1694.1
RE DISCCART      365.8   -1594.1
RE DISCCART      365.8   -1494.1
RE DISCCART      365.8   -1394.1
RE DISCCART      365.8   -1294.1
RE DISCCART      365.8   -1194.1
RE DISCCART      365.8   -1094.1
RE DISCCART      335.7   -1024.1
RE DISCCART      235.7   -1024.1
RE DISCCART      135.7   -1024.1
RE DISCCART       35.7   -1024.1
RE DISCCART      -64.3   -1024.1
RE DISCCART     -164.3   -1024.1
RE DISCCART     -264.3   -1024.1
RE DISCCART     -364.3   -1024.1
RE DISCCART     -464.3   -1024.1
RE DISCCART     -564.3   -1024.1
RE DISCCART     -664.3   -1024.1
RE DISCCART     -764.3   -1024.1
RE DISCCART     -864.3   -1024.1
RE DISCCART     -964.3   -1024.1
RE DISCCART    -1064.3   -1024.1
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RE DISCCART    -1219.2    -979.0
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RE DISCCART    -1219.2    2021.0
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RE DISCCART    -1219.2    2221.0
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RE DISCCART    -1219.2    2821.0
RE DISCCART    -1219.2    2921.0
RE DISCPOLR ORIGIN     3000.        70
RE DISCPOLR ORIGIN     2000.        80
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RE DISCPOLR ORIGIN     2000.        90
RE DISCPOLR ORIGIN     3000.        90
RE DISCPOLR ORIGIN     3000.       100
RE DISCPOLR ORIGIN     3000.       110
RE DISCPOLR ORIGIN     3000.       120
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RE DISCPOLR ORIGIN     1200.       170
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RE DISCPOLR ORIGIN     2000.       320
RE DISCPOLR ORIGIN     3000.       320
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RE DISCPOLR ORIGIN     3000.       360
RE FINISHED

ME STARTING
ME INPUTFIL C:\MET\PBIPBI87.MET
ME ANEMHGHT    33  FEET
ME SURFDATA  12844      1987    WEST-PALM-BCH
ME UAIRDATA  12844      1987    WEST-PALM-BCH
ME FINISHED

OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
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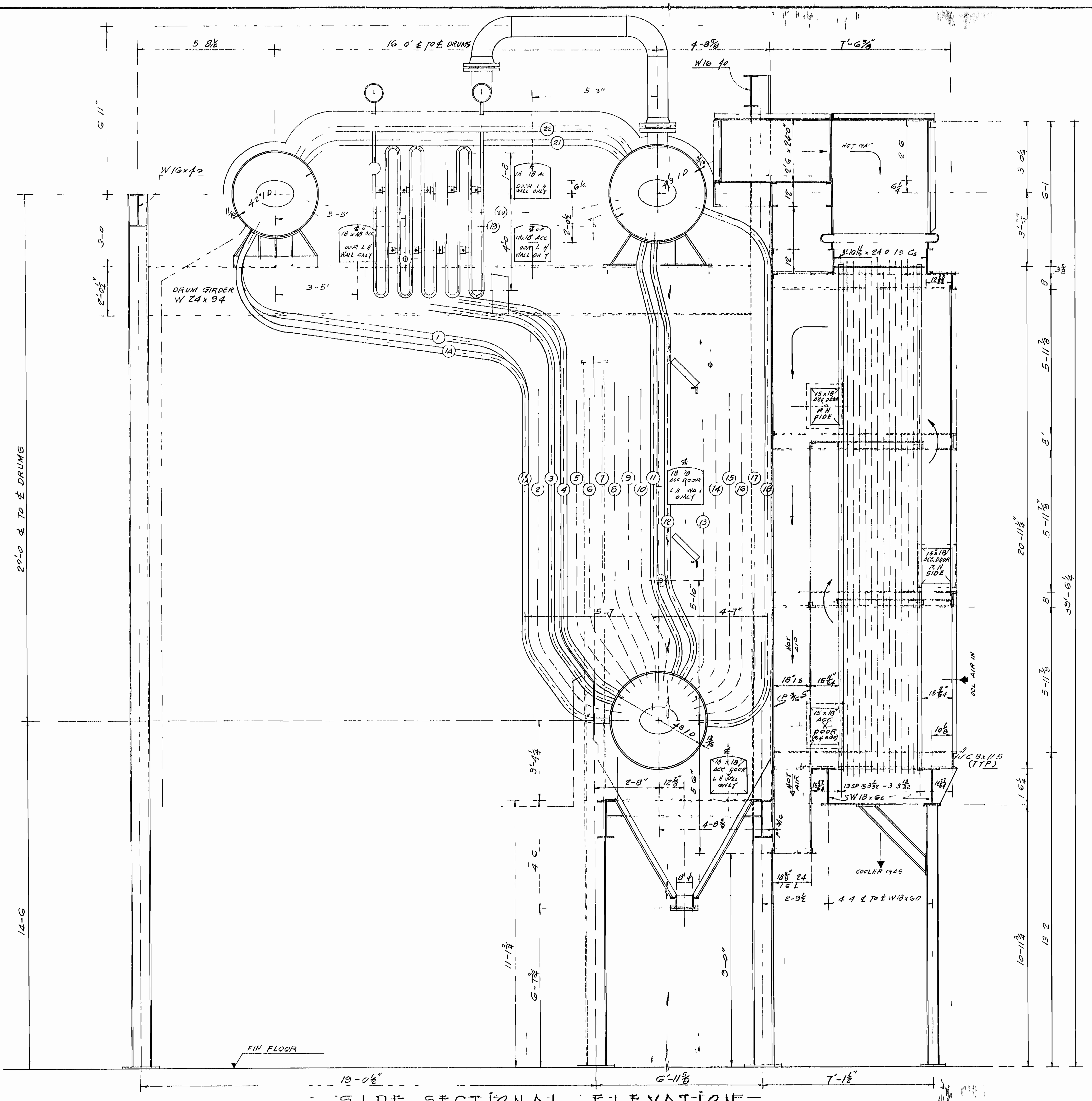
APPENDIX I

BOILER NOS. 4 AND 5 DRAWINGS


0990019-006
NUMBER OF BOILERS WANTED ONE
CAPACITY 125,000 # STEAM PER HR
DESIGN PRESSURE 250 PSI
OPERATING " 175 PSI
HEATING SURFACE - BOILER 18,000 SQ FT
- AIR PREHEATER 15393 SQ FT
CODE REQUIRED A.S.M.E.
FUEL = BAGASSE
(N) MEANS NOT FURNISHED BY THE BIGELOW CO
BOILER SETTING (N)
WEIGHT OF WATER - BOILER FULL 123000 #
SEE DR NO LH3F 484 2 FOR ORIGIN OF SECTION.
SIDE SECTIONAL ELEVATION AT AA
PARTIAL REAR VIEW
BOILER No. 4
THE BIGELOW CO
NEW HAVEN CONN U S A
RETURNED UPON REQUEST
SIDE ELEVATION OF 125,000#/HR BIGELOW
TYPE "F 48 WATER TUBE BOILER
FOR-BIGELOW-LIPTAK CORP-DETROIT, MICHIGAN
FOR-OSCEOLA FARMS CO., INC. - PALM BEACH
VERMILION SUGAR FACTORY-PAHOKEE
DATE APRIL 23 65
JOB NO. 3370
FILE NO.
SCALE 1/2"=1-0"
DRAWN BY CJW
CHECKED BY
DRWG NO. LH3F-484-18
A STEAM OUTLET WAS 10" DIA.
B ADDED SUPERHEATER AND STEAM PURIFIERS, REVISED S.B. ELEMENT "A" BLOWING ARC, OPERATING PRESSURE WAS 150#

2
10¾ OD HEADERS
(38)-1¾ O.D. x 120 TK ELEMENTS
11 UNIT SPC'S @ 12" = 11'-0"
24 0 FURN WIDTH
25 0 TL-TL LOWER DRUM
22 7¼" x 5-11⅝ I.S. C - AIR INLET
TUBE REMOVAL PANL FOR AIR PREHEATER
24 0" DUCT B/ T.B. CO
(1)-ANDERSON BT 10 STEAM PURIFIER
8 DIA STEAM LEAD
8 DIA STEAM LEAD
10¾ OD INLET HEADER
10¾ OD OUTLET HEADER
15'6 ℄-℄ STEAM LEADS
24 0 FURN WIDTH
3⅞ DIA MASTER H.H.
3⅞ DIA MASTER H.H.
1 DIA U-BOLTS
4-13# WF (4 PLACES)
℄ BOILER & AIR PREHEATER
26 6" ℄-℄ COL'S
WATER COL EITHER SIDE
FLOOR LINE
Boiler No. 4
HALF FRONT SECTION AT "C-C"
HALF FRONT SECTION AT "B-B"
PLAN VIEW
SEE DR NO LH3F-481-4 FOR ORIGIN OF SECTIONS
(N) MEANS NOT FURNISHED BY THE BIGELOW CO.
THIS DRAWING IS THE PROPERTY OF THE BIGELOW CO. NEW HAVEN CONN U.S.A.
FRONT SECTIONAL VIEWS & PLAN VIEW OF 125000#/HR BIGELOW TYPE "F" 48 W.T. BOILER
FOR BIGELOW LIPTAK CORP. - DETROIT, MICHIGAN
FOR OSCEOLA FARMS CO. INC. - PALM BEACH, FLA.
VERMILION SUGAR FACTORY - PAHOKEE, FLA.
DATE APRIL 21 65
JOB NO. 13370
DRAWN BY CJW
CHECKED BY
SCALE ½"=1'0"
DRWG. NO. LH3F-484-2B
B ADDED SUPERHEATER AND STEAM PURIFIERS



OSCEOLA FARMS COMPANY
SUGAR FACTORY

SCALE 1/2 = 1-0" | BY J H FARIÑAS | DRAWN Y.A APARICIO
DATE SEP.22/03 | BY ED F FARIÑAS

SIDE SECTIONAL ELEVATION
MODIFICATION

BOILER No 5 | DRAWING NUMBER 3-1693