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BUREAU OF AIR REGULATION

PSD PERMIT APPLICATION
FOR
ATLANTIC SUGAR ASSOCIATION
BOILER NO. 5

Prepared For:

Atlantic Sugar Association
Belle Glade, Florida

Prepared By:

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

October 1999
9937584Y/F1

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PART A

PERMIT APPLICATION

Department of
Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Atlantic Sugar Association, Inc.**	
2. Site Name: **Atlantic Sugar**	
3. Facility Identification Number: **0990016** [ ] Unknown	
4. Facility Location: Street Address or Other Locator: **SR 880-16 miles East of Belle Glade** City: **Belle Glade** County: **Palm Beach** Zip Code: **33430**	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **Hector J. Cardentey, Assistant Vice President, Env. Dir.**
2. Application Contact Mailing Address: Organization/Firm: **Atlantic Sugar Association, Inc.** Street Address: **P.O. Box 1570** City: **Belle Glade** State: **FL** Zip Code: **33430**
3. Application Contact Telephone Numbers: Telephone: (**561**) **996 - 6541** Fax: (**561**) **996 - 8021**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	October 26, 1999
2. Permit Number:	0990016-004-AC
3. PSD Number (if applicable):	PSD-FL-279
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number:_____

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

Current construction permit number:_____

Operation permit number to be revised:_____

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

Operation permit number to be revised/corrected:_____

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

Operation permit number to be revised:_____

Reason for revision:_____

Air Construction Permit Application

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

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

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

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

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official:
   John A. Fanjul, Vice President and General Manager
2. Owner/Authorized Representative or Responsible Official Mailing Address:
   Organization/Firm: **Atlantic Sugar Association, Inc.**
   Street Address: **SR 880-16 mi E of Belle Glade**
   City: **Belle Glade** State: **FL** Zip Code: **33430**
3. Owner/Authorized Representative or Responsible Official Telephone Numbers:
   Telephone: (**561**) **996 - 6541** Fax: (**561**) **996 - 8021**
4. Owner/Authorized Representative or Responsible Official Statement:

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

Signature

Oct. 21/99
Date

* Attach letter of authorization if not currently on file.

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: **32653-1500**
3. Professional Engineer Telephone Numbers:
   Telephone: (**352**) **336 - 5600** Fax: (**352**) **336 - 6603**

4. Professional Engineer Statement:

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

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

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

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

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

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

David A. Buff — Signature

10/20/99 — Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
1R	Boiler No. 5	AC1D	7,500

Application Processing Fee

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

Construction/Modification Information

1. Description of Proposed Project or Alterations:

Increase maximum annual heat input for Boiler No. 5 from 0.678×10^{12} Btu/yr to 0.867302×10^{12} Btu/yr with no restriction on operation hours.

2. Projected or Actual Date of Commencement of Construction: **1 Jan 2000**

3. Projected Date of Completion of Construction: **1 Jan 2000**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17** East (km): **552.902** North (km): **2945.207**			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **26 / 37 / 43** Longitude (DD/MM/SS): **80 / 28 / 7**			
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 (limit to 500 characters): **Operations involve raw sugar manufacture from sugar cane. Based on historical agricultural crop seasons, up to a peak of 17,000 tons of cane can be processed a day (see facility flow diagram; Attachment ASA-FE-3). Operating rate will vary from season to season depending on agricultural, market, and weather conditions.**			

Facility Contact

1. Name and Title of Facility Contact: **Hector J. Cardentey, Assistant Vice President, Env. Dir.**
2. Facility Contact Mailing Address: Organization/Firm: **Atlantic Sugar Association, Inc.** Street Address: **P.O. Box 1570** City: **Belle Glade** State: **FL** Zip Code: **33430**
3. Facility Contact Telephone Numbers: Telephone: (**561**) **996** - **6541** Fax: (**561**) **996** - **8021**

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [ ] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [ ] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): **Emission factors for HAPs from bagasse boilers are not currently available. Future testing may indicate the facility is a major source of HAPs.**	

List of Applicable Regulations

Only those rules, regulations & ordinances specifically identified herein apply to this facility.	
Title V Core List, effective date 3/25/97	

Title V Core List

Effective: 03/25/97

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

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

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

Federal: ***(description)***

40 CFR 61: National Emission Standards for Hazardous Air Pollutants (NESHAP)
40 CFR 61, Subpart M: NESHAP for Asbestos.

40 CFR 82: Protection of Stratospheric Ozone.
40 CFR 82, Subpart B: Servicing of Motor Vehicle Air Conditioners (MVAC).
40 CFR 82, Subpart F: Recycling and Emissions Reduction.

State: ***(description)***

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

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

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

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

Title V Core List

Effective: 03/25/97

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

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

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

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

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

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

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

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

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

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

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

Title V Core List

Effective: 03/25/97

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

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

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

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

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

Identification of Additional Applicable Requirements

Applicable Requirements, as defined in Rule 62-210.200(29), but not identified in the attached Core List, are included in this attachment entitled "**Identification of Additional Applicable Requirements**". Only those rules, regulations, and ordinances specifically identified on the Title V Core List (effective date 3/25/97) or herein, apply to this facility.

FACILITY

State

62-210.700(1), F.A.C.:	Excess Emissions
62-210.700(4), F.A.C.:	Excess Emissions
62-210.700(6), F.A.C.:	Excess Emissions
62-256.300, F.A.C.:	Open Burning - Prohibitions
62-256.400, F.A.C.:	Open Burning - Agricultural and Silvicultural Fires
62-256.500, F.A.C.:	Open Burning - Land Clearing
62-256.600, F.A.C.:	Open Burning - Industrial, Commercial, Municipal and Research Open Burning
62-296.320(4)(b), F.A.C.:	General VE Standards

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
PM	A				Particulate Matter-Total
PM_{10}	A				Particulate Matter-PM_{10}
SO_2	A				Sulfur Dioxide
NO_x	A				Nitrogen Oxides
CO	A				Carbon Monoxides
VOC	A				Volatile Organic Compounds

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location:
   [X] Attached, Document ID: **ASA-FE-1** [ ] Not Applicable [ ] Waiver Requested

2. Facility Plot Plan:
   [X] Attached, Document ID: **ASA-FE-2** [ ] Not Applicable [ ] Waiver Requested

3. Process Flow Diagram(s):
   [X] Attached, Document ID: **ASA-FE-3** [ ] Not Applicable [ ] Waiver Requested

4. Precautions to Prevent Emissions of Unconfined Particulate Matter:
   [ ] Attached, Document ID: _____ [X] Not Applicable [ ] Waiver Requested

5. Fugitive Emissions Identification:
   [X] Attached, Document ID: **See PSD Report**
   [ ] Not Applicable [ ] Waiver Requested

6. Supplemental Information for Construction Permit Application:
   [X] Attached, Document ID: **See PSD Report** [ ] Not Applicable

7. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities:
   [ ] Attached, Document ID:_____ [ ] Not Applicable

9. List of Equipment/Activities Regulated under Title VI:
   [ ] Attached, Document ID:_____
   [ ] Equipment/Activities On site but Not Required to be Individually Listed
   [ ] Not Applicable

10. Alternative Methods of Operation:
    [ ] Attached, Document ID:_____ [ ] Not Applicable

11. Alternative Modes of Operation (Emissions Trading):
    [ ] Attached, Document ID:_____ [ ] Not Applicable

12. Identification of Additional Applicable Requirements:
    [ ] Attached, Document ID:_____ [ ] Not Applicable

13. Risk Management Plan Verification:
    [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:_____) or previously submitted to DEP (Date and DEP Office:_____)
    [ ] Plan to be submitted to CEPPO (Date required:_____)
    [ ] Not Applicable

14. Compliance Report and Plan:
    [ ] Attached, Document ID:_____ [ ] Not Applicable

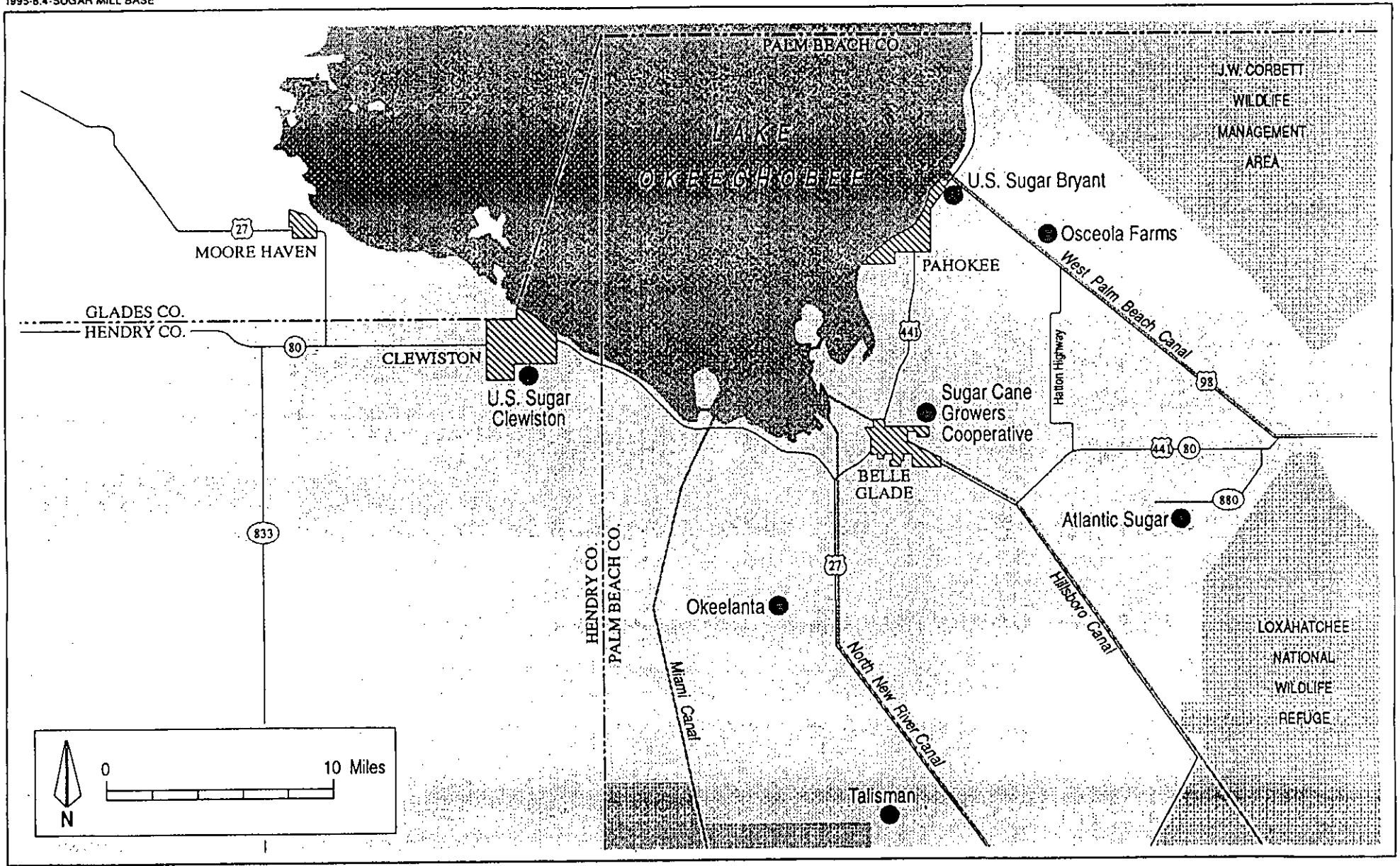
15. Compliance Certification (Hard-copy Required):
    [ ] Attached, Document ID:_____ [ ] Not Applicable

ATTACHMENT ASA-FE-1

AREA MAP

1995-8.4-SUGAR MILL BASE

08-25-95



Attachment ASA-FE-1
Location of Florida Sugar Mills

Source: KBN, 1995.

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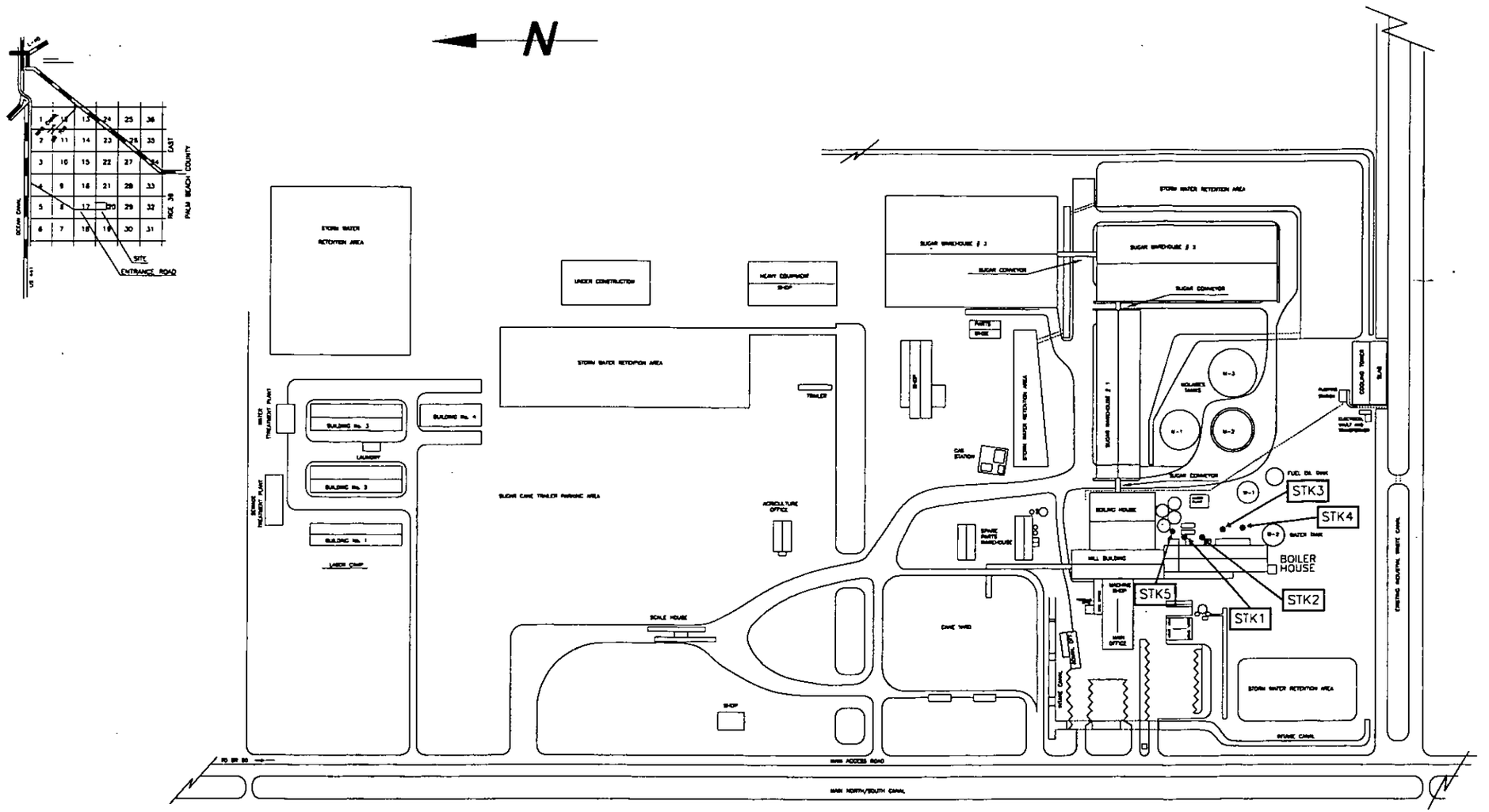
ATTACHMENT ASA-FE-2

FACILITY PLOT PLAN

Note: Plot plan for genenral information, not to scale.



Attachment ASA–FE–2: Facility Plot Plan

Atlantic Sugar Association, Inc. Belle Glade, FL	Emission Unit Identification	Filename: atlplot.dwg Latest Revision: 10/11/99

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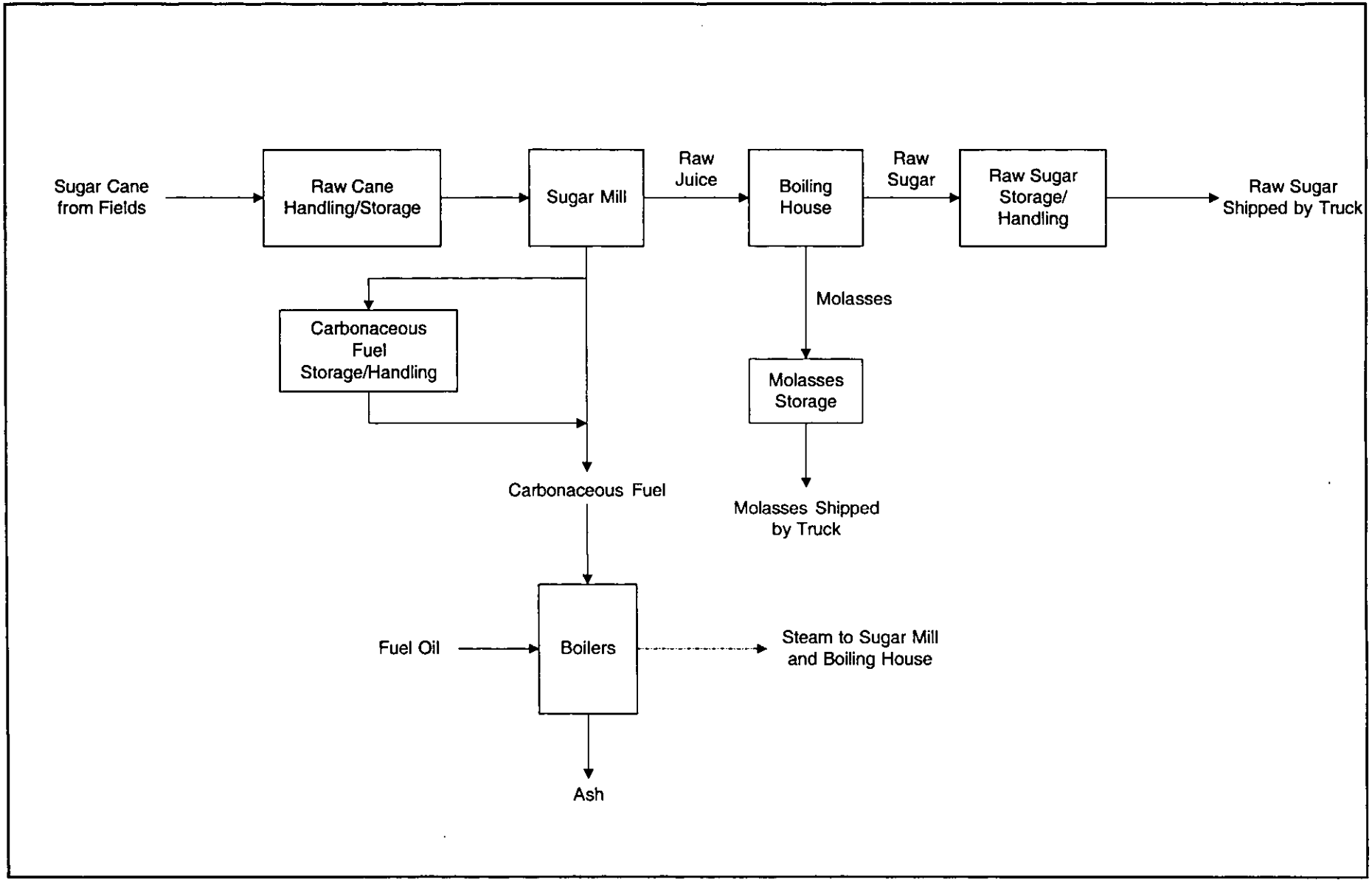
ATTACHMENT ASA-FE-3

PROCESS FLOW DIAGRAM



Attachment ASA-FE-3
Sugar Manufacturing
Process Flow Diagram
Atlantic Sugar Association
Belle Glade, FL

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

Facility Flow Diagram

Filename: GENATL.VSD

Date: 10/19/99

Golder Associates

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Boiler No. 5

4. Emissions Unit Identification Number:
ID: **005**
[ ] No ID
[ ] ID Unknown

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

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

Traveling grate boiler with an economizer fired by carbonaceous fuel (bagasse, wood chips, rice hulls) and No. 6 residual fuel oil.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

One Joy Type Turbulaire wet impingement scrubber, Type D.

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

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:	
2. Generator Nameplate Rating:	MW	
3. Incinerator Information:		
Dwell Temperature:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		**255.3**	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:	**130,000 lb/hr of steam**		
5. Requested Maximum Operating Schedule:			
	24 hours/day		**7** days/week
	52 weeks/year		**8,760** hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Max heat input based on max 1-hr avg. heat input from carbonaceous fuel. Maximum heat input for No. 6 oil is 70.5 MMBtu/hr. Max production is max 1-hr avg steam rate at 250 psi/550°F from permit cond.

C. 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(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)10.: 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(8): General Compliance Test Requirements
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
62-297.401(25): EPA Test Method 25
62-297.401(5): EPA Test Method 5
62-297.401(6)(a): EPA Test Method 6a
62-297.401(6)(b): EPA Test Method 6b
62-297.401(6): EPA Test Method 6
62-297.401(7)(a): EPA Test Method 7a
62-297.401(7)(e): EPA Test Method 7e
62-297.401(7): EPA Test Method 7
62-297.401(9): EPA Test Method 9
62-297.440(1)(b): Supplemental Test Procedures

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **BLR 5**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **90** feet	7. Exit Diameter: **5.5** feet
8. Exit Temperature: **150** °F	9. Actual Volumetric Flow Rate: **90,000** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone: East (km): North (km):		
14. Emission Point Comment (limit to 200 characters): **Stack parameters based on stack test data.**		

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

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **External combustion boilers, industrial bagasse, all boiler sizes**		
2. Source Classification Code (SCC): **1-02-011-01**	3. SCC Units: **Tons burned**	
4. Maximum Hourly Rate: **35.458**	5. Maximum Annual Rate: **120,459**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **7**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 7.2 (rounded to 7). Max rates based on 255.3 MMBtu/hr and 867,302 MMBtu/yr and a wet bagasse heating value of 3,600 Btu/lb.**		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **External combustion boilers, industrial, wood/bark waste, wood-fired boilers (>50,000 lbs steam).**		
2. Source Classification Code (SCC): **1-02-009-03**	3. SCC Units: **Tons burned**	
4. Maximum Hourly Rate: **25.53**	5. Maximum Annual Rate: **86,730**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **10**
10. Segment Comment (limit to 200 characters): **Max rates based on 255.3 MMBtu/hr and a wood chip heating value of 5,000 Btu/lb. Includes up to 5.0 Tons/hr (61.2 MMBtu/hr; heating value of 6,200 Btu/lb) max from rice hull combustion.**		

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

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **External combustion boilers, industrial, residual oil, grade 6 oil.**		
2. Source Classification Code (SCC): **1-02-004-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **0.470**	5. Maximum Annual Rate: **500**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.7**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
10. Segment Comment (limit to 200 characters): **Max rates based on 70.5 MMBtu/hr and 0.7% sulfur (max permitted % S content) No. 6 fuel oil.**		

Segment Description and Rate: Segment ____ of ____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	002		EL
PM_{10}	002		NS
SO_2	002		EL
NO_X			EL
CO			EL
VOC			EL

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **38.3** lb/hour **65.0** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: **0.15 lb/MMBtu** Reference: **Permit Limit**	7. Emissions Method Code: **0**

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

255.3 MMBtu/hr x 0.15 lb/MMBtu = 38.3 lb/hr.
867,302 MMBtu/yr x 0.15 lb/MMBtu x tons/2000 lb = 65.0 TPY.

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

Max emissions based on carbonaceous fuel firing.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.15 lb/MMBtu**	4. Equivalent Allowable Emissions: **38.3** lb/hour **65.0** tons/year

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

EPA Method 5

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

PM from carbonaceous heat input up to 255.3 MMBtu/hr. Rule 62-296.410(2)(b), FAC. Max hourly emissions representative of a permit condition.

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **7.05** lb/hour **3.75** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 5**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **PM from No. 6 residual fuel oil heat input up to 70.5 MMBtu/hr and 75,000 MMBtu/yr.**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.15 lb/MMBtu**	4. Equivalent Allowable Emissions: **38.3** lb/hour **65.0** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 5**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on carbonaceous fuel and fuel oil firing. Emission factor given is for carbonaceous fuel firing.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **35.7** lb/hour **60.7** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: **0.14 lb/MMBtu** Reference: **Permit Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **255.3 MMBtu/hr x 0.14 = 35.7 lb/hr. 0.867 x 10^{12} Btu/yr x 0.14 lb/MMBtu x 1 ton/2000 lb = 60.7 TPY.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max emission based on carbonaceous fuel firing.**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **66.7** lb/hour **67.0** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: **0.73 lb/MMBtu** Reference: **Permit limit for oil**	7. Emissions Method Code: **0**

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

(152.7 MMBtu/hr x 0.10 lb/MMBtu) + (70.5 MMBtu/hr x 0.73 lb/MMBtu) = 66.7 lb/hr.
((0.867 x 10^{12} Btu/yr - 75000 x 10^{6} Btu/yr) x 0.10 lb/MMBtu + (75000 x 10^{6} x 0.73 lb/MMBtu) x tons/2000 lb = 67.0 TPY.

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

Max emissions based on carbonaceous fuel and fuel oil firing. Emission factor given is for fuel oil firing.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.10 lb/MMBtu**	4. Equivalent Allowable Emissions: **25.5** lb/hour **43.4** tons/year

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

EPA Method 6, 6A, 6B

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

SO_2 from carbonaceous heat input up to 255.3 MMBtu/hr and 0.867 x 10^{12} Btu/yr.

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.73 lb/MMBtu**	4. Equivalent Allowable Emissions: **51.5** lb/hour **27.4** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel oil analysis**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **SO_2 from No. 6 fuel oil heat input up to 255.3 MMBtu/hr and 75,000 MMBtu/yr(500,000 gal/yr).**	

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

Potential/Fugitive Emissions

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

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: **66.7** lb/hour **67.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel oil analysis and stack testing**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Combination of bagasse and fuel oil analysis.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_X**	2. Total Percent Efficiency of Control:

3. Potential Emissions: **63.8** lb/hour **110.7** tons/year	4. Synthetically Limited? [X]

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

6. Emission Factor: **0.31 lb/MMBtu** Reference: **AP-42 factor**	7. Emissions Method Code: **0**

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

255.3 MMBtu/hr x 0.25 lb/MMBtu = 63.8 lb/hr
((0.867 x 10^{12} Btu/yr - 75000 x 10^{6} Btu/yr) x 0.25 lb/MMBtu) + (75000 x 10^{6} Btu/hr x 0.31 lb/MMBtu) x ton/2000 lb = 110.7 TPY.

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

Max emissions based on carbonaceous fuel and fuel oil firing. Emission factor given is for fuel oil firing.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.25 lb/MMBtu**	4. Equivalent Allowable Emissions: **63.8** lb/hour **110.7** tons/year

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

EPA Method 7, 7A, 7E

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

NO_X from carbonaceous heat input up to 255.3 MMBtu/hr and 0.867 x 10^{12} Btu/yr.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1,660** lb/hour **2,819** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: **6.5 lb/MMBtu** Reference: **Permit limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **255.3 MMBtu/hr x 6.5 lb/MMBtu = 1,660 lb/hr** **0.867 x 10^{12} Btu/yr x 6.5 lb/MMBtu = 2,819 ton/year**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max emissions are based on carbonaceous fuel firing. Emission factor based on carbonaceous fuel.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **6.5 lb/MMBtu**	4. Equivalent Allowable Emissions: **1,660** lb/hour **2,819** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **CO from carbonaceous heat input up to 255.3 MMBtu/hr and 0.867 x 10^{12} Btu/yr.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:

3. Potential Emissions: **127** lb/hour **216.8** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: **0.5 lb/MMBtu** Reference: **Permit limit**	7. Emissions Method Code: **0**

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

255.3 MMBtu/hr x 0.15 lb/MMBtu = 127.7
0.867 x 10^{12} Btu/yr x 0.5 lb/MMBtu = 216.8 tons/year

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

Max emissions are based on carbonaceous fuel firing. Emission factor given is for carbonaceous fuel firing.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.50 lb/MMBtu**	4. Equivalent Allowable Emissions: **127** lb/hour **216.8** tons/year

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

EPA Method 18, 25, 25A (modified)

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

VOC from carbonaceous heat input up to 255.3 MMBtu/hr and 0.867 x 10^{10} Btu/yr.

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE30**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **30 %** Exceptional Conditions: **40 %** Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **See VE Comment**	
5. Visible Emissions Comment (limit to 200 characters): **Rule 62-296.410(2)(b) FAC. However, the VE limit shall not be applicble if the plume cannot be read due to moisture condensation.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 7

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: **Brooks** Model Number: **BA31, Birotor** Serial Number: **See Comment**	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Existing permit condition requires monitoring of oil flow. No serial no. or installation date provided because meters are routinely replaced to ensure optimum performance.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **Existing perm. cond. related to bagasse handling sys. VE limit shall not apply when winds exceed 18 MPH, if reasonable precautions to control fugitive emissions have been taken.**	

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

Continuous Monitoring System: Continuous Monitor 2 of 7

1. Parameter Code: **PRS**	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: **Custom Design** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Existing permit condition requires monitoring of scrubber pressure drop. Parameter monitored to ensure proper operation of the scrubber.**	

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

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

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

Continuous Monitoring System: Continuous Monitor 3 of 7

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: **Custom Design** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Existing permit condition requires monitoring of scrubber inlet water pressure. Parameter monitored to ensure proper operation of the scrubber.**	

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

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

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

Continuous Monitoring System: Continuous Monitor 4 of 7

1. Parameter Code: FLOW	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: Custom Design Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): Existing permit condition requires monitoring of scrubber water flow. Parameter monitored to ensure proper operation of the scrubber.	

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

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

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

Continuous Monitoring System: Continuous Monitor 5 of 7

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: **Fisher and Porter** Model Number: **51-1102 WC/N** Serial Number: **See Comment**	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Existing permit condition requires monitoring of steam production. No serial number or installation date provided because meters are routinely replaced to ensure optimum performance.**	

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

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

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

Continuous Monitoring System: Continuous Monitor 6 of 7

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: **Fisher and Porter** Model Number: **51-11029/T02** Serial Number: **See Comment**	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Existing permit condition requires monitoring of steam pressure. No serial number or installation date provided because meters are routinely replaced to ensure optimum performance.**	

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

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

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

Continuous Monitoring System: Continuous Monitor 7 of 7

1. Parameter Code: **TEMP**	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: **Fisher and Porter** Model Number: **51-11029/T02** Serial Number: **See Comment**	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Existing permit condition requires monitoring of steam temperature. No serial number or installation date provided because meters are routinely replaced to ensure optimum performance.**	

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: ASA-EU1-L1 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: ASA-EU1-L2 [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: ASA-EU1-L3 [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:_____ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:_____ [ ] Previously submitted, Date:_____ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:_____ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:_____ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: See PSD Report [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:_____ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

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

13. Identification of Additional Applicable Requirements
[ ] Attached, Document ID:_____ [ ] Not Applicable

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

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

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

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

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

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

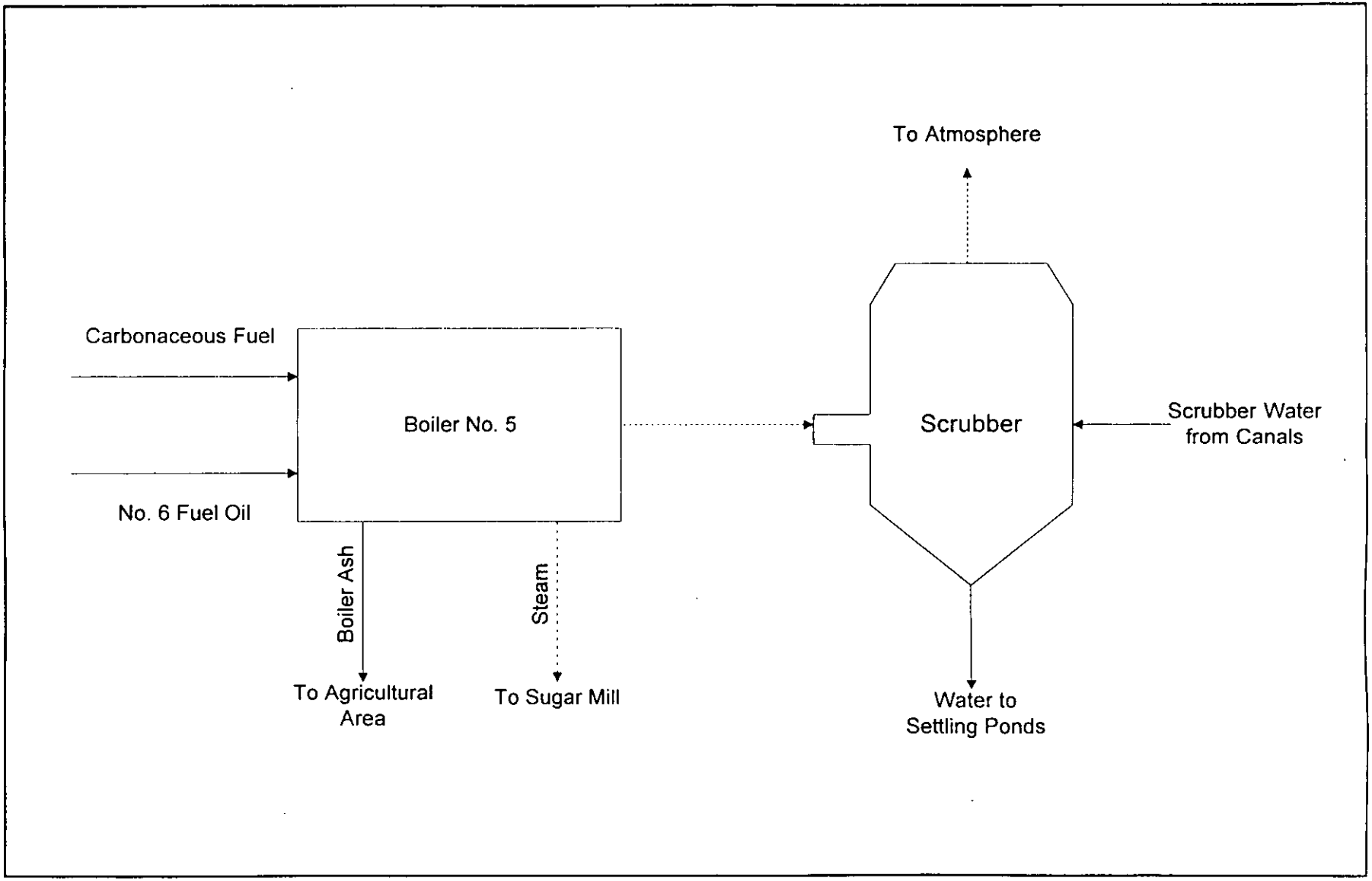
[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID:_____

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

[ ] Not Applicable

ATTACHMENT ASA-EU1-L1

PROCESS FLOW DIAGRAM



Attachment ASA-EU1-L1 Boiler No. 5 Process Flow diagram Atlantic Sugar Association Belle Glade, FL	**Process Flow Legend** Solid/Liquid ——► Gas ·····► Steam ·····►	Boiler No. 5 Filename: ATBLR5.VSD Date: 04/17/96	Golder Associates

ATTACHMENT ASA-EU1-L2

FUEL ANALYSIS OR SPECIFICATION

Attachment ASA-EU1-L2
Fuel Analysis Specification for Atlantic Sugar Association Boiler No. 5

Parameter	Carbonaceous Fuel			No. 6 Fuel Oil (d) (0.7% max S)
	Bagasse (a)	Wood Waste (b)	Rice Hulls(c)	
Density (lb/gal)	--	--	--	7.94
Approximate Heating Value (Btu/lb) (e)	3,600	5,000	6,200	18,892
Approximate Heating Value (Btu/gal)	--	--	--	150,000
Ultimate Analysis (dry basis):				
Carbon	48.48%	47.32%	39.2%	87.3%
Hydrogen	6.01%	5.62%	4.7%	10.5%
Nitrogen	0.33%	0.33%	1.45%	0.28%
Oxygen	43.65%	39.67%	33.25%	0.64%
Sulfur	0.05%	0.12%	0.2%	0.7%
Ash/Inorganic	1.44%	7.01%	21.2%	0.04%
Moisture	52%	37%	17.7%	--

Note: All values represent average fuel characteristics.

Footnotes:
(a) Source: sugar industry fuel analysis averages.
(b) Source: average of wood chip analysis (57 separate lots) from Okeelanta Corporation.
(c) Laboratory analysis performed for Atlantic Sugar Association by D.B. Riley, Inc.
(d) Source: Perry's Chemical Engineers' Handbook. Sixth Edition.
(e) Average values on a wet basis for bagasse, wood chips, and rice hulls.

ATTACHMENT ASA-EU1-L3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

Attachment ASA-EU1-L3

Control Equipment Parameters and Particulate Removal Efficiency Derivation for Boiler No. 5
Wet Collection System at Atlantic Sugar Mill

Boiler No. 5 52FTM50001605		
Manufacturer and Model No.	1 Joy Type Turbulaire Wet Impingement Scrubber Type-D	
Outlet Gas Temp (F)	150	(a)
Outlet Gas Flow Rate (ACFM)	90,000	(a)
Pressure Drop Across Device (inches of H2O) Min/Max	5 / 10	(b)
Scrubbant Flow Rate (gal/min) - Minimum	550	(b)
Scrubbant Supply Pressure (psi) - Min/Max	35 / 60	(b)
Average Scrubbant pH Min/Max	6 / 8.5	
Max Permitted Heat Inputs (MMBtu/hr) : Carbonaceous fuel	255.3	
Max Carbonaceous fuel Consumption (lb carbonaceous fuel/hr)	70,917	(c)
Uncontrolled Particulate Emission Rate (lb particulates/ton carbonaceous fuel)	15.6	(d)
Permitted Particulate Emission Rate (lb particulates/MMBtu)	0.15	(b)

Pollutants

	Inlet Loading ^(lb/hr)	Outlet Loading (lb/hr)	Control Efficiency (%)
Particulate Matter	553.2	38	93

Note: Scrubber parameters represent typical values.

(a) Average values obtained from stack test data.
(b) From permit specific condition.
(c) calculated using an average bagasse heating value of 3,600 btu/lb and the permitted heat input rate.
(d) AP-42 table 1.8-2 uncontrolled emission factor of 15.6 lb/ton.

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

PART B

PSD REPORT

1.0 INTRODUCTION AND EXECUTIVE SUMMARY

Atlantic Sugar Association (ASA) is proposing a modification to its sugar mill located near Belle Glade, Palm Beach County, Florida. The proposed modifications to Boiler No. 5 consist of increases in the permitted operating hours and the annual steam production and heat input rates.

Boiler No. 5 is permitted to produce 130,000 lb/hr steam, and 115,000 lb/hr steam as a daily average. Boiler No. 5 fires bagasse as its primary fuel, with No. 6 fuel oil as backup. It is currently permitted to operate up to 3,000 hours per year, and only during the sugar processing season. Historically, the permitted number of operating hours have been sufficient to meet needs of the ASA sugar mill. Due to a number of factors, including recent shutdown of the Talisman sugar mill as part of the Everglades cleanup settlement, the length of the sugar processing season may increase in the future. As a result, ASA desires to increase the permitted operation of the boiler to an equivalent of 160 days per year (3,840 hr/yr) at the maximum 24-hr steam rate. However, ASA desires the flexibility to operate the boiler at any time throughout the year, and therefore is requesting maximum operating hours of 8,760 hr/yr.

ASA made application and was issued a U.S. Environmental Protection Agency (EPA) prevention of significant deterioration (PSD) permit in 1981. The permit was modified in 1986, and the boiler currently operates under permit AO50-205996, issued March 12, 1992.

Modifications to the operation of Boiler No. 5, described in this application, will result in potential emissions that will exceed current permit limits and will require a PSD review. This application contains the technical information developed in accordance with PSD regulations as promulgated by the EPA and implemented through delegation to the Florida Department of Environmental Protection (FDEP). It presents an evaluation of regulated pollutants subject to PSD review, a demonstration of Best Available control Technology (BACT), and an assessment of potential air quality impacts associated with the project. Through this application, ASA requests that the FDEP issue a PSD construction permit for this project.

1.1 PREVENTION OF SIGNIFICANT DETERIORATION (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 delegation to the FDEP. FDEP has adopted the EPA PSD regulation as Rule 62-212.400, Florida Administrative Code (F.A.C.).

The current actual emissions, maximum future emissions, and the net increase in emissions, all in tons per year (TPY), associated with this project are presented 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:

- Particulate Matter (PM) as total suspended particulate matter (TSP),
- Particulate Matter with aerodynamic diameter of 10 microns or less (PM_{10}),
- Nitrogen dioxide (NO_2),
- Sulfur dioxide (SO_2),
- Carbon monoxide (CO), and
- Volatile Organic Compounds (VOC).

Palm Beach County has been designated as an attainment or maintenance area for all criteria pollutants. The county is also classified as a PSD Class II area for PM_{10}, SO_2, and NO_2. As a result, the new source review will follow PSD regulations pertaining to such designations. Other regulated pollutants will be emitted in insignificant amounts.

1.2 BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

For the proposed modification to Boiler No. 5, a BACT analysis was conducted for each pollutant for which the net increase exceeds the EPA/FDEP significance threshold and, is therefore, subject to BACT review. The proposed BACT to control PM/PM_{10} emissions from Boiler No. 5 is the existing wet scrubber control technology which limits emissions to 0.15 pounds per million British thermal units (lb/MMBtu) of heat input to the boiler. Evaluation

of an electrostatic precipitator (ESP) for particulate control was ruled out due to economic infeasibility. NO_x, CO and VOC emissions will be controlled by good combustion practices. SO_2 emissions are controlled by the inherent low sulfur content of bagasse fuel and by limiting the sulfur content of No. 6 fuel oil, as well as limiting total annual fuel oil usage for Boiler No. 5. The proposed BACT is replacement of any oil burned in Boiler No. 5 during the year with 0.7 percent sulfur fuel oil into the common fuel oil storage tank.

1.3 AIR QUALITY ANALYSIS

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

1.4 SUMMARY OF ANALYSIS

Results from the analyses presented in this PSD Air Permit application, lead to the following conclusions:

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

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

1.5 AIR PERMIT APPLICATION ORGANIZATION

This air permit application is divided into seven 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 PSD and nonattainment requirements applicable to the proposed project;
- Section 4.0 presents the ambient air monitoring analysis (pre-construction monitoring) required by PSD regulations;
- Section 5.0 includes the control technology review and BACT analysis;
- Section 6.0 presents 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;
- Section 7.0 provides the additional impact analyses for soils, vegetation, and visibility, as well as the AQRV analysis for the PSD Class I area.

Table 1-1. Net Emissions Increase for Belle Glade Atlantic Sugar Boiler No. 5

Pollutant	PSD Baseline Emissions (TPY)	Future Maximum Emissions (TPY)	Net Increase in Emissions (TPY)	PSD Significant Rate (TPY)	PSD Review Applies?
Particulate Matter (PM)	29.0	65.0	36.0	25	Yes
PM10	26.6	60.7	34.1	15	Yes
Sulfur Dioxide	0.5	67.0	66.5	40	Yes
Nitrogen Oxides	34.9	110.7	75.8	40	Yes
Carbon Monoxide	777.0	2,818.7	2,041.7	100	Yes
Volatile Organic Compounds	36.3	216.8	180.5	40	Yes
Sulfuric Acid Mist	0.03	4.1	4.1	7.0	No
Lead	0.11	0.19	0.09	0.60	No
Mercury	9.20E-03	1.65E-02	7.28E-03	0.10	No
Beryllium	0	6.94E-06	6.94E-06	4.00E-04	No

2.0 PROJECT DESCRIPTION

2.1 SITE DESCRIPTION

The ASA sugar mill receives sugar cane 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 where the sugar cane juices are squeezed from the cane. The fibrous byproduct material is called bagasse and is burned in onsite 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. Steam is used in the raw sugar production process. Raw sugar is shipped offsite to customers. Refer to Attachment ASA-FE-3 of the permit application form for a flow diagram of the overall sugar production process.

The ASA mill consists of five bagasse/oil-fired boilers (Boiler Nos. 1, 2, 3, 4, and 5), which provide steam to the sugar mill. The primary fuel for all boilers is bagasse, while 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 at ASA have wet scrubbers for particulate matter control. Currently, Boiler Nos. 1 through 4 have a permit limitation on annual operating hours. Boiler Nos. 1 through 4 operations are limited to 4,368 hr/yr per calendar year. Boiler No. 5 operation is limited to 3,000 hours per season.

2.2 BOILER NO. 5

Boiler No. 5 is currently operating under Permit No. A050-205996, DEP issued March 12, 1992 (copy attached in Appendix A). The boiler is permitted to operate while combusting carbonaceous (bagasse) fuel alone at a maximum 1-hr heat input rate of 252.65 MMBtu/hr, and at maximum steam rates of 130,000 lb/hr (1-hr average) and 115,000 lb/hr (24-hr average) at 550°F and 250 psig.

Historically, Boiler No. 5 has been operated at or near permitted steam rates. Past compliance tests spanning the last 5 years have been performed at steam rates ranging from 95,700 lb/hr steam up to 126,800 lb/hr steam.

Boiler No. 5 has two fuel oil burners, each with a capacity of 235 gal/hr (approximately 35.25 MMBtu/hr). By permit restriction, No. 6 fuel oil can be combusted at a maximum of 168 gallons per hour (gal/hr). No. 6 fuel oil burned in the boiler must be replaced, during the season it is burned, with an equal amount in the common fuel oil storage tank for Boiler Nos. 1 through 5. The replacement fuel oil cannot contain more than 1.0 percent sulfur by weight. Since the common fuel oil tank can also receive 2.5 percent sulfur (or less) fuel oil for burning in Boiler Nos. 1 through 4, the actual sulfur content of the fuel oil burned in Boiler Nos. 1 through 5 is somewhere between 2.5 percent and 1.0 percent.

The air pollution control equipment for Boiler No. 5 consists of a Joy Turbulaire type spray impingement scrubber for particulate matter control, and good combustion practices for control of NO_x, CO, and VOC emissions. A 90-foot-tall stack provides for dispersion of air emissions from the boiler. Permitted emission rates for PM are 0.15 lb/MMBtu when combusting bagasse fuel and 0.10 lb/MMBtu when combusting fuel oil. For SO_2, maximum allowable emissions are 0.30 lb/MMBtu when combusting bagasse and 1.1 lb/MMBtu for oil burning. NO_x emissions are limited to 0.16 lb/MMBtu for bagasse and 0.40 lb/MMBtu for fuel oil. VOC is limited to 0.25 lb/MMBtu for bagasse and 0.002 lb/MMBtu for fuel oil. CO emissions are limited to 6.5 lb/MMBtu for bagasse and 0.033 lb/MMBtu for fuel oil. The visible emissions are limited to 30 percent opacity (6-minute average), except 40-percent opacity is allowed for one 2-minute period per hour.

The proposed modification to Boiler No. 5 affects two aspects of the boiler operation. Based on historic operation of the boiler, ASA is proposing to maintain the maximum permitted steam production rates of 130,000 lb/hr as a 1-hr maximum and 115,000 lb/hr as a maximum 24-hr average. The boiler will operate at a nominal 250 psig and 550°F.

As described previously, Boiler No. 5 is currently limited to 3,000 hours operation per season. This is equivalent to 0.6778×10^{12} Btu/yr based on the currently permitted maximum 24-hr steam rate of 115,000 lb/hr, equivalent to a heat input rate of 225.9 MMBtu/hr. The proposed modification to Boiler No. 5 consists of eliminating the 3,000 hr/yr operating hours limitation and replacing it with a maximum annual heat input limitation of 0.8673×10^{12} Btu/yr. This annual heat input limitation is equivalent to 3,840 hr/yr operation at the maximum 24-hr steam rate.

A process flow diagram of Boiler No. 5 is presented in Attachment ASA-EU1-L1 of the permit application form.

2.3 PROPOSED BOILER NO. 5 EMISSIONS

2.3.1 MAXIMUM SHORT-TERM EMISSIONS

The estimated maximum hourly emissions for Boilers No. 5 operating both at the maximum 1-hr steam production rate of 130,000 lb/hr and at the 24-hr maximum steam rate of 115,000 lb/hr are shown in Table 2-1. The basis for the maximum emissions are shown in the footnotes to the table and are explained below.

The maximum heat input to Boiler No. 5 is based on the proposed maximum steam rates, 1,080 Btu/lb of steam and 55-percent thermal efficiency for bagasse and 80-percent efficiency for fuel oil. The boiler operates at a nominal steam condition of 250 psig and 550°F. The steam enthalpies and resulting heat input rates of 255.3 MMBtu/hr (1-hr maximum) and 225.9 MMBtu/hr (24-hr maximum) are shown in Table 2-1. No. 6 fuel oil can be burned at up to 470 gal/hr (equivalent to 70.5 MMBtu/hr assuming 150,000 Btu/gal). This is the current maximum firing rate for fuel oil based on design of the fuel oil burners, and will not change due to the proposed project.

Maximum PM, NO_x, and CO emissions due to carbonaceous fuel (bagasse) firing are based on the current permit limitations on a lb/MMBtu heat input basis. Historic testing data for Boiler No. 5 show that these emission limitations are appropriate for the boiler.

Maximum SO_2 emissions for the boiler are also decreasing based on the use of 0.7-percent maximum sulfur fuel oil. For bagasse firing, the current SO_2 emission limit is being reduced to 0.1 lb/MMBtu, based on test data for Boiler No. 5 (refer to Appendix B).

PM_{10} emissions are based on an estimated 93 percent of total PM emissions. This factor is based on one test conducted many years ago on a bagasse boiler.

Three years of VOC test data are available for Boiler No. 5. The test data indicate that actual VOC emissions can range up to the current limit of 0.25 lb/MMBtu. As a result, a higher VOC limit of 0.5 lb/MMBtu is being requested.

Emissions of sulfuric acid mist (SAM), lead (Pb), and beryllium (Be) due to carbonaceous fuel firing are based on emission factors (refer to Appendix C for emission factor documentation). Mercury (Hg) emissions are based on extensive stack testing performed on similar wet scrubber controlled bagasse boilers during 1992 and 1993. The maximum emission rate for any individual test run (3.8E-05 lb/MMBtu) was used as a conservative emission factor.

Maximum PM emissions due to No. 6 fuel oil firing are based on the current Boiler No. 5 permit limitation and Florida emission limit (Rule 62-296.406). Emission factors for all other pollutants for fuel oil firing are based on AP-42 factors for No. 6 fuel oil. In the case of SO_2, no inherent removal was assumed, even though the alkaline ash generated from the carbonaceous fuel burning and the wet scrubbing system likely removes some SO_2 when firing fuel oil.

As shown in Table 2-1, maximum emissions of PM, PM_{10}, CO, VOC, Pb, and Hg occur when burning 100-percent carbonaceous fuel. Maximum emissions of all other pollutants occur when burning the maximum amount of No. 6 fuel oil, with the remainder of heat input due to carbonaceous fuel.

2.3.2 MAXIMUM ANNUAL EMISSIONS

Maximum annual emissions proposed for Boiler No. 5 are presented in Table 2-2. Emission factors are the same as used for the short-term emission rates (see Table 2-1). The maximum

annual heat input to the boiler is 867,302 MMBtu/yr, equivalent to 441,600,000 lb/yr steam. For pollutants where carbonaceous fuel produces the maximum emission factor (in lb/MMBtu), this total heat input is applied to the emission factor. For pollutants where No. 6 fuel oil produces the highest factor (i.e., for SO_2, NO_x, and Be), the maximum annual heat input due to fuel oil burning (75,000 MMBtu/yr based on 500,000 gal/yr) is used, with the remainder of the annual heat input due to carbonaceous fuel.

2.4 SITE LAYOUT AND STRUCTURES

A plot plan of the ASA facility, showing stack locations and property boundaries, is presented in Attachment ASA-FE-2. The dimensions of the major buildings and structures are presented in Section 6.0.

2.5 STACK PARAMETERS

The existing stack serving Boiler No. 5 is 90 feet in height. This stack will continue to be used in the future. Stack parameters for Boiler No. 5, both current and future, are presented in Table 2-3.

Table 2-1. Future Short Term Emissions of Regulated Pollutants for ASA Boiler No. 5

Regulated Pollutant	Emission Factor (lb/MMBtu)	Ref	Activity Factor 1-Hour Max. (MMBtu/hr)(a)	Activity Factor 24-Hour Avg. (MMBtu/hr)(a)	Maximum Hourly Emissions (lb/hr)	Maximum 24-Hour Emissions (lb/hr)
			Carbonaceuos Fuel			
Particulate Matter (PM)	0.15	1	255.3	225.9	38.3	33.9
Particulate Matter (PM10)	0.14	2	255.3	225.9	35.7	31.6
Sulfur dioxide	0.10	3	255.3	225.9	25.5	22.6
Nitrogen oxides	0.25	4	255.3	225.9	63.8	56.5
Carbon monoxide	6.50	1	255.3	225.9	1,659.6	1,468.1
VOC	0.50	1	255.3	225.9	127.7	113.0
Sulfuric Acid Mist	6.13E-03	5	255.3	225.9	1.6	1.4
Lead	4.45E-04	6	255.3	225.9	0.11	0.10
Mercury	3.80E-05	7	255.3	225.9	0.010	0.0086
Beryllium	--	6	255.3	225.9	--	--
			No. 6 Fuel Oil			
Particulate Matter (PM)	0.10	1	70.5	--	7.05	7.05
Particulate Matter (PM10)	0.10	8	70.5	--	7.05	7.05
Sulfur dioxide	0.73	9	70.5	--	51.5	51.5
Nitrogen oxides	0.31	10	70.5	--	21.86	21.86
Carbon monoxide	0.033	10	70.5	--	2.33	2.33
VOC	0.0019	10	70.5	--	0.13	0.13
Sulfuric Acid Mist	4.47E-02	5	70.5	--	3.15	3.15
Lead	1.01E-05	10	70.5	--	7.12E-04	7.12E-04
Mercury	7.53E-07	10	70.5	--	5.31E-05	5.31E-05
Beryllium	1.85E-07	10	70.5	--	1.30E-05	1.30E-05
			Maximum No. 6 Fuel Oil/ Remainder Bagasse			
Particulate Matter (PM)			223.2	193.8	30.0	25.5
Particulate Matter (PM10)			223.2	193.8	28.4	24.3
Sulfur dioxide			223.2	193.8	66.7	63.8
Nitrogen oxides			223.2	193.8	60.0	52.7
Carbon monoxide			223.2	193.8	994.9	803.8
VOC			223.2	193.8	76.5	61.8
Sulfuric Acid Mist			223.2	193.8	4.1	3.9
Lead			223.2	193.8	6.87E-02	5.56E-02
Mercury			223.2	193.8	5.86E-03	4.74E-03
Beryllium			223.2	193.8	1.30E-05	1.30E-05
			Maximum Any Combination			
Particulate Matter (PM)					38.3	33.9
Particulate Matter (PM10)					35.7	31.6
Sulfur dioxide					66.7	63.8
Nitrogen oxides					63.8	56.5
Carbon monoxide					1,659.6	1,468.1
VOC					127.7	113.0
Sulfuric Acid Mist					4.1	3.9
Lead					0.11	0.10
Mercury					9.70E-03	8.58E-03
Beryllium					1.30E-05	1.30E-05

Footnotes

(a) Maximum 1-hour activity factor is based on a steam production of 130,000 lb/hr at 250 psig, 550 F.
Maximum 24-hour average activity factor based on steam production rate of 115,000 lb/hr at 250 psig, 550 F.
Enthalpy of steam = 1,290 Btu/lb. Enthalpy of feedwater = 210 Btu/lb. Net enthalpy = 1,080 Btu/lb.
Boiler efficiency = 80% on fuel oil and 55% on bagasse.
Derivation of heat input for No. 6 Fuel oil/Bagasse combination firing:
Max 1-hr case:
Max oil = 70.5 MMBtu/hr x 80% eff. =56.4 MMBtu/hr into steam
Remainder needed into steam = (130,000 lb/hr steam x 1,080 Btu/lb) - 56.4 MMBtu/hr = 84.0 MMBtu/hr
Required heat input to boiler from bagasse = 84.0 MMBtu/hr / 55% eff. = 152.7 MMBtu/hr
Total heat input required = 70.5 + 152.7 = 223.2 MMBtu/hr
Max 24-hr case:
Max oil = 70.5 MMBtu/hr x 80% eff. = 56.4 MMBtu/hr into steam.
Remainder needed into steam = (115,000 lb/hr steam x 1,080 Btu/lb) - 56.4 MMBtu/hr = 67.8 MMBtu/hr
Required heat input to boiler from bagasse = 67.8 MMBtu/hr / 55% eff. = 123.3 MMBtu/hr
Total heat input required = 123.3 + 70.5 = 193.8 MMBtu/hr

References

1. Current BACT permit limit for Boiler No. 5.
2. Based on limited source testing of bagasse boiler which indicated 93% of PM was PM10.
3. Based on source test data for Boiler No. 5.
4. Proposed BACT permit limit for Boiler No. 5.
5. Based on assuming 5% of SO2 emissions are equal to SO3, based on AP-42 Section 1.3, Fuel Oil Combustion. Conversion of SO3 to H2SO4 (SO3 x 98/80).
6. Based on AP-42, Section 1.6, Wood Waste Combustion. Represents controlled emissions.
7. Based on stack testing of 5 bagasse boilers in Florida (refer to appendices).
8. Assumed as 100% of PM emissions.
9. Based on 0.7 % S fuel oil; 150,000 Btu/gal; 7.94 lb/gal; assumes 100% conversion of sulfur to SO2.
10. Based on AP-42, Section 1.3, Fuel Oil Combustion, residual oil.
NOx - 40 lb/1000 gal; CO - 5 lb/1000 gal; VOC - 0.28 lb/1000 gal;
Lead - 1.51E-03 lb/1000 gal; Mercury - 1.13E-04 lb/1000 gal;
Beryllium - 2.78E-05 lb/1000 gal

Example Calculations

Single Fuel Combustion:
Hourly Emission Rate = Emission Factor X Activity Factor (1-hour maximum)

Footnotes

(a) Maximum 1-hour activity factor is based on a steam production of 130,000 lb/hr at 250 psig, 550 F.
Maximum 24-hour average activity factor based on steam production rate of 115,000 lb/hr at 250 psig, 550 F.
Enthalpy of steam = 1,290 Btu/lb. Enthalpy of feedwater = 210 Btu/lb. Net enthalpy = 1,080 Btu/lb.

Table 2-2. Maximum Annual Emissions Proposed for Atlantic Sugar Boiler No. 5

Pollutant	Bagasse Firing			Fuel Oil Firing			TOTAL
	Emission Factor	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	Emission Factor	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	Emissions (TPY)
Particulate Matter (PM)	0.15 lb/MMBtu	867,302	65.0	0.1 lb/MMBtu	0	0	65.0
PM10	0.14 lb/MMBtu	867,302	60.7	0.1 lb/MMBtu	0	0	60.7
Sulfur Dioxide	0.10 lb/MMBtu	792,302	39.6	0.73 lb/MMBtu	75,000	27.4	67.0
Nitrogen Oxides	0.25 lb/MMBtu	792,302	99.0	0.31 lb/MMBtu	75,000	11.6	110.7
Carbon Monoxide	6.50 lb/MMBtu	867,302	2,818.7	0.033 lb/MMBtu	0	0	2,818.7
Volatile Organic Compounds	0.50 lb/MMBtu	867,302	216.8	0.0019 lb/MMBtu	0	0	216.8
Sulfuric Acid Mist	6.13E-03 lb/MMBtu	792,302	2.4	0.045 lb/MMBtu	75,000	1.7	4.1
Lead	4.45E-04 lb/MMBtu	867,302	0.19	1.01E-05 lb/MMBtu	0	0	0.19
Mercury	3.80E-05 lb/MMBtu	867,302	0.016	7.53E-07 lb/MMBtu	0	0	0.016
Beryllium	--	792,302	--	1.85E-07 lb/MMBtu	75,000	6.94E-06	6.94E-06

(a) Total heat input based on steam production of 441.6 x 10 ^ 6 lb/yr and 1,964 Btu/lb steam.
Fuel oil considered where worst case emission factor is due to oil burning at 500,000 gal/yr.

Table 2-3. Summary of Stack Parameters for Existing and Modified Boiler No. 5.

	Steam Production Rate	Stack Height	Stack Diameter	Gas Flow Rate	Gas Velocity	Gas Temperature
	(lb/hr)	(ft)	(ft)	(acfm) a	(ft/s)	(deg F)
Boiler 5	115,000	90	5.5	90,000	63.14	150

Note: acfm = actual cubic feet per minute
deg F = degree Fahrenheit
ft/s = feet per second
ft = feet

3.0 AIR QUALITY REVIEW REQUIREMENTS

Federal and state air regulatory requirements for a new source of air pollution are discussed in Section 3.1 to 3.4. The applicability of these regulations to the modified Boiler No. 5 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 Ambient Air Quality Standards (AAQS) are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

Florida has adopted state AAQS in Rule 62-204.240. These standards are the same as the national AAQS, except in the case of SO_2. For SO_2, Florida has adopted the former 24-hr secondary standard of 260 $\mu g/m^3$, and former annual average secondary standard of 60 $\mu g/m^3$.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under Federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a pre-construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, have been approved by EPA; therefore, PSD approval authority has been granted to the Florida Department of Environmental Protection (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 CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. Once a new source is determined to be a "major facility" for a particular pollutant,

any pollutant emitted in amounts greater than the PSD significant emission rates is subject to PSD review. For an existing source for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emission rates. The PSD significant emission rates are shown in Table 3-2.

The EPA class designation and allowable PSD increments are presented in Table 3-1. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications are designated based on criteria established in the Clean Air Act Amendments. Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_2 increments.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality. The State of Florida has adopted the federal PSD regulations by reference (Rule 62-212.400, F.A.C.). Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

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

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

3.2.2 CONTROL TECHNOLOGY REVIEW

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

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

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

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978) and in the PSD *Workshop Manual* (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the

same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with new source performance standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis required the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgement, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

3.2.3 SOURCE IMPACT ANALYSIS

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

To address compliance with AAQS and PSD Class II increments, a source impact analysis must be performed for the criteria pollutants. However, this analysis is not required for a specific pollutant if the net increase in impacts as a result of the new source or modification is below

significant impact levels, as presented in Table 3-1. The significant impact levels are threshold levels that are used to determine the level of air impact analyses needed for the project. If the new or modified source's impacts are predicted to be less than significant, then the source's impacts are assumed not to have a significant adverse affect on air quality and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance AAQS and PSD increments.

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

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

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

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

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

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

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

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

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

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

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

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

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

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

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

3.2.5 SOURCE INFORMATION/GOOD ENGINEERING PRACTICE STACK HEIGHT

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

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

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

   $Hg = H + 1.5L$

   where: Hg = GEP stack height,

   H = Height of the structure or nearby structure, and

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

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

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

3.2.6 ADDITIONAL IMPACT ANALYSIS

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

3.3 NONATTAINMENT RULES

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

3.4 EMISSION STANDARDS

3.4.1 NEW SOURCE PERFORMANCE STANDARDS

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

Boiler No. 5 at ASA is an existing source. No physical changes will be made to the boiler as a result of this project. NSPS do not apply to the boiler at the present time, and NSPS will not be triggered by the proposed modification to Boiler No. 5.

3.4.2 FLORIDA RULES

FDEP regulations for existing carbonaceous fuel burning equipment are covered in Rule 62-296.410. These rules require that carbonaceous fuel burning equipment meet a PM emissions limit of 0.2 lb/MMBtu for carbonaceous fuel firing, and 0.1 lb/MMBtu for fossil fuel firing.

3.5 PSD APPLICABILITY

3.5.1 AREA CLASSIFICATION

The project site is located in Palm Beach County, which has been designated by EPA and FDEP as an attainment or maintenance area for all criteria pollutants. Palm Beach County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TPS), and NO_2. The nearest Class I area to the site is the Everglades National Park (ENP), located about 97 km (60 miles) southwest of the ASA mill site.

3.5.2 PSD REVIEW

3.5.2.1 Pollutant Applicability

The existing ASA 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 pollutant for which the increase in emissions due to the modification is greater than the PSD significant emission rates.

Current actual (baseline) emissions for Boiler No. 5 are shown in Table 3-3. The current annual emissions are based on the last two crop seasons (1997/1998 and 1998/1999) of actual operation (actual heat input due to bagasse and fuel oil). During the last two years, no fuel oil has been burned in Boiler No. 5. Emission factors for bagasse firing are based on the average the last five years of stack test results (in lb/MMBtu) for Boiler No. 5 for PM, SO_2, NO_x, and CO (refer to Appendix B). Emission factors for VOC (in lb/MMBtu) for Boiler No. 5 are based on averages for the last two years of testing, as testing was not conducted prior to that time. Mercury emissions from bagasse are based on industry test data. Emission factors for other pollutants for bagasse firing, and for all pollutants for fuel oil firing, are based on published emission factors or permit limits. Refer to the footnotes in Table 3-3 for further explanation.

Presented in Table 3-4 is the comparison of current actual emissions to future maximum emissions from Boiler No. 5 after the proposed modification (refer to Tale 2-2). As shown in Table 3-4, the potential increase in emissions due to the proposed modification of Boiler No. 5 exceeds the PSD significant emission rates for PM, PM_{10}, SO_2, NO_x, CO, and VOC. As a result, PSD review applies for these pollutants.

3.5.2.2 Source Impact Analysis

A source impact analysis was performed for PM_{10}, SO_2, NO_x and CO emissions resulting from the proposed modification. As shown in Table 3-5, the predicted increase in impacts due to the proposed modification are predicted to be below the significant impact levels for NO_x. As a result, a modeling analysis incorporating the impacts from other sources is not required for NO_x. For the other pollutants, the predicted increase in impacts are above the significant impact levels, and further modeling is required.

3.5.2.3 Emission Standards

The applicable State of Florida emission limit for PM for Boiler No. 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 No. 5 will comply with the specified limit.

3.5.2.4 Ambient Monitoring

Based on the increase in emissions from the proposed modification (see Table 3-4), a pre-construction ambient monitoring analysis is required for PM_{10}, SO_2, NO_x, CO and VOC and monitoring data is required to be submitted as part of the application. However, if the net increase in impacts of a pollutant is less than the applicable *de minimis* monitoring concentration, then an exemption from submittal of pre-construction ambient monitoring data may be obtained [40 CFR 52.21(i)(8)]. In addition, if EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

Pre-construction monitoring data for NO_x may be exempted for this project because, as shown in Table 3-5 and in Section 6.0, the proposed modification's impacts are predicted to be below the applicable *de minimis* monitoring concentration for NO_x. A pre-construction ambient monitoring analysis is required for PM_{10}, SO_2, CO, and VOC. This analysis is presented in Section 4.0.

3.5.2.5 GEP Stack Height Impact Analysis

The Boiler No. 5 stack is 90 ft high, and will not change due to this project because the modeling analysis (Section 6.0) demonstrates compliance with all ambient standards with Boiler No. 5 at this stack height. This stack height does not exceed the *de minimis* good engineering practice (GEP) stack height of 65 meters (213 feet).

3.5.3 NONATTAINMENT REVIEW

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

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

Pollutant	Averaging Time	AAQS			PSD Increments		Significant Impact Levels[b]
		National Primary Standard	National Secondary Standard	State of Florida	Class I	Class II	
Particulate Matter[c] (PM10)	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum	150[b]	150[b]	150[b]	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum	365[b]	NA	260[b]	5	91	5
	3-Hour Maximum	NA	1,300[b]	1,300[b]	25	512	25
Carbon Monoxide	8-Hour Maximum	10,000[b]	10,000[b]	10,000[b]	NA	NA	500
	1-Hour Maximum	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[c]	1-Hour Maximum	235[c]	235[c]	235[c]	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
NA = Not applicable, i.e., no standard exists.

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

[b] Short-term maximum concentrations are not to be exceeded more than once per year.

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

[d] Maximum concentrations.

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

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

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM_{10})	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour
MWC Organics	NSPS	$3.5x10^{-6}$	NM
MWC Metals	NSPS	15	NM
MWC Acid Gases	NSPS	40	NM
MSW Landfill Gases	NSPS	50	NM

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

NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
$\mu g/m^3$ = micrograms per cubic meter.
MWC = Municipal waste combustor.
MSW = Municipal solid waste.

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

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

Table 3-3. Current Actual Emissions for Atlantic Sugar Boiler No. 5

	Bagasse Firing				
Pollutant	Emission Factor		Ref.	Heat Input (a) (MMBtu/yr)	Emissions (TPY)
Particulate Matter (PM)	0.12	lb/MMBtu	1	484,126	29.0
PM10	0.11	lb/MMBtu	2	484,126	26.6
Sulfur Dioxide	0.002	lb/MMBtu	1	484,126	0.48
Nitrogen Oxides	0.144	lb/MMBtu	1	484,126	34.9
Carbon Monoxide	3.21	lb/MMBtu	1	484,126	777.0
Volatile Organic Compounds	0.15	lb/MMBtu	1	484,126	36.3
Sulfuric Acid Mist	1.23E-04	lb/MMBtu	3	484,126	0.03
Lead	4.45E-04	lb/MMBtu	4	484,126	0.11
Mercury	3.80E-05	lb/MMBtu	5	484,126	9.20E-03
Beryllium	--		4	484,126	0.0

(a) Based on actual steam production during 97-98 and 98-99 crop seasons, and design steam enthalpies for Boiler No. 5. (246.5x10^6 lbs steam/yr @ 1964 Btu/lb).

Footnotes:

(1) Based on average of stack tests from last 5 years.
(2) Based on 93% of PM emissions for bagasse burning.
(3) Based on assuming 5% of SO2 emissions are equal to SO3, based on AP-42 Section 1.3, Fuel Oil Combustion. Conversion of SO3 to H2SO4 (SO3 x 98/80).
(4) Based on AP-42, Section 1.6, Wood Waste Combustion. Represents controlled emissions.
(5) Based on stack testing of 5 bagasse boilers in Florida (refer to appendices).

Table 3-4. Net Emissions Increase for Belle Glade Atlantic Sugar Boiler No. 5

Pollutant	PSD Baseline Emissions (TPY)	Future Maximum Emissions (TPY)	Net Increase in Emissions (TPY)	PSD Significant Rate (TPY)	PSD Review Applies?
Particulate Matter (PM)	29.0	65.0	36.0	25	Yes
PM10	26.6	60.7	34.1	15	Yes
Sulfur Dioxide	0.5	67.0	66.5	40	Yes
Nitrogen Oxides	34.9	110.7	75.8	40	Yes
Carbon Monoxide	777.0	2,818.7	2,041.7	100	Yes
Volatile Organic Compounds	36.3	216.8	180.5	40	Yes
Sulfuric Acid Mist	0.03	4.1	4.1	7.0	No
Lead	0.11	0.19	0.09	0.60	No
Mercury	9.20E-03	1.65E-02	7.28E-03	0.10	No
Beryllium	0	6.94E-06	6.94E-06	4.00E-04	No

Table 3-5. Predicted Net Increase in Impacts Due to the Proposed Project

Pollutant	Averaging Time	Concentrations ($\mu g/m^3$) Predicted Net Increase in Impacts [a]	Significant Impact Level	*De Minimis* Monitoring Concentration
Sulfur Dioxide	Annual	0.4	1	
	24-Hour	22.5	5	13, 24-hour
	3-Hour	82.7	25	
Particulate Matter (PM_{10})	Annual	0.24	1	
	24-Hour	11.1	5	10, 24-hour
Nitrogen Dioxide	Annual	0.48	1	14, annual
Carbon Monoxide	8-Hour	1,132	500	575, 8-hour
	1-Hour	2,896	2000	
Ozone [b]	Annual	180.5	NA	100 TPY VOC

Note: TPY = Tons per year.
NA = Not applicable.

[a] See Section 6.0 for air dispersion modeling results.

[b] Preconstruction monitoring analysis required for ozone, if increase in VOC emissions is greater than 100 TPY.

4.0 AMBIENT MONITORING ANALYSIS

4.1 INTRODUCTION

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

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

As described in Section 3.5.2, NO_x can be exempted from the preconstruction ambient monitoring requirements. However, a preconstruction air monitoring analysis is required for PM_{10}, SO_2, CO, and ozone. This analysis is presented in the following section. In addition, existing ambient air quality data for the Everglades National Park Class I area, for all pollutants requiring PSD review, is presented to support the AQRV analysis presented in Section 7.0.

4.2 VICINITY OF ATLANTIC SUGAR ASSOCIATION

The PSD ambient monitoring guidelines allow the use of existing data to satisfy preconstruction review requirements and to develop background concentrations. Background concentrations are necessary to determine total ambient air quality impacts to demonstrate compliance with AAQS. "Background concentrations" are defined as concentrations due to sources other than those specifically included in the modeling analysis. For all pollutants, background would include other point sources not included in the modeling (i.e., faraway sources or small sources), fugitive emission sources, and natural background sources.

4.2.1 PM_{10} AMBIENT BACKGROUND CONCENTRATIONS

Presented in Table 4-1 is a summary of existing ambient PM_{10} data for monitors located near the ASA facility. Data are presented for the last 2 years of record, 1997 to 1998. As shown, five PM_{10} monitors were operational in the vicinity of Belle Glade during this period. These stations, located in Belle Glade, operated in 1997 but were shutdown in 1998. Several stations were operated in Belle Glade during 1997. Only one station operated in Belle Glade during 1998. It is noted that the monitors in Belle Glade are influenced by a sugar mill located in Belle Glade, as well as mobile traffic and other urban sources of air pollutants.

The monitors show that ambient PM_{10} concentrations were well below the ambient air quality standards of 150 $\mu g/m^3$, maximum 24-hour average, and 50 $\mu g/m^3$, annual average at all sites.

For purposes of an ambient annual PM_{10} background concentration for use in the modeling analysis, the annual average PM_{10} concentration of 20 $\mu g/m^3$ recorded at both Belle Glade SR 717 municipal golf and at 38754 SR 80 monitor locations during 1997 was selected. For the 24 hour background PM_{10} concentration, 36 $\mu g/m^3$ was used in the modeling analysis. Since all other major point sources of PM within about 60 km are included explicitly in the modeling analysis, and the background concentration is to represent non-modeled sources, the lowest recorded annual and second high 24-hour concentration at any of the monitoring sites was selected. These monitors would be influenced significantly by point sources in Belle Glade, as well as mobile and area sources and would represent a conservative estimate of actual background concentrations.

4.2.2 SO_2 AMBIENT BACKGROUND CONCENTRATIONS

Presented in Table 4-2 is a summary of existing continuous ambient SO_2 data for monitors located in the vicinity of ASA. Data are presented for the last 2 years of record, 1997 to 1998. As shown, only one SO_2 monitor was operational in the vicinity of Belle Glade during this period. This station, located in South Bay, operated in 1997 but was shutdown in 1998. One station, also operated in Riviera Beach during 1997 and 1998, is located 45 km from ASA.

The monitor at South Bay shows that ambient SO_2 concentrations were well below the ambient air quality standards of : 1,300 $\mu g/m^3$, maximum 3-hour average; 260 $\mu g/m^3$, maximum 24-hour average; and 60 $\mu g/m^3$, annual average. The monitor in Riviera Beach is not considered to be representative of the ASA mill site due to the distance this monitor is from ASA, and its urban location near a major power plant. The South Bay monitor is considered representative of the ASA mill area, since it is located in a similar rural setting.

For purposes of an ambient SO_2 background concentration for use in the modeling analysis, the annual average SO_2 concentration of 5 $\mu g/m^3$ recorded at the South Bay monitor during 1997 was selected. Similarly, the concentrations used for the 3- and 24-hour background SO_2 concentrations in the air quality impact analysis were 47 and 13 $\mu g/m^3$, respectively, which are the second highest concentrations measured at the site.

4.2.3 CO AMBIENT BACKGROUND CONCENTRATIONS

Presented in Table 4-3 is a summary of existing continuous ambient CO data for monitors located in the vicinity of ASA. Data are presented for the last 2 years of record, 1997 to 1998. As shown, no CO monitors were operational in the vicinity of ASA during this period. The nearest CO monitoring stations were located in West Palm Beach.

The CO monitors show that ambient CO concentrations were well below the ambient air quality standards of: 35 ppm (40,000 $\mu g/m^3$), maximum 1-hour average; and 9 ppm (10,000 $\mu g/m^3$) maximum 8-hour average. The monitors in West Palm Beach are considered to provide a very conservative estimate of background CO concentrations for the ASA mill, due to the significant mobile traffic impacting the West Palm Beach monitors.

For purposes of an ambient CO background concentration for use in the modeling analysis, the second highest 1-hour CO concentration of 5 ppm (5,555 $\mu g/m^3$) and the second highest 8-hour concentration of 3 ppm (3,333 $\mu g/m^3$), recorded at the South Military Trail monitor in West Palm Beach during 1997 were selected. These concentrations, although lower than at the other two West Palm Beach stations, are still very conservative since this monitor is impacted by significant mobile sources, unlike the ASA mill area.

4.2.4 AMBIENT OZONE CONCENTRATIONS

Presented in Table 4-4 is a summary of existing continuous ambient ozone data for monitors located in the vicinity of ASA. Data are presented for the last 2 years of record, 1997 to 1998. As shown, no ozone monitors were operational in the vicinity of ASA during this period. The nearest ozone monitoring station was located in Royal Palm Beach.

The ozone monitors show that ambient ozone concentrations were below the ambient air quality standards of: 0.12 ppm (235 $\mu g/m^3$), maximum 1-hour average allowed to be exceeded on average one day per year; and 0.08 ppm (157 $\mu g/m^3$), average annual fourth highest 8-hour average. The monitor in Royal Palm Beach is considered to be representative of the ASA mill area since it is relatively close to ASA.

4.3 EVERGLADES NATIONAL PARK CLASS I AREA

Presented in Table 4-5 is a summary of existing ambient PM/PM_{10}, SO_2, and NO_2 monitoring data for monitors located in the vicinity of the Everglades National Park Class I area. One PM_{10} monitor and one SO_2 monitor was located directly in the Everglades National Park in 1997 and 1998. The nearest NO_2 data is from a site located in downtown Miami.

The monitoring data show that ambient PM_{10} concentrations were well below the ambient air quality standards of 150 $\mu g/m^3$, maximum 24-hour average, and 50 $\mu g/m^3$, annual average, and ambient SO_2 concentrations were extremely low and are representative of natural background concentrations.

Table 4-1. Summary of PM_{10} Ambient Monitoring Data Collected Near Belle Glade

Year	County	Station ID	Monitor Location	Number of Observations	Concentration ($\mu g/m^3$) Maximum 24-Hour	2nd High 24-Hour	Annual Average
1997	Palm Beach	0240-008-G01	Belle Glade - 38754 SR 80	61	45	39	20
	Palm Beach	0240-004-J02	Belle Glade - SR 717, Municipal Golf	57	43	39	20
	Palm Beach	0240-006-J02	Belle Glade - 273 SE Avenue E	60	47	44	22
	Palm Beach	3420-010-J02	Belle Glade - P.O. Box 484	55	81	75	26
	Palm Beach	3420-011-J02	Belle Glade - SR 80	61	36	36	21
1998	Palm Beach	12-099-0008	Belle Glade - 38754 SR 80	50	82	59	27

Note: $\mu g/m^3$ = micrograms per cubic meter.

Table 4-2. Summary of Sulfur Dioxide Ambient Monitoring Data Collected Near Belle Glade

Year	County	Station ID	Monitor Location	Number of Observations	Concentration ($\mu g/m^3$) Maximum 3-Hour	2nd High 3-Hour	Maximum 24-Hour	2nd High 24-Hour	Annual Average
1997	Palm Beach	4150-001-J02	South Bay - 300 North US 27	8,486	55	47	19	13	5
	Palm Beach	3840-004-G02	Riviera Beach - 1050 15th Street	8,274	165	154	50	37	4
1998	Palm Beach	12-099-3004	Riviera Beach - 1050 15th Street	8,299	177 (0.068 ppm)	31 (0.012 ppm)	24 (0.009 ppm)	10 (0.004 ppm)	3 (0.001 ppm)

Note: $\mu g/m^3$ = micrograms per cubic meter.

Table 4-3. Summary of Carbon Monoxide Ambient Monitoring Data Collected Near Belle Glade

Year	County	Station ID	Monitor Location	Number of Observations	Concentration (ppm) Maximum 1-Hour	2nd High 1-Hour	Maximum 8-Hour	2nd High 8-Hour
1997	Palm Beach	4760-004-G01	West Palm Beach - 3730 Belvedere Road	8,232	11	10	7	3
	Palm Beach	4760-005-G01	West Palm Beach - 4356 Okeechobee Blvd.	3,547	7	7	5	3
	Palm Beach	4760-006-G01	West Palm Beach - 50 South Military Trail	843	6	5	4	3
1998	Palm Beach	12-099-1004	West Palm Beach - 3700 Belvedere Road	8,280	6.0	5.6	2.7	2.5
	Palm Beach	12-099-1006	West Pam Beach - 50 South Military Trail	8,476	5.4	5.3	3.0	3.0

Note: ppm = parts per million.

Table 4-4. Summary of Continuous Ozone Ambient Monitoring Data Collected Near Belle Glade

Year	County	Station ID	Monitor Location	Number of Observations	Concentration (ppm) Maximum 1-Hour	2nd High 1-Hour	3rd High 1-Hour
1997	Palm Beach	3420-007-G01	Royal Palm Beach Royal Palm Beach Storage	8,005	0.087	0.078	0.074
1998	Palm Beach	12-099-0007	West Palm Beach - 10999 Okeechobee Blvd.	8,424	0.094	0.092	0.087

Note: ppm = parts per million.

Table 4-5. Summary of Sulfur Dioxide, PM_{10}, and NO_2 Monitoring Data, Everglades National Park

Year	County	Station ID	Monitor Location	Number of Observations	Concentration ($\mu g/m^3$) Maximum 24-Hour	2nd High 24-Hour	Annual Average
SO_2 Monitoring Data							
1997	Dade	National Park Service	Within Everglades National Park	94	0.52	0.18	0.044
1998	Dade	National Park Service	Within Everglades National Park	66	0.72	0.68	0.13
PM_{10} Monitoring Data							
1990	Dade	National Park Service	Within Everglades National Park	89	79	44	20
1991	Dade	National Park Service	Within Everglades National Park	53	38	37	18
NO_2 Monitoring Data							
1997	Dade	2700-002-G01	Miami - 864 NW 3rd Street	8,477	NA	NA	31
	Dade	0860-027-G01	Miami - Rosenstiel School	7,854	NA	NA	13
1998	Dade	12-025-4002	Miami - 864 NW 3rd Street	8,427	NA	NA	28 (0.015 ppm)
	Dade	12-025-0027	Miami - Rosenstiel School	7,019	NA	NA	11 (0.006 ppm)

Note: $\mu g/m^3$ = micrograms per cubic meter.
Source: Improve, NPS.

5.0 CONTROL TECHNOLOGY REVIEW

5.1 APPLICABILITY

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may potentially be emitted above significant emission rates. For the proposed modification to Boiler No. 5, the control technology review requirements of the PSD regulations are applicable to emissions of PM/PM_{10}, SO_2, NO_x, CO, and VOC (see Section 3.5). Maximum emissions are based on Boiler No. 5 operating an equivalent of 160 days per year at 115,000 lb/hr steam. Boiler No. 5 is an existing boiler with an existing wet scrubber control system. Emissions will be controlled by the existing wet scrubber and through good combustion practices. The existing technology results in the best available control technology considering economic, environmental, and energy impacts.

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

5.2 BEST AVAILABLE CONTROL TECHNOLOGY FOR PARTICULATE MATTER

Historically, only two types of control devices have been used for PM/PM_{10} control for bagasse-fired boilers. These consist of wet scrubber technology and electrostatic precipitator (ESP) technology. Wet scrubber technology is used on all existing bagasse-fired boilers in Florida, Louisiana and Texas, except for one boiler located in Florida. The lone ESP application is installed on Boiler No. 7 located at the U.S. Sugar Clewiston mill.

The wet scrubbing systems used in Florida, generally wet impingment type scrubbers, have permitted levels of PM/PM_{10} emissions ranging from 0.15 to 0.30 lb/MMBtu. The single ESP

application has a permitted PM/PM_{10} emission level of 0.03 lb/MMBtu. However, the 0.03 lb/MMBtu emission level was only achievable after installation of a wet cyclone ahead of the ESP, at additional capital cost.

A total of six bagasse boilers have previously been issued BACT determinations for PM. All these boilers are located in Florida. These consist of five boilers with wet scrubbers, all with PM limits of 0.15 lb/MMBtu, and the one boiler with an ESP control, with a PM limit of 0.03 lb/MMBtu.

Since wet scrubber and ESPs are the only proven PM/PM_{10} control technologies on bagasse-fired boilers, and levels of 0.03 lb/MMBtu are achievable with the ESP, no other control technologies were evaluated.

The existing spray impingement scrubber operating on Boiler No. 5 is an efficient, low energy control device. As demonstrated by the past five years of compliance data for Boiler No. 5 (Appendix B), individual test runs for PM emissions have ranged from 0.084 to 0.159 lb/MMBtu, and have averaged 0.12 lb/MMBtu. Allowable emissions, based on the previous BACT determination for Boiler No. 5, are 0.15 lb/MMBtu.

Based on the sole ESP installation on a bagasse-fired boiler (at the U.S. Sugar Clewiston mill), the ESP is considered to be technically feasible. However, this is conditioned upon an effective pre-treatment device, such as a wet cyclone. This device is needed to prevent excessive wear upon the ID fan, as well as reduce the total particulate loading to the ESP and to remove a majority of the larger size particles which may otherwise be carried through the ESP.

An economic analysis was performed to investigate the cost effectiveness of installing an ESP on the existing Boiler No. 5. The economic analysis is presented in Table 5-1. The purchased equipment cost is based on actual costs for the ESP and wet cyclone on Boiler No. 7 at U.S. Sugar's Clewiston mill. The ESP cost for Boiler No. 7 was ratioed based on the respective air flow rates for Boiler No. 5 and Boiler No. 7, as shown in the footnotes to Table 5-1. The purchased equipment cost includes all equipment and installation costs except foundations, site

preparation, and ductwork. Costs for these items were based on actual costs for the ESP on Boiler No. 7.

Energy costs for operation of the wet cyclone/ESP were based on standard cost methods from the *OAQPS Cost Control Manual.* The primary energy cost is fan power. Based on the combination of wet cyclone and ESP, as well as ductwork, a total pressure drop across the system of 10 in H_2O was estimated.

Also, based on the *OAQPS Cost Control Manual, Section 6*, which addresses ESPs, a retrofit cost multiplier of 1.4 was assumed. The cost manual recommends a retrofit multiplier of between 1.3 and 1.5, based on the need to move existing structures, more complicated ductwork, additional supports, and having to work in confined areas, all associated with retrofit installations.

The following are also noted in regards to the cost analysis:

1. A wet cyclone was included in the cost analysis because the existing impingement scrubber would need to be replaced due to excessive moisture in the flue gas, which would interfere with the operation of an ESP.
2. The estimate that an operator will be required for 8 hours per day is based on operational experience for Boiler No. 7; the only known application of an ESP on a bagasse fired boiler. This figure is due to the lack of any previous operating experience with an ESP in the sugar industry. As the OAQPS cost manual is intended as a guide in lieu of situation-specific information, U.S. Sugar's operational experience is a better indicator of the time and effort required to operate and maintain an ESP on a bagasse fired boiler.
3. The capital cost recovery factor of 7 percent presented in the OAQPS cost manual is used to illustrate example cost calculations. More appropriately, the actual cost of borrowing money should be used, which in this case was assumed to be 9 percent and is representative of current economic conditions (i.e., prime rate plus 1 percent).
4. The OAQPS manual indicates a range of useful equipment life for an ESP of 5 to 40 years. Due to the lack of industry data for a ESP on a bagasse fired boiler and the

maintenance/replacement costs already incurred for the ESP on Boiler No. 7, an estimate of 15 years was used for the equipment life of the ESP in this cost analysis.

5. The efficiency of the ESP for Boiler No. 5 was based on the vendor guarantee of 0.03 lb/MMBtu for Clewiston Boiler No. 7, although this level of emissions was not achievable on Boiler No. 7 until the wet cyclone was added preceding the ESP. The only difference is that for Boiler No. 5 the current emissions are already controlled to 0.12 lb/MMBtu, but an ESP would still only achieve a 0.03 lb/MMBtu emission level, since the existing scrubber would be replaced.

The total capital cost of the ESP control system for Boiler No. 5 is estimated at $1.9 million. Total annual costs are estimated at $507,600. Baseline PM emissions for the cost effectiveness calculation is based on the average historic emissions for Boiler No. 5 of 0.12 lb/MMBtu, and the proposed maximum annual heat input of 867,302 MMBtu/yr. Therefore, the ESP system will reduce PM emissions from the existing level of 0.12 lb/MMBtu down to 0.03 lb/MMBtu, resulting in a reduction in PM emissions of 39 TPY. The resulting cost effectiveness of the ESP system is $13,000/ton of PM removed.

This cost effectiveness is much higher than costs previously determined to be reasonable for bagasse-fired boilers, and is considered economically infeasible for the proposed modification. The cost effectiveness of an ESP was significantly less for U.S. Sugar's Clewiston Boiler No. 7 for the primary reason that Boiler No. 7 was a new boiler and, therefore, its uncontrolled emissions were the basis of the cost effectiveness calculations. Boiler No. 5 is an existing source with controlled PM emissions averaging 0.12 lb/MMBtu. This is the starting point for its cost effectiveness calculations, not uncontrolled emissions. As such, annual uncontrolled emissions for cost effectiveness calculations for Boiler No. 7 were much higher than for Boiler No. 5.

Other factors which rendered the Clewiston Boiler No. 7 cost effectiveness lower are: 1) Boiler No. 7 was permitted to operate on full load year around (Boiler No. 5 will be limited to an equivalent of 160 days/yr operation); and 2) Boiler No. 7 has a much higher heat input rate than Boiler No. 5 (812 compared to 255 MMBtu/hr). Both these factors lower the cost effectiveness of an ESP, making it economically feasible for Boiler No. 7, but not for Boiler No. 5. Boiler No. 7 is

certainly not similar to Boiler No. 5, in design or operation and, therefore, separate cost analysis are warranted.

Based on the economic analysis, BACT for PM is determined to be the existing wet spray impingement scrubber system meeting an emission limit of 0.15 lb/MMBtu. This emission limit was deemed to represent BACT previously for Boiler No. 5. The ESP was determined to represent BACT for a much larger boiler than Boiler No. 5, and for a boiler that was permitted to operate year around. Boiler No. 5 will only operate an equivalent of 160 days per year at full steam load.

By permit condition, Boiler No. 5's scrubber must be equipped with a manometer or equivalent instrument to measure the total pressure drop across the scrubber, pressure gauges to measure the water pressure at the spray nozzles, and a flow meter or equivalent device (weir) to measure the quantity of water circulating through the scrubber. The boiler shall not be operated if the pressure is less than 35 psig on 14 spray nozzles and 60 psig on 24 spray nozzles, the flow through the scrubber is less than 550 GPM, or pressure drop across the scrubber is less than the values shown below:

Steam Production (1 hour average)	Minimum Pressure Drop
Up to 110,000 lb/hr	6 inches water
110,000 - 115,000 lb/hr	7 inches water
115,000 - 125,000 lb/hr	8 inches water
125,000 - 130,000 lb/hr	10 inches water

The restrictions on scrubber parameters are minimum allowable levels that apply except during startup, shutdown, and malfunction (limited 2 hours/24 hour period) or compliance testing. These parameters may be changed by the Department (BAR) in the future if it can be shown that other values assure compliance.

Using information recorded during the last crop season, the actual range for the scrubber pressure drop has historically ranged from 6 to 11 inches H_2O. The water pressure at the spray

nozzles have ranged from 50 to 70 psig with typical operation between 55 and 65 psig. The scrubber water flow rate has ranged from 260 to 330 gpm on Line 1, and from 480 to 720 gpm on Line 2. Based on this actual operation, for which compliance with the particulate matter (PM) emission limit was demonstrated, the optimum range for pressure drop is 6 to 11 inches H_2O. As for other Joy type scrubbers in the sugar industry, the manufacturer's recommended pressure drop range is from 5 to 9 inches H_2O. ASA typically operates slightly above this range to obtain better performance and improved PM removal. On this basis, the following scrubber operating parameters are proposed to support the BACT emission limit for PM:

- Pressure drop — 6 inches in H_2O or greater
- Water pressure at spray nozzles — 35 psig on 14 spray nozzles; 60 psig on 24 spray nozzles
- Water flow rate — 550 gpm or greater

5.3 BEST AVAILABLE CONTROL TECHNOLOGY FOR NO_X

Historically, only good combustion practices (GCP) have been used to control NO_x emissions from bagasse-fired boilers. All previous BACT determinations for bagasse-fired boilers for NO_x have been based on GCP. The previous BACT determination for Boiler No. 5 resulted in GCP being determined as BACT for NO_x. There are no other technologies which are technically and economically feasible for application to bagasse-fired boilers.

NO_x emissions are inherently low from bagasse-fired boilers. This is due in part to the high moisture content of the bagasse fuel (approx. 50-55%), which acts to reduce flame and furnace temperatures. Historic NO_x emissions from Boiler No. 5 have averaged 0.14 lb/MMBtu (see Appendix B), which is very low compared to fossil fuel combustion sources. The current BACT limit for Boiler No. 5 is 0.16 lb/MMBtu for bagasse firing. However, individual test runs for NO_x on the boiler have ranged up to 0.31 lb/MMBtu. Currently, there is little margin of safety between actual emissions and allowable emissions. Also, the 0.16 lb/MMBtu limit is low compared to certain other bagasse boiler BACT limits, which have been set as high as 0.28 lb/MMBtu. In addition, minimizing CO emissions is important in bagasse boilers, and measures to minimize CO emissions lead to higher NO_x emissions. Based on these considerations, it is proposed to increase the current NO_x BACT limit for Boiler No. 5 to 0.25 lb/MMBtu.

5.4 BEST AVAILABLE CONTROL TECHNOLOGY FOR CO AND VOC

Historically, only good combustion practices (GCP) have been used to control CO and VOC emissions from bagasse-fired boilers. All previous BACT determinations for bagasse-fired boilers and these pollutants have been based on GCP. The previous BACT determination for Boiler No. 5 resulted in GCP being determined as BACT for these pollutants. There are no other technologies that are technically and economically feasible for application to bagasse-fired boilers.

CO and VOC emissions are inherently high from bagasse-fired boilers compared to fossil-fuel fired sources. This is also due to the variability and high moisture content of the bagasse fuel (approx. 50-55%), which acts to reduce flame and furnace temperatures, and produces changing combustion conditions in the furnace. Also, excess air levels are generally high in order to insure the most complete combustion of the bagasse fuel.

A CO oxidation catalyst is a control technology that has been widely applied to natural gas and distillate oil-fired sources, primarily combustion turbines. The oxidation catalyst system can reduce CO emissions by up o 90 percent. However, these systems can only be used on "clean" gas streams, i.e., gas streams that do not have high particulate, sulfur or moisture content. These contaminants foul and blind the catalyst, thereby rendering the catalyst ineffective. Also, a high temperature gas stream is required. Due to the presence of high particulate and high moisture in the exhaust gas streams of bagasse boilers, and lack of a high temperature gas stream on Boiler No. 5, the use of a CO catalyst control device is technically infeasible for Boiler No. 5.

Historic CO emissions from Boiler No. 5 have averaged 3.2 lb/MMBtu, but individual test runs have ranged from 0.8 to 7.3 lb/MMBtu (see Appendix B). This variability reflects the nature of the bagasse fuel. The current BACT limit for Boiler No. 5 is 6.5 lb/MMBtu for bagasse firing. It is proposed to retain this limit as BACT for the modified Boiler No. 5, based on the GCPs already in place for the boiler.

Historic VOC emissions from Boiler No. 5 have averaged 0.15 lb/MMBtu, but individual test runs have ranged from 0.01 to 0.25 lb/MMBtu (see Appendix B). This variability reflects the nature of the bagasse fuel. The current BACT limit for Boiler No. 5 is 0.25 lb/MMBtu for bagasse firing. The 0.25 lb/MMBtu limit for VOC is very low compared to many other bagasse boiler reasonably available control technology (RACT) limits, which have generally been set at 1.0 to 1.5 lb/MMBtu. As shown by the test data, the current limit allows little margin of safety between actual and allowable emissions. Based on these considerations, it is proposed to increase the current NO_x BACT limit for Boiler No. 5 to 0.50 lb/MMBtu. It is also proposed to retain the GCPs already in place for the boiler.

ASA is now required to manually check and record the oxygen concentration at the inlet to the wet scrubber once per week by means of a portable oxygen analyzer. Based on this procedure, oxygen readings over the last crop season ranged from 5.5 to 13 percent O_2. This procedure does not provide hourly averages, but does provide an indication of variability in oxygen concentrations.

It is proposed that data collection continue for the coming crop season, which will include stack testing for CO emissions three times during the season. After this data collection, the data will be evaluated and an appropriate range of oxygen level established for the boiler. The oxygen monitor will then be configured to trip an alarm whenever the oxygen content falls outside the established range. Corrective actions would then be implemented to bring the oxygen level within the established range, consistent with proper boiler operation and meeting steam production demands.

5.5 BEST AVAILABLE CONTROL TECHNOLOGY FOR SO_2

Bagasse fuel is inherently low in sulfur, and therefore produces low SO_2 emissions. The previous BACT for Boiler No. 5 resulted in an SO_2 limit for bagasse firing of 0.30 lb/MMBtu. Limited SO_2 testing on Boiler No. 5 has resulted in emissions ranging from 0.0004 to 0.0057 lb/MMBtu, and averaged 0.0020 lb/MMBtu (see Appendix B).

SO_2 removal is inherent to the process of combusting bagasse. The fly ash produced during bagasse firing is alkaline in nature and acts as a dry scrubbant, adsorbing SO_2 from the exhaust stream. The fly ash, along with the adsorbed SO_2, is then removed by the scrubber. The alkaline nature of the fly ash also maintains the pH of the scrubber water, further enhancing SO_2 removal. Evidence of the inherent removal of SO_2 is apparent on review of the SO_2 stack test results for Clewiston Boiler No. 7, presented in the recent PSD application for U.S. Sugar Corporation's PSD permit application for Clewiston Boiler No. 4. The only control equipment employed on Boiler No. 7 is an ESP, yet calculated SO_2 removal efficiencies average 96 percent.

As shown in the stack tests for Boiler No. 5, the removal efficiency with the wet scrubber only on Boiler No. 5 has ranged from 98.0 to 99.9 percent, based on individual test runs. As such, monitoring the pH of the scrubber water is not necessary as an indicator of the efficiency of SO_2 control.

To the best of our knowledge, specific stack tests have not been performed to quantify the potential control effectiveness of maintaining or enhancing the alkaline scrubbing media. Based on the SO_2 stack tests performed on the Boiler No. 5 at ASA, ASA is willing to reduce the allowable SO_2 emission limit for bagasse to 0.1 lb/MMBtu, which allows an adequate safety margin above the actual test results. ASA is also willing to conduct a stack test to once again verify that this emission limit is achievable.

Fuel oil burning in ASA Boiler No. 5 is currently limited to 25.1 MMBtu/hr, or about 500,000 gal/yr. Because fuel oil is costly compared to bagasse, fuel oil usage is minimized. The current permit and BACT determination for Boiler No. 5 is 1.0% sulfur fuel oil. ASA proposes as BACT to replace any fuel burned in Boiler No. 5 during a crop season with 0.7 percent sulfur (maximum) fuel oil into the common fuel oil storage tank for Boiler Nos. 1 through 5. The replacement fuel would be delivered during the same crop season.

An analysis of the cost effectiveness of reducing SO_2 emissions by buying fuel oil with a sulfur content of less than 0.7 percent is presented below. First, however, the aspect of requiring a separate fuel oil storage tank for Boiler No. 5 is addressed. Currently, Boiler Nos. 1 through 5

have a common fuel oil storage tank. As shown in Table 5-3, the cost of a new, separate fuel oil tank for Boiler No. 5 would be approximately $155,000. This high cost would provide absolutely no environmental benefit, since the same reduction in SO_2 emissions achieved by placing the lower sulfur fuel into a common tank. The only difference is that, with a common tank, the SO_2 reduction is spread out over all the boilers at the mill.

Fuel costs and calculated emission rates for two alternative SO_2 control scenarios is presented in Tables 5-2 through 5-5. Fuel costs and associated SO_2 emissions are presented in Table 5-2. The alternatives are as follows:

1. Replacing the proposed 0.7 percent sulfur No. 6 fuel oil burned with No. 2 fuel oil with a sulfur content of 0.5 percent. This option would require a new storage tank and replacement of the current oil burners in Boiler No. 5, which are not capable of firing No. 2 fuel oil (see Table 5-3).
2. Replacing the proposed 0.7 percent sulfur No. 6 fuel oil burned with No. 2 fuel oil with a sulfur content of 0.05 percent. This option would also require a new storage tank and burner replacement (see Table 5-4).

For the cost effectiveness calculations, the Boiler No. 5 permitted fuel oil usage of 500,000 gal/yr is used. The results of the analysis are shown in Table 5-5. Clearly, the cost effectiveness of the two options involving switching to No. 2 fuel oil are unreasonable (over $4,000 per ton of SO_2 removed). This is due to the relatively small reduction in SO_2 emissions (up to 25.9 TPY) measured against the capital cost of a new storage tank and replacement of the burners.

Given the costs associated with switching Boiler No. 5 to No. 2 fuel oil and adding another fuel oil tank, ASA requests that BACT be determined to be the replacement of an equivalent amount of No. 6 fuel oil, with a maximum sulfur content of 0.7 percent, of any fuel oil burned in Boiler No. 5 during a crop season.

Table 5-1. Cost Effectiveness of ESP for Boiler No. 5, Atlantic Sugar Association

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
(1) Purchased Equipment Cost		
(a) Basic Equipment/Services	Based on Vendor Quote (a)	900,000
(b) Instrumentation & Controls	Based on Vendor Quote	included
(c) Wet Cyclone	Based on wet cyclone cost for USS Blr No. 7	100,000
(d) Exhaust Fan	Based on Vendor Quote	included
(d) New Stack	Based on Vendor Quote	included
(e) Ductwork	Based on USS Boiler No. 7 ESP costs	75,000
(f) Freight	Based on Vendor Quote	included
(g) Sales Tax (Florida)	Based on Vendor Quote	included
(h) Subtotal		1,075,000
(2) Direct Installation	Based on Boiler No. 7 ESP costs (b)	300,000
Total DCC:	(1h) + (2)	1,375,000
INDIRECT CAPITAL COSTS (ICC): (c)		
(3) Indirect Installation Costs		
- Engineering, Const & Field Expense, Contractor Fee, Contingencies	Based on Vendor Quote	included
(4) Other Indirect Costs		
(a) Startup & Testing	Based on Vendor Quote	included
Total ICC:	(3) + (4)	0
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	1,375,000
RETROFIT COST FACTOR (c)	0.4 x TCI	550,000
ADJUSTED TOTAL CAPITAL INVESTMENT (TCI)		1,925,000
DIRECT OPERATING COSTS (DOC): (d)		
(1) Operating Labor		
Operator	$17/hr; 160 days/yr @ 8 hrs/day	21,760
Supervisor (c)	15% of operator cost	3,264
(2) Maintenance (c)		
Labor	Equivalent to Operating Labor	25,024
Materials	Equivalent to Maintenance Labor	25,024
(3) Utilities		
(a) Electricity- Fan power (c)	203 kw; 160 days/yr; $0.07/kw-hr	54,566
Electricity- TR sets & rappers (c)	58 kw; 160 days/yr; $0.07/kw-hr	15,590
Electricity- Hopper heaters (c)	3 kw; 160 days/yr; $0.07/kw-hr	1,613
Total DOC:	(1) + (2) + (3)	146,842
INDIRECT OPERATING COSTS (IOC): (c)		
(7) Overhead	60% of oper. labor & maintenance	45,043
(8) Property Taxes	1% of total capital investment	19,250
(9) Insurance	1% of total capital investment	19,250
(10) Administration	2% of total capital investment	38,500
Total IOC:	(7) + (8) + (9) + (10)	122,043
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.124 times TCI (15 yrs @ 9%)	238,700
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	507,585
BASELINE PM EMISSIONS (TPY) :	0.12 lb/MMBtu @ 867,302 MMBtu/yr	52
MAXIMUM PM EMISSIONS WITH ESP (TPY):	0.03 lb/MMBtu @ 867,302 MMBtu/yr	13
REDUCTION IN PM EMISSONS (TPY):		39
COST EFFECTIVENESS:	$ per ton of PM Removed	13,015

Notes:

(a) Based on actual cost of ESP for Clewiston Boiler No. 7. Adjusted based on air flow rates of Boiler No. 5 vs. Boiler No. 7:
USS Boiler No. 7: $2.0 million for 255,000 acfm @ 300 deg. F
ASA Boiler No. 5: 90,000 acfm @ 150 deg. F = 112,000 acfm @ 300 deg. F
$ 2.0 million x 112,000 / 255,000 = $0.9 million

(b) All direct installation costs are included in basic price, except for local site preparation and foundations. Site preparation and foundation costs based on actual costs for Boiler No. 7 ESP.

(c) Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

(d) Based on U.S. Sugar actual costs, unless otherwise noted.

Table 5-2. Fuel Sulfur Content, Fuel Cost and SO_2 Emission Rates

Fuel Type/ Sulfur Content	Unit Cost ($/gal)	Usage (gal/yr)	Annual Cost ($/yr)	Cost Increase ($/yr)	SO_2 Emission Rate[a] (TPY)
No. 6 Fuel Oil					
0.7% Sulfur	0.6179	500,000	308,929	--	27.8
No. 2 Fuel Oil					
0.5% Sulfur	0.6607	535,714 [b]	353,954	45,026	18.3
0.05% Sulfur	0.6845	555,556 [b]	380,291	71,362	1.9

Notes:
1. All prices based on Coastal Fuels Marketing, Inc.'s current prices (FOB)

Footnotes:
[a] Based on the following information:

Fuel Type	Sulfur Content (% by wt.)	Heat Content (Btu/gal)	Density (lb/gal)
No. 2 Fuel Oil	0.05	135,000	6.83
	0.5	140,000	6.83
No. 6 Fuel Oil	0.7	150,000	7.94

[b] Gallons needed for equivalent heat input to No. 6 fuel oil with a sulfur content of 0.7%.

Table 5-3. Cost Effectiveness of 0.5% Sulfur No. 2 Fuel Oil With New Tank and Burners for ASA Boiler No. 5

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost		
1) Tank	Based on actual costs of installation of a similar tank	80,000
2) Foundations	Based on actual costs of installation of a similar tank	50,000
3) Pumps, piping, etc.	Based on actual costs of installation of a similar tank	25,000
4) No. 2 Fuel Oil Burners (2)	Vendor quote	120,000
Total PEC:		275,000
INDIRECT CAPITAL COSTS (ICC):		Included Above
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	275,000
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator		0
Supervisor	15% of operator cost	0
(2) Maintenance		
Labor	Equivalent to Operating Labor	0
Materials	Equivalent to Maintenance Labor	0
(3) Utilities		
(4) Fuels		
No. 2 Fuel (0.5% Sulfur Content)	See Footnote "a"	45,026
Total DOC:		45,026
INDIRECT OPERATING COSTS (IOC):[b]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	2,750
Insurance	1% of total capital investment	2,750
Administration	2% of total capital investment	5,500
Total IOC:		11,000
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.109 times TCI (20 yrs @ 9%)	29,975
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	86,001
BASELINE SO_2 EMISSIONS (TPY) :	500,000 gallons No. 6 Fuel Oil with a Sulfur Content of 0.7% by weight	27.8
MAXIMUM SO_2 EMISSIONS (TPY):	535,714 gallons No. 2 Fuel Oil with a Sulfur Content of 0.5% by weight	18.3
REDUCTION IN SO_2 EMISSONS (TPY):		9.5
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	9,053

Footnotes:

[a] Increase in fuel cost associated with buying No. 2 fuel oil with a sulfur content of 0.5% ($0.6607/gal) instead of No. 6 fuel sulfur content 0.7% ($0.6179/gal) based on purchasing 500,000 gallons per year.

[b] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

Table 5-4. Cost Effectiveness of 0.05% Sulfur No. 2 Fuel Oil With New Tank and Burners for ASA Boiler No. 5

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost		
1) Tank	Based on actual costs of installation of a similar tank	80,000
2) Foundations	Based on actual costs of installation of a similar tank	50,000
3) Pumps, piping, etc.	Based on actual costs of installation of a similar tank	25,000
4) No. 2 Fuel Oil Burners (2)	Vendor quote	120,000
Total PEC:		275,000
INDIRECT CAPITAL COSTS (ICC):		Included Above
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	275,000
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator		0
Supervisor	15% of operator cost	0
(2) Maintenance		
Labor	Equivalent to Operating Labor	0
Materials	Equivalent to Maintenance Labor	0
(3) Utilities		
(4) Fuels		
No. 2 Fuel (0.05% Sulfur Content)	See Footnote "a"	71,362
Total DOC:		71,362
INDIRECT OPERATING COSTS (IOC):[b]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	2,750
Insurance	1% of total capital investment	2,750
Administration	2% of total capital investment	5,500
Total IOC:		11,000
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.109 times TCI (20 yrs @ 9%)	29,975
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	112,337
BASELINE SO_2 EMISSIONS (TPY) :	500,000 gallons No. 6 Fuel Oil with a Sulfur Content of 0.7% by weight	27.8
MAXIMUM SO_2 EMISSIONS (TPY):	555,556 gallons No. 2 Fuel Oil with a Sulfur Content of 0.05% by weight	1.9
REDUCTION IN SO_2 EMISSONS (TPY):		25.9
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	4,337

Footnotes:

[a] Increase in fuel cost associated with buying No. 2 fuel oil with a sulfur content of 0.05% ($0.6845/gal) instead of No. 6 fuel oil sulfur content 0.7% ($0.6179/gal) based on purchasing 500,000 gallons per year.

[b] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

Table 5-5. Summary of the Cost Effectiveness of SO_2 Control Options

Description of Control Option	Annualized Cost ($/yr)	Maximum SO_2 Emission Rate (TPY)	Reduction in SO_2 Emission Rate[a] (TPY)	Cost Effectiveness ($/ton removed)
No. 6 Fuel Oil (0.7% S) Stored in a New Storage Tank	16,895	27.8	0.0	> 16,895[b]
Replace No. 6 Fuel Oil (0.7% S) with No. 2 Fuel Oil (0.5% S) Stored in a New Storage Tank and Replacement of Burners to Accommodate the New Fuel	86,001	18.3	9.5	9,053
Replace No. 6 Fuel Oil (0.7% S) with No. 2 Fuel Oil (0.05% S) Stored in a New Storage Tank and Replacement of Burners to Accommodate the New Fuel	112,337	1.9	25.9	4,337

Footnote:

[a] Based on a baseline SO_2 emission rate of 27.8 TPY.

[b] Cannot be exactly calculated since SO_2 reduction is zero.

6.0 AIR QUALITY IMPACT ANALYSIS

For the proposed project, the net emissions changes are greater than the PSD significant emission rates for SO_2, NO_2, PM_{10}, and CO. As a result, an air quality impact analysis is required for these four pollutants under the new source review procedures in the FDEP PSD regulations. The following section presents the air modeling approach, including methods and assumptions, and summaries of maximum pollutant concentrations predicted for comparison to AAQS and PSD increments.

6.1 AIR MODELING ANALYSIS APPROACH

6.1.1 MODEL SELECTION

The ISCST3 dispersion model (Version 99155) was used to evaluate the pollutant impacts due to the proposed project alone and in combination with other emission sources. This model is currently available on the EPA's Internet web site, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). A listing of ISCST3 model features is presented in Table 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.

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

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The ISCST3 model can run in the rural or urban land use mode, which affects stability dispersion coefficients, wind speed profiles, and mixing heights. Land use can be characterized based on a scheme recommended by EPA (Auer, 1978). If more than 50 percent of the land use within a 3-km radius circle around a project is classified as industrial or commercial, or high-density residential, then the urban option should be selected. Otherwise, the rural option is

appropriate. Based on reviews of aerial and U.S. Geological Survey (USGS) topographical maps and a site visit, the land use within a 3-km (1.9-mile) radius of the ASA site is considered to be rural (i.e., very little heavy industrial, light-moderate industrial, commercial, or compact residential land use categories). Therefore, the rural mode was used in the air dispersion model to predict impacts from the ASA site and other emission sources considered in the modeling analysis.

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

6.1.2 SIGNIFICANT IMPACT ANALYSIS

6.1.2.1 Site Vicinity

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

6.1.2.2 PSD Class I Areas

If the project is within 150 km of a PSD Class I area, then a significant impact analysis is also performed at the PSD Class I area. Currently, the EPA has proposed SIL for PSD Class I areas. If the project's impacts are above the SIL, then a more detailed air modeling analysis is

performed with PSD increment consuming and expanding background facilities to determine increment consumption at the PSD Class I area.

Because the ASA Mill is located approximately 97 km from the Everglades National Park (ENP), a PSD Class I area, a significant impact analysis was conducted at the ENP. Current FDEP policies stipulate that the highest annual average and highest short-term (i.e., 24 hours or less) concentrations are to be compared to the applicable SIL.

6.1.3 AAQS/PSD INCREMENT ANALYSES

6.1.3.1 AAQS and PSD Class II Increment Analyses

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

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

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

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

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

6.1.3.2 PSD Class I Increment Analysis

For all pollutants that have a significant impact at the PSD Class I area, a more detailed PSD increment analysis is required at the PSD Class I area. For the PSD Class I increment analysis, the PSD increment consuming and expanding sources at the ASA site are modeled with other background PSD consuming or expanding sources within 150 miles from the PSD Class I area. The maximum annual and H2H short-term PSD increments are compared to the allowable PSD Class I increments.

6.1.4 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). Concentrations were predicted using 5 years of hourly meteorological data from 1987 through 1991. The NWS office at PBI is located approximately 35 km (20 miles) east of the site and is the closest primary weather station to the study area considered to have meteorological data representative of the project site. The PBI station meteorological data have been approved by the FDEP and used for numerous air modeling studies submitted as part of air construction permits approved for sources located in Palm Beach County.

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

The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling height. The wind speed, cloud cover, and cloud ceiling values were used in the ISCST3 meteorological preprocessor program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated from the radiosonde data at Ruskin using the Holzworth approach (Holzworth, 1972). Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by EPA (Holzworth, 1972).

The hourly surface data and mixing heights were used to develop a sequential, hourly meteorological data set (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions at the NWS stations are classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed using the EPA RAMMET meteorological preprocessor program.

6.1.5 EMISSION INVENTORY

6.1.5.1 Proposed Project

The proposed project will result in Boiler No. 5 having a net increase for SO_2, NO_x, PM_{10}, and CO emissions. A summary of the current actual and future emissions and operating data of Boiler No. 5 is presented in Table 6-2. The proposed emissions and stack parameters for Boiler No. 5 future operating condition were obtained from Tables 2-1, 2-2, and 2-3. The current annual emissions for Boiler No. 5 were obtained from Table 3-3. Current actual short term emissions are based on the emission factors presented in Table 3-3, and the current maximum permitted steam rates (heat input rate), since Boiler No. 5 has operated up to these rates. Current stack parameters were obtained from Table 2-3.

While the future Boiler No. 5 can operate year-round, currently Boiler No. 5 is restricted to 3,000 hr/yr during the approximate seven-month sugar harvesting season, beginning and ending around November 1 and May 31, respectively. For modeling purposes, the current Boiler No. 5 (modeled with negative emissions) was assumed to operate for the 5-month period of November through March. For Boiler No. 5, part-year source operation is input to the air modeling analysis by using monthly emission factors for those sources. An emission factor of 1 is used for months when a source is operating, while an emission factor of zero is used for non-operating months. For the future operation of Boiler No. 5, the boiler was modeled for 8,760 hr/yr since the future operating hours will not be restricted. However, annual steam production will be restricted based on the equivalent of the boiler operating at maximum capacity for 3,840 hours.

6.1.5.2 ASA Mill

As discussed in Section 6.2.1, the maximum predicted concentrations due to the project's net emissions increase exceeds the SIL for SO_2, PM_{10}, and CO concentrations. For these pollutants, the air quality analysis must include impacts from other ASA Mill sources and other background facility sources. A summary of the stack parameters and locations used in the air modeling analysis for the future and baseline mill configuration is presented in Table 6-3. The future Mill configuration includes Boiler Nos. 1, 2, 3, 4, and 5, while the PSD baseline configuration (1974 operating conditions) includes Boiler Nos. 1, 2, 3, and 4. The stack locations for each source are relative to the location of the stack for Boiler No. 5 and are oriented to true north.

A summary of the maximum future 1-hour and 24-hour calculated SO_2 emission rates for Boiler Nos. 1 through 5 are presented in Table 6-4. SO_2 emissions due to fuel oil burning in Boiler Nos. 1 through 4 are based on a maximum 2.5 percent sulfur content, which is the current permitted fuel sulfur content. Boiler No. 5 will burn a maximum of 0.7 percent sulfur.

For Boiler Nos. 1 to 4, these sources were modeled assuming part-year operation from November through March for both the PSD baseline and future modeling scenarios. This is consistent with the approach used to model the current operation of Boiler No. 5.

A summary of the maximum calculated PM_{10} and CO emission rates for Boiler Nos. 1 through 5 are presented in Table 6-5. The PM_{10} emission rates were based on the maximum heat input rates to each boiler and the permitted PM emission rate. The CO emission rates for Boiler Nos. 1 through 4 are based on actual boiler test data. The CO emission rate for Boiler No. 5 was based on the proposed BACT emission limit.

6.1.5.3 Other Emission Sources

The emission inventories for background facilities were developed mainly from data bases from previous air modeling studies performed by Golder Associates in South Florida, and from air permit data. Emission inventories of background sources were developed for the proposed project's screening area. The modeling area is defined as the significant impact area for the proposed source. The screening area extends 50 km (30 miles) beyond the modeling area.

Within the modeling area, cumulative impact analyses were performed for ASA and all identified background sources located in the modeling and screening areas.

FDEP has approved a technique for eliminating sources in the modeling analyses if the source's emissions do not meet an emission criterion. The technique is the *Screening Threshold* method, developed by the North Carolina Department of Natural Resources and Community Development, and approved by EPA. The method is designed to objectively eliminate from the emission inventory those sources that are unlikely to have a significant interaction with the source undergoing evaluation. In general, sources that should be considered in the modeling analyses are those with emissions greater than a screening threshold value (in TPY) that is calculated by the following criteria:

$$Q = 20 \times D$$

where Q = The screening threshold value (TPY), and

D = The distance (km) from the proposed facility to the source undergoing evaluation for short-term analysis, or
the distance (km) from the edge of the proposed facility's significant impact area to the source undergoing evaluation for long-term (annual) analysis.

For this analysis, the long-term criterion was used since fewer facilities would be eliminated that with the short-term criterion. Also, the total emissions from a facility were used rather than emissions from individual sources for comparison to the screening threshold value. These methods result in a more conservative approach to produce higher-than-expected concentrations. Those facilities with maximum allowable emissions that are below the calculated *screening threshold* were eliminated from further consideration in the AAQS modeling analysis.

Sulfur Dioxide

A summary of the facilities considered for inclusion in the AAQS and PSD Class II air modeling analyses is presented in Table 6-6. As shown in this table, the facilities' locations with respect to

the ASA Mill, their annual emissions (TPY), and the calculated screening threshold are provided. The proposed project's significant impact distance is 12.5 km for both the 24-hour and 3-hour averaging times. As a result, the modeling area was limited to 12.5 km and the screening area was limited to 62.5 km for the AAQS and PSD Class II analyses. All facilities within the proposed project's modeling area (i.e., significant impact area) were included in the air modeling analyses. Those facilities eliminated from the modeling analysis using the screening threshold technique are noted in Table 6-6. For all facilities that were not eliminated, the individual source emissions, stack, and operating parameters for the AAQS and PSD Class II modeling analyses were developed.

Because the proposed project's impacts also were predicted to exceed the proposed PSD Class I SIL, a PSD Class I increment modeling analysis is required for SO_2. The facilities that were considered in the PSD Class I increment analysis (i.e., within 150 km of the Class I area) are presented in Table 6-8. All PSD increment consuming or expanding sources within these facilities are included in the analysis.

A summary of the source emissions and stack parameters for each source that was included in the SO_2 modeling analysis is presented in Table 6-7. Each source listed in Table 6-7 includes a description of the source, the ID name of the source used in the air modeling analysis, and whether the source consumes or expands PSD increment, and the analyses in which the source is included. Facilities with PSD-affecting sources may have PSD baseline sources. PSD baseline source emissions and stack configurations no longer exist but were in effect during the SO_2 PSD baseline period of 1974 to 1975. These sources expand PSD increment and are represented in the PSD increment air modeling analyses as negative emission sources.

Particulate Matter (PM_{10})

A summary of the facilities considered for inclusion in the AAQS and PSD Class II air modeling analyses is presented in Table 6-9. As shown in this table, the facilities locations with respect to the ASA Mill, annual emissions (TPY), and the calculated screening threshold are provided in Table 6-9. The proposed project's significant impact distance is 7.5 km. As a result, the modeling area was limited to 7.5 km and the screening area was limited to 57.5 km. For the

facilities to be modeled as determined by the NC screening analysis, the emission and stack parameters for each source are included in Table 6-10. Because the proposed project's impacts were less than the proposed EPA PSD Class I SIL, a PSD Class I increment modeling analysis was not required for this pollutant.

Carbon Monoxide

A summary of the facilities considered for inclusion in the AAQS air modeling analysis for CO is presented in Table 6-11. As shown in this table, the facilities' locations with respect to the ASA Mill, annual emissions (TPY), and the calculated screening threshold are provided in Table 6-11. The proposed project's significant impact area is 10 km. As a result, the modeling area was 10 km, and the screening area was 60 km. For the facilities to be modeled as determined by the NC screening analysis, the emission and stack parameters for each source are included in Table 6-12.

It should be noted that the significant impact distance was based on the 8-hour averaging time. The 1-hour average significant impact distance is 5 km. To be conservative, the modeling and screening areas for the 1-hour averaging period were the same as those for the 8-hour averaging time.

6.1.6 BUILDING DOWNWASH EFFECTS FOR ASA MILL

Based on the building dimensions associated with buildings and structures at the plant, all stacks at the ASA Mill will comply with the good engineering practice (GEP) stack height regulations. However, these stacks are less than GEP height. Therefore, the potential for building downwash to occur was considered in the air modeling analysis for these stacks.

Generally, a stack is considered to be within the influence of a building if it is within the lesser of 5 times L, where L is the lesser dimension of the building height or projected width. The ISCST3 model uses two procedures to address the effects of building downwash. For both methods, the direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector. The H_b is the building height and L_b is the lesser of the building height or projected width. For short stacks (i.e., physical

stack height is less than $H_b + 0.5 L_b$), the Schulman and Scire (1980) method is used. The features of the Schulman and Scire method are as follows:

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

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

The building dimensions considered in the air modeling analysis for the ASA Mill are presented in Table 6-13. The location of the Mill's buildings and stacks can be found on the site plot plans included with the PSD permit application and shown in Attachment ASA-FE-2. At the ASA Mill, the five boiler stacks are in the area of influence (i.e., within 5L) of the three tallest structures: the 58-ft Boiler Building, the 40-ft Mill Building, and the 88-ft Boiling House.

6.1.7 RECEPTOR LOCATIONS

6.1.7.1 Significant Impact Analysis

The maximum concentrations in the vicinity of the Mill and the distances of the project's significant impacts were predicted in a receptor grid that contained 512 receptors. This grid had both discrete and gridded polar receptors. The number of discrete receptors was 162, which included 36 receptors located at the Mill's restricted property line and 126 additional offsite receptors located at distances of 2.5, 3.0, 3.5, 4.0, and 4.5 km from Boiler No. 5's stack location. A summary of the boundary receptors at the ASA Mill is presented in Table 6-14.

An additional 360 receptors were included in a polar grid, with 36 radials extending out from the origin. Along each radial, receptors were located at distances of 5.0, 7.5, 10.0, 12.5, 15.0, 17.5, and 20 km from the origin.

A figure depicting the ASA Mill property boundaries used in the modeling analysis is presented in Figure 6-1. These boundaries have associated physical (barriers, such as canals) and in fact are all bounded by other sugar cane or agricultural fields. The access road to the plant currently is not restricted, but ASA will post appropriate signage to the north and south of the ASA mill in order to restrict public access to this road.

Pollutant concentrations for SO_2, PM_{10}, and NO_x were also predicted at 51 receptors located along the northern and eastern boundaries of the Everglades National Park (ENP) PSD Class I area. A listing of the 51 ENP receptors is presented in Table 6-15. The receptors locations are also shown in Figure 6-2.

6.1.7.2 AAQS and PSD Class II Analyses

The same receptor distances used in the significant impact analysis were used for the AAQS and PSD Class II analysis, up to the project's significant impact distance. For SO_2, PM_{10} and CO, these distances were 12.5, 7.5 and 10 km, respectively.

The impact analysis generally uses both screening and refinement phases to determine the maximum pollutant impacts. The difference between the two modeling phases is the density of the receptor grid spacing used when predicting concentrations. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record. In this analysis, the receptor grid consisted of a polar receptor grid with a 10-degree angular spacing between receptors.

Refinements of the maximum predicted concentrations from the screening phase are typically performed in the vicinity of the receptors of the screening receptor grid at which the highest predicted concentrations occurred over the 5-year period. Modeling refinements are performed to determine maximum concentrations with a receptor grid spacing of 100 meters (m).

The domain of a refined receptor grid will generally extend to all adjacent screening receptors surrounding a particular screening grid receptor. The air dispersion model is then executed with the refined grid for the entire year of meteorology during which the maximum

concentration in the screening phase occurred. This approach is used to ensure that a valid maximum concentration is obtained.

6.1.8 BACKGROUND CONCENTRATIONS

Total air quality impacts were predicted for the AAQS analysis by adding the maximum annual and highest, second-highest short-term concentrations due to all project-related sources to estimated background concentrations. Background concentrations are concentrations due to sources not associated with the ASA Mill. These concentrations consist of two components:

- Impacts due to other modeled emission sources (i.e., non-project related), and
- Impacts due to sources not explicitly modeled.

Background concentrations due to other modeled sources were predicted with the ISCST3 model based on the data developed from the emission inventories presented in Section 6.1.5.

The non-modeled background concentrations, which were obtained from air quality monitoring data, as described in Section 4.0, and are as follows:

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)
PM_{10}	24-hour	36
	Annual	20
SO_2	3-hour	47
	24-hour	13
	Annual	5
CO	8-hour	3,333 (3 ppm)
	1-hour	5,555 (5 ppm)

6.2 AIR MODELING RESULTS

6.2.1 SIGNIFICANT IMPACT ANALYSIS

6.2.1.1 Site Vicinity

The maximum SO_2, PM_{10}, NO_2, and CO concentrations due to the proposed project only that were predicted in the screening analysis are presented in Table 6-16. Based upon the screening analyses, the proposed project was determined to have a significant impact for the 3- and 24-hour average SO_2 concentrations, the 24-hour PM_{10} concentrations, and the 8-hour and 1-hour

CO concentrations. The distances of the project's significant impact area were determined to be 12.5 for the 3- and 24-hour average SO_2 concentrations; 7.5 km for the 24-hour PM_{10} concentration; and 5 and 10 km for the 1- and 8-hour average CO concentrations, respectively. Additional detailed modeling analyses are, therefore, required for each of these pollutants. The additional analyses include a comparison of all future source impacts to the AAQS for each pollutant and a PSD Class II increment analysis for SO_2 and PM_{10}.

6.2.1.2 Everglades National Park PSD Class I Area

The maximum SO_2, PM_{10}, and NO_2 concentrations predicted for the proposed project only are compared to the proposed EPA Class I significant impact levels in Table 6-17. The maximum 3- and 24-hour average SO_2 concentrations exceed the SILs, while the annual average SO_2, maximum 24-hour and annual average PM_{10} and annual average NO_2 concentrations were predicted to be below the SILs. Based on the results, the proposed project was determined to have a significant impact at the ENP for only the 3- and 24-hour average SO_2 concentrations. An additional, detailed PSD Class I increment modeling analysis was, therefore required for SO_2.

6.2.2 AAQS ANALYSES

The maximum SO_2, PM_{10}, and CO concentrations due to all future sources which were predicted from the screening analysis, is presented in Table 6-18. Based on the results of the screening analyses, refined modeling analyses were performed for each pollutant. The refined modeling results are added to measured, non-modeled background concentrations to produce total air quality concentrations that can be compared with the AAQS. A summary of the maximum total air quality impacts predicted in the refined analysis is presented in Table 6-19.

The maximum total SO_2 concentrations were predicted to be 14.6, 96, and 313 $\mu g/m^3$, respectively, for the annual, 24-hour and 3-hour averaging times. These concentrations are below the AAQS of 60, 260, and 1,300 $\mu g/m^3$, respectively, for these averaging times.

The maximum total PM_{10} concentrations were predicted to be 24 and 103 $\mu g/m^3$, respectively for the annual and 24-hour averaging times. These concentrations are all below the AAQS of 50 and 150 $\mu g/m^3$, respectively, for these averaging times.

The maximum total CO concentrations were predicted to be 6,724 and 17,196 $\mu g/m^3$, respectively for the 8-hour and 1-hour averaging times. These concentrations are well below the AAQS of 10,000 and 40,000 $\mu g/m^3$, respectively, for these averaging times.

6.2.3 PSD CLASS II ANALYSIS

The maximum SO_2 and PM_{10} increment consumption due to all PSD-affecting sources concentrations, which were predicted in the screening analysis, are presented in Table 6-20. Further refinements were not performed because the maximum impacts were well below the allowable Class II increments.

The maximum PSD increment consumption concentrations are compared to the allowable PSD Class II increments in Table 6-20. The maximum SO_2 PSD increment consumption was predicted to be 21.1 and 68.3 for the 24-hour and 3-hour averaging times, respectively. These concentrations are all below the allowable PSD Class II increments of 91 and 512 $\mu g/m^3$, respectively, for these averaging times.

The maximum PM10 PSD increment concentrations consumption is 5.5 $\mu g/m^3$, for the 24-hour averaging time. This concentration is below the allowable PSD Class II increments of 30 $\mu g/m^3$, time.

6.2.4 PSD CLASS I ANALYSIS

The maximum predicted SO_2 PSD increment consumption at the ENP PSD Class I area due to all nearby PSD-affecting sources are compared with the allowable PSD Class I increments in Table 6-21. The maximum predicted SO_2 PSD increment consumption at the ENP is 2.4 and 17.4 $\mu g/m^3$, for the 24-hour and 3-hour averaging times, respectively. These concentrations are all below the allowable PSD Class I increments of 5 and 25 $\mu g/m^3$, respectively, for these averaging times.

Table 6-1. Major Features of the ISCST3 Model, Version 99155

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

Note: ISCST = Industrial Source Complex Short-Term Model.
Source: EPA, 1999.

Table 6-2. Stack, Operating, and Emission Data for Current Actual and Future Operations for Boiler No. 5

Parameters	Current Actual Operations [b]						Future Maximum Operations					
	1-hour		24-hour		Annual		1-hour		24-hour		Annual	
STACK DATA												
Height (ft) (m)			90	27.4					90	27.4		
Diameter (ft) (m)			5.5	1.7					5.5	1.7		
OPERATING DATA												
Heat Input Rate (MMBtu/hr)	255.3		225.9		225.9		255.3		225.9		225.9	
Flow Rate (acfm) [a]	90,000		79,615		79,615		90,000		79,615		79,615	
Velocity (ft/s) (m/s)	63.1	19.2	55.9	17.0	55.9	17.0	63.1	19.2	55.9	17.0	55.9	17.0
Temperature (°F) (K)	150	338.7	150	338.7	150	338.7	150	338.7	150	338.7	150	338.7
EMISSION DATA	lb/hr	g/s	lb/hr	g/s	lb/hr [c]	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr [d]	g/s
Particulate Matter (PM)	30.6	3.9	27.1	3.4	13.3	1.7	38.3	4.8	33.9	4.3	14.9	1.9
Particulate Matter (PM10)	28.6	3.6	25.3	3.2	12.3	1.6	35.7	4.5	31.6	4.0	13.9	1.7
Sulfur dioxide	0.5	0.1	0.5	0.1	0.2	0.0	66.7	8.4	63.8	8.0	15.3	1.9
Nitrogen oxides	36.8	4.6	32.5	4.1	15.9	2.0	63.8	8.0	56.5	7.1	25.3	3.2
Carbon monoxide	819.6	103.3	725.0	91.4	355	44.7	1,660	209.1	1,468	185.0	644	81.1

[a] Flow rate based on the flow rate of 90,000 acfm at 255.3 MMBtu/hr. Other flow rates are determined by multiplying the ratio of flow of 90,000 acfm to heat input rate of 255.3 MMBtu/hr times the heat input rate for the other averaging period.

[b] Emission data based on test data.

[c] Refer to Table 3-3 for the current actual annual emissions, assuming current permit limit of 3,000 hour/year.

[d] Future permit limit for hours/year of operations = 8760

Table 6-3. Summary of Stack Parameters for Future and PSD Baseline Sources Used in Modeling of Atlantic Sugar Belle Glade Mill

Emission Unit	Modeling ID	Stack Height		Stack Diameter		Temperature		Flow Rate	Velocity		Relative Location[a]			
											X		Y	
		(ft)	(m)	(ft)	(m)	(F^o)	(K)	(acfm)	(ft/s)	(m/s)	(ft)	(m)	(ft)	(m)
FUTURE														
Boiler 1	ATLSUG1	90	27.4	6.0	1.83	160	344.3	100,000	58.9	18.0	-15	-4.57	-30	-9.14
Boiler 2	ATLSUG2	90	27.4	6.0	1.83	170	349.8	130,000	76.6	23.4	-15	-4.57	-70	-21.3
Boiler 3	ATLSUG3	90	27.4	6.0	1.83	160	344.3	120,000	70.7	21.6	5	1.52	-115	-35.1
Boiler 4	ATLSUG4	90	27.4	6.0	1.83	150	338.7	140,000	82.5	25.2	5	1.52	-155	-47.2
Boiler 5	ATLSUG5	90	27.4	5.5	1.68	150	338.7	90,000	63.1	19.2	0	0	0	0
PSD BASELINE[b]														
Boiler 1	ATLSUG1	62	18.9	6.3	1.92	451.13	506.0	77,912	41.7	12.7	-15	-4.57	-30	-9.14
Boiler 2	ATLSUG2	62	18.9	6.3	1.92	460.13	511.0	66,869	35.8	10.9	-15	-4.57	-70	-21.3
Boiler 3	ATLSUG3	72	21.9	6.0	1.83	479.93	522.0	97,530	57.4	17.5	5	1.52	-115	-35.1
Boiler 4	ATLSUG4	60	18.3	6.0	1.83	159.53	344.0	83,597	49.2	15.0	5	1.52	-155	-47.2

[a] Relative to Boiler No. 5 stack location.

[b] Representative of January 1975 operation.

Table 6-4. Future Operation for ASA Mill - Maximum Fuel Oil Burning and SO_2 Emissions

Boiler	Total Maximum Heat Input (MMBtu/hr)	Maximum Heat Input From Fuel Oil (MMBtu/hr)	Fuel Oil		Bagasse		SO_2 Emissions			
			gal/hr [a]	MMBtu/hr	lb/hr(dry)	MMBtu/hr	Fuel Oil [c] (lb/hr)	Bagasse [b] (lb/hr)	Total (lb/hr)	Total (g/s)
					MAXIMUM 1 HOUR CASE					
1	280	37.8	252	37.8	33,639	242	105.0	24.2	129.2	16.28
2	280	37.8	252	37.8	33,639	242	105.0	24.2	129.2	16.28
3	260	37.8	252	37.8	30,861	222	105.0	22.2	127.2	16.02
4	275	37.8	252	37.8	32,944	237	105.0	23.7	128.7	16.21
5	255.3	70.5	470	70.5	35,417	255 [d]	51.5 [d]	25.5 [d]	66.7	8.41 [d]
Totals	1,350	221.7	1,478	221.7	166,500	1,199	471.3	119.9	580.9	73.2
					MAXIMUM 24-HOUR CASE					
1	280	37.8	252	37.8	33,639	242	105.0	24.2	129.2	16.28
2	280	37.8	252	37.8	33,639	242	105.0	24.2	129.2	16.28
3	260	37.8	252	37.8	30,861	222	105.0	22.2	127.2	16.02
4	275	37.8	252	37.8	32,944	237	105.0	23.7	128.7	16.21
5	225.9	70.5	470	66.7	31,389	226	51.5	22.6	63.8	8.04 [d]
Totals	1,320.9	221.7	1,478	217.9	162,472	1,170	471.3	117.0	578.0	72.8

[a] Total fuel usage for all boilers based on Title V application and for Boiler No. 5, maximum fuel oil capacity.
[b] Based on maximum of 0.1 lb/MMBtu SO_2 due to bagasse firing, based on industry test data.
[c] For modeling purposes Fuel Oil Sulfur 2.5 % for Boiler No. 1-4 and 0.7% for Boiler No. 5.
[d] Refer to Table 2-1.

Notes:

Boilers 1-4
Fuel Oil - 8.33 lb/gal
18,000 Btu/lb; 150,000 Btu/gal
2.5% sulfur
Bagasse - 7,200 Btu/lb (dry); 3,600 Btu/lb (wet)

Boiler 5
Fuel Oil - 7.94 lb/gal
18,000 Btu/lb; 150,000 Btu/gal
0.7 % sulfur
Bagasse - 7,200 Btu/lb (dry); 3,600 Btu/lb (wet)

Table 6-5. Future Operation for ASA Mill -Maximum PM_{10} and CO Emissions

Source	Maximum Heat Input (MMBtu/hr)	Emission Factor		Emissions (lb/hr)	Emissions (g/s)
MAXIMUM 24-HOUR CASE - PM10 EMISSIONS					
Boilers		PM Emission Factor	PM_{10} Emission Factor		
Boiler 1	280	0.30 lb/MMBtu [a]	93% of PM	78.1	9.84
Boiler 2	280	0.30 lb/MMBtu [a]	93% of PM	78.1	9.84
Boiler 3	260	0.30 lb/MMBtu [a]	93% of PM	72.5	9.14
Boiler 4	275	0.29 lb/MMBtu [a]	93% of PM	74.2	9.35
Boiler 5	226	0.15 lb/MMBtu	93% of PM	31.6	3.98
MAXIMUM 1-HOUR CASE - CO EMISSIONS					
Boilers					
Boiler 1	280	8.5 lb/MMBtu		2,380	299.9
Boiler 2	280	16.6 lb/MMBtu		4,648	585.6
Boiler 3	260	5.5 lb/MMBtu		1,430	180.2
Boiler 4	275	5.2 lb/MMBtu		1,430	180.2
Boiler 5	255	6.5 lb/MMBtu		1,659	209.1

[a] Based on permitted emissions limit.

Table 6-6. Summary of SO_2 Facilities Considered for Inclusion in the AAQS and PSD Class II Air Modeling Analyses.

AIRS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to ASA [a] X (km)	Relative to ASA [a] Y (km)	Relative to ASA [a] Distance (km)	Relative to ASA [a] Direction (deg)	Maximum SO_2 Emissions (TPY)	Q, (TPY) Emission Threshold [b] (Dist -20) x 20	Include in Modeling Analysis ?
990026	Sugar Cane Growers	Palm Beach	534.9	2953.3	-18.0	8.1	19.7	294	2,555	144.8	YES
990016	Osceola Farms	Palm Beach	544.2	2968.0	-8.7	22.8	24.4	339	2,023	238.1	YES
990061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	-14.1	22.9	26.9	328	2,698	287.9	YES
990332	Okeelanta	Palm Beach	525.0	2937.4	-27.9	-7.8	29.0	254	939	329.4	YES
990086	Glades Correctional Institute	Palm Beach	523.4	2955.2	-29.5	10.0	31.1	289	98	373.0	NO
990021	Pratt & Whitney	Palm Beach	559.2	2978.3	6.3	33.1	33.7	11	504	423.9	YES
990234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	32.9	15.0	36.2	65	1,533	473.2	YES
990045	Lake Worth Utilities	Palm Beach	592.8	2943.7	39.9	-1.5	39.9	92	5,031	548.6	YES
990042	FPL -Riviera Beach	Palm Beach	594.2	2960.6	41.3	15.4	44.1	70	73,475	631.6	YES
510001	Everglades Sugar	Hendry	509.6	2954.2	-43.3	9.0	44.2	282	607	634.5	NO
850102	Bechtel Indiantown	Martin	545.6	2991.5	-7.3	46.3	46.9	351	2,629	687.4	YES
510003	US Sugar Clewiston	Hendry	506.1	2956.9	-46.8	11.7	48.2	284	7,806	714.8	YES
110120	North Broward Resource Recovery	Broward	583.6	2907.6	30.7	-37.6	48.5	141	896	720.8	YES
850001	FPL -Martin	Martin	543.1	2992.9	-9.8	47.7	48.7	348	93,788	723.9	YES
850007	Dickerson	Martin	569.5	2995.9	16.6	50.7	53.3	18	58	817.0	NO
850021	Stuart Contracting	Martin	575.2	3006.8	22.3	61.6	65.5	20	100	1060.2	NO
510015	Southern Gardens Citrus	Hendry	487.6	2957.6	-65.3	12.4	66.5	281	267	1079.3	NO

[a] Atlantic Sugar Association East and North Coordinates (km) 552.9 2945.2

[b] Proposed project's 24- and 3-hour emissions are significant to 12.5 km. Emission inventory is limited to facilities within 62.5 km.

Table 6-7. Summary of SO_2 Sources Included in the Air Modeling Analysis

AIRS Number	Facility	Units	Modeling ID Name	Stack Parameters: Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s): 3-Hour	24-Hour	PSD Source? (EXP/CON)	Modeled in: AAQS	Class II	Class I
0990016	Atlantic Sugar^a												
		Unit 1	ATLSUG1	27.4	1.83	346.0	17.97	10.85	10.85	CON	Yes	Yes	Yes
		Unit 2	ATLSUG2	27.4	1.83	350.0	23.36	10.85	10.85	CON	Yes	Yes	Yes
		Unit 3	ATLSUG3	27.4	1.83	350.0	21.56	10.50	10.50	CON	Yes	Yes	Yes
		Unit 4	ATLSUG4	27.4	1.83	344.0	25.16	10.76	10.76	CON	Yes	Yes	Yes
		Unit 5 PSD	ATLSUG5	27.4	1.68	339.0	19.24	8.41	8.41	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	ATLSUG1B	18.9	1.92	506.0	12.70	-17.24	-17.24	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	ATLSUG2B	18.9	1.92	511.0	10.90	-22.50	-22.50	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	ATLSUG3B	21.9	1.83	522.0	17.50	-16.88	-16.88	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	ATLSUG4B	18.3	1.83	344.0	15.00	-10.76	-10.76	EXP	No	Yes	Yes
0850102	Bechtel Indiantown PSD		BECHTIND	150.9	4.88	333.2	30.50	75.64	75.64	CON	Yes	Yes	Yes
0850001	FPL Martin												
		Units 1&2	MART12	152.1	7.99	420.9	21.03	1743.79	1743.79		Yes	No	No
		Aux Blr PSD	MARTAUX	18.3	1.10	535.4	15.24	12.90	12.90	CON	Yes	Yes	Yes
		Diesl Gens PSD	MARTGEN	7.6	0.30	785.9	39.62	0.51	0.51	CON	Yes	Yes	Yes
		Units 3&4 PSD	MART34	64.9	6.10	410.9	18.90	470.40	470.40	CON	Yes	Yes	Yes
0112120	North Broward RRF PSD		NBCRRF	58.5	3.96	381.0	18.01	35.40	35.40	CON	Yes	Yes	Yes
0990332	Okeelanta[a]												
		Boiler 4 PSD Baseline	OKBLR4B	22.9	2.29	333.0	7.36	-10.95	-10.95	EXP	No	Yes	Yes
		Boiler 5 PSD Baseline	OKBLR5B	22.9	2.29	333.0	12.07	-15.64	-15.64	EXP	No	Yes	Yes
		Boiler 6 PSD Baseline	OKBLR6B	22.9	2.29	334.0	8.74	-15.64	-15.64	EXP	No	Yes	Yes
		Boiler 10 PSD Baseline	OKBLR10B	22.9	2.29	334.0	10.35	-17.15	-17.15	EXP	No	Yes	Yes
		Boiler 11 PSD Baseline	OKBLR11B	22.9	2.29	342.0	9.89	-16.79	-16.79	EXP	No	Yes	Yes
		Boiler 12 PSD Baseline	OKBLR12B	22.9	2.29	330.0	8.16	-20.58	-20.58	EXP	No	Yes	Yes
		Boiler 14 PSD Baseline	OKBLR14B	22.9	2.29	333.0	8.28	-20.03	-20.03	EXP	No	Yes	Yes
		Boiler 15 PSD Baseline	OKBLR15B	22.9	2.29	332.0	10.23	-16.79	-16.79	EXP	No	Yes	Yes
		Okeelanta Power Blrs 1,2,3^b	OKCOGEN	68.6	3.05	438.7	17.46	27.0	27.0	CON	Yes	Yes	Yes
0990019	Osceola Farms[a]												
		Unit 2	OSBLR2	27.4	1.52	339.0	18.63	17.12	17.12	CON	Yes	Yes	Yes
		Unit 3	OSBLR3	27.4	1.92	344.0	14.34	30.74	30.74	CON	Yes	Yes	Yes
		Unit 4	OSBLR4	27.4	1.83	344.0	16.53	17.12	17.12	CON	Yes	Yes	Yes
		Unit 5	OSBLR5	27.4	1.52	344.0	17.85	18.00	18.00	CON	Yes	Yes	Yes
		Unit 6	OSBLR6	27.4	1.92	339.0	18.25	33.39	33.39	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	OSBLR1B	22.0	1.52	342.0	8.18	-5.07	-5.07	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	OSBLR2B	22.0	1.52	341.0	18.10	-16.32	-16.32	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	OSBLR3B	22.0	1.93	341.0	14.50	-7.26	-7.26	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	OSBLR4B	22.0	1.83	341.0	18.80	-13.61	-13.61	EXP	No	Yes	Yes
		Unit 5 PSD Baseline	OSBLR5B	22.0	1.52	342.0	12.12	-16.32	-16.32	EXP	No	Yes	Yes
0990234	Palm Beach Co. Resource Recovery												
		1&2 PSD	PBCRRF	76.2	2.04	505.2	24.90	85.05	85.05	CON	Yes	Yes	Yes
0990234	Pratt & Whitney												
		Heater	PRATARCH	15.2	0.91	810.9	143.73	13.99	13.99	CON	Yes	Yes	Yes
		Boiler BO-12	PRATBO12	4.6	0.76	533.2	6.92	0.51	0.51	CON	Yes	Yes	Yes

Table 6-7. Summary of SO_2 Sources Included in the Air Modeling Analysis

AIRS Number	Facility	Units	Modeling ID Name	Stack Parameters: Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s): 3-Hour	24-Hour	PSD Source? (EXP/CON)	Modeled in: AAQS	Class II	Class I
09900456	Lake Worth Utilities												
		Unit S-5	LWUS5	22.9	3.00	480.0	26.70	14.40	14.40	CON	Yes	Yes	No
		Unit CT-1	LWUCT1	14.0	4.90	720.0	24.90	28.10	28.10	CON	Yes	Yes	No
		Diesels 1-5	LWUD15	5.0	0.60	626.0	37.10	1.50	1.50	CON	Yes	Yes	No
		HRLD5095	LWUHRLD	45.7	5.50	408.0	14.40	11.20	11.20	CON	Yes	Yes	No
		Unit S-1 PSD Baseline	LWUS1B	18.3	1.50	428.0	10.40	-34.40	-34.40	EXP	No	Yes	No
		Unit S-2 PSD Baseline	LWUS2B	18.3	1.50	428.0	10.40	-34.40	-34.40	EXP	No	Yes	No
		Unit S-3 PSD Baseline	LWUS3B	34.5	2.10	416.0	16.00	-100.70	-100.70	EXP	No	Yes	No
		Unit S-4 PSD Baseline	LWUS4B	35.1	2.30	416.0	17.40	-139.90	-139.90	EXP	No	Yes	No
		Unit CT-1 PSD Baseline	LWUCT1B	14.0	4.90	720.0	24.90	-28.10	-28.10	EXP	No	Yes	No
		Diesels 1-5 PSD Baseline	LWUD15B	5.0	0.60	626.0	37.10	-1.50	-1.50	EXP	No	Yes	No
0990042	FPL Riviera												
		Units 3&4 at 2.5%s fuel oil	RIVU34	90.8	4.88	401.5	18.90	2113.65	2113.65	NO	Yes	No	No
0990026	Sugar Cane Growers^a												
		Unit 1&2	SUGCN12	45.7	1.87	339.0	21.75	41.20	41.20	CON	Yes	Yes	Yes
		Unit 3	SUGCN3	27.4	1.52	339.0	22.25	16.20	16.20	CON	Yes	Yes	Yes
		Unit 4 PSD	SUGCN4	54.9	2.44	339.0	21.73	38.20	38.20	CON	Yes	Yes	Yes
		Unit 5	SUGCN5	45.7	2.30	339.0	15.94	27.90	27.90	CON	Yes	Yes	Yes
		Unit 8 PSD	SUGCN8	47.2	2.90	339.0	13.62	23.50	23.50	CON	Yes	Yes	Yes
		Unit 1&2 PSD Baseline	SUGCN12B	24.4	1.40	344.0	11.40	-24.20	-24.20	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	SUGCN3B	24.4	1.60	344.0	15.60	-4.40	-4.40	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	SUGCN4B	25.9	1.63	344.0	11.20	-24.20	-24.20	EXP	No	Yes	Yes
		Unit 5 PSD Baseline	SUGCN5B	24.4	1.40	344.0	15.20	-16.20	-16.20	EXP	No	Yes	Yes
		Unit 6&7 PSD Baseline	SUGCN67B	12.2	1.52	606.0	11.20	-51.00	-51.00	EXP	No	Yes	Yes
0990061	US Sugar-Bryant^a												
		Unit 5 PSD	USSBRY5	42.7	2.90	345.0	11.49	45.70	45.70	CON	Yes	Yes	Yes
		Unit 1,2&3	USBRY123	19.8	1.64	342.0	36.40	109.50	109.50	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	USSBRY1B	19.8	1.68	494.0	44.30	-36.50	-36.50	EXP	No	Yes	Yes
		Unit 2&3 PSD Baseline	USBRY23B	19.8	1.68	344.0	37.90	-73.00	-73.00	EXP	No	Yes	Yes
0510003	US Sugar - Clewiston - PSD Baseline												
		Unit 1	BRL1	50.3	2.44	347.0	19.20	79.86	37.06	CON	Yes	Yes	Yes
		Unit 2	BLR2	50.3	2.44	338.0	19.20	79.86	37.06	CON	Yes	Yes	Yes
		Unit 3	BLR3	50.3	2.44	333.2	10.91	48.30	48.31	CON	Yes	Yes	Yes
		Unit 4	BLR4	45.7	2.51	344.3	25.36	86.02	82.22	CON	Yes	Yes	Yes
		Unit 7	BLR7	68.6	2.59	405.4	25.97	17.39	15.81	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	BRL1B	23.1	1.86	344.0	30.20	-79.86	-58.21	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	BLR2B	23.1	1.86	343.0	35.70	-79.86	-58.21	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	BLR3B	27.4	2.29	342.0	14.70	-48.30	-33.20	EXP	No	Yes	Yes
		East Pellet Plant PSD Baseline	EPELLET	12.2	1.52	347.0	8.54	-10.30	-10.30	EXP	No	Yes	Yes
		West Pellet Plant PSD Baseline	WPELLET	15.7	1.52	347.0	8.54	-10.30	-10.30	EXP	No	Yes	Yes

[a] Facilities or sources within facilities that operate only during the November 1 through March 31 crop season

[b] Sugar mill sources that operate all year

Note: EXP = PSD expanding source.
CON = PSD consuming source.
NO = Source does not affect PSD increment.

Table 6-8. Summary of SO_2 Facilities That Were Included in the PSD Class I Incremental Modeling Analysis

AIRS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to Everglades National Park X (km)	Relative to Everglades National Park Y (km)	Relative to Everglades National Park Distance (km)	Relative to Everglades National Park Direction (deg)
0250348	Dade Co. Resource Recovery	Dade	564.3	2857.4	14.0	8.8	16.5	58
0250020	Tarmac	Dade	562.9	2861.7	12.6	13.1	18.2	44
0112119	South Broward Resource Recovery	Broward	579.6	2883.3	29.3	34.7	45.4	40
0110037	FPL -Fort Lauderdale	Broward	580.1	2883.3	29.8	34.7	45.7	41
0112120	North Broward Resource Recovery	Broward	583.6	2907.6	33.3	59.0	67.7	29
0710019	Lee County Resource Recovery	Lee	424.0	2946.0	-30.0	82.0	87.3 [a]	340
0990332	Okeelanta	Palm Beach	525.0	2937.4	-25.3	88.8	92.3	344
0710000	FPL - Fort Myers	Lee	422.1	2952.9	-31.9	88.9	94.5 [a]	340
0990016	Atlantic Sugar	Palm Beach	552.9	2945.2	2.6	96.6	96.6	2
0990026	Sugar Cane Growers	Palm Beach	534.9	2953.3	-15.4	104.7	105.8	352
0510001	Evercane Sugar	Hendry	509.6	2954.2	-40.7	105.6	113.2	339
0510003	US Sugar Clewiston	Hendry	506.1	2956.9	-44.2	108.3	117.0	338
0990234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	35.5	111.6	117.1	18
0990016	Osceola Farms	Palm Beach	544.2	2968.0	-6.1	119.4	119.6	357
0990061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	-11.5	119.5	120.1	355
0510015	Southern Gardens	Hendry	487.6	2957.6	-62.7	109.0	125.7	330
0990021	Pratt & Whitney	Palm Beach	559.2	2978.3	8.9	129.7	130.0	4
0850102	Bechtel Indiantown	Martin	545.6	2991.5	-4.7	142.9	143.0	358
0850001	FPL -Martin	Martin	543.1	2992.9	-7.2	144.3	144.5	357

[a] Distance from ENP's northwestern corner located at UTM location = 454.0 km E, 2864.0 km N

Table 6-9. Summary of PM Facilities Considered for Inclusion in the AAQS and PSD Class II Air Modeling Analyses

AIRS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to ASA [a] X (km)	Relative to ASA [a] Y (km)	Relative to ASA [a] Distance (km)	Relative to ASA [a] Direction (deg)	Maximum PM Emissions (TPY)	Q, (TPY) Emission Threshold [b] (Dist -7.5) x 20	Include in Modeling Analysis ?
990026	Sugar Cane Growers	Palm Beach	534.9	2953.3	-18.0	8.1	19.7	294	1,032	314.8	YES
990016	Osceola Farms	Palm Beach	544.2	2968.0	-8.7	22.8	24.4	339	700	408.1	YES
990061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	-14.1	22.9	26.9	328	979	457.9	YES
990332	Okeelanta	Palm Beach	525.0	2937.4	-27.9	-7.8	29.0	254	283	499.4	NO
990086	Glades Correctional Institute	Palm Beach	523.4	2955.2	-29.5	10.0	31.1	289	30	543.0	NO
990021	Pratt & Whitney	Palm Beach	559.2	2978.3	6.3	33.1	33.7	11	30	593.9	NO
500234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	32.9	15.0	36.2	65	26	573.2	NO
500045	Lake Worth Utilities	Palm Beach	592.8	2943.7	39.9	-1.5	39.9	92	468	648.6	NO
500042	FPL -Riviera Beach	Palm Beach	594.2	2960.6	41.3	15.4	44.1	70	3,340	731.6	YES
510001	Everglades Sugar	Hendry	509.6	2954.2	-43.3	9.0	44.2	282	41	804.5	NO
850102	Bechtel Indiantown	Martin	545.6	2991.5	-7.3	46.3	46.9	351	270	857.4	NO
510003	US Sugar Clewiston	Hendry	506.1	2956.9	-46.8	11.7	48.2	284	2,190	884.8	YES
112120	North Broward Resource Recovery	Broward	583.6	2907.6	30.7	-37.6	48.5	141	103	820.8	NO
850001	FPL -Martin	Martin	543.1	2992.9	-9.8	47.7	48.7	348	7,578	893.9	YES
	[a] Atlantic Sugar Association East and North Coordinates (km)		552.9	2945.2							

[b] Proposed project's maximum 24-hour emissions are significant to 7.5 km.
Emission inventory is limited to facilities within 57.5 km of the ASA facility.

Table 6-10. Summary of PM Sources Included in the Air Modeling Analysis

AIRS Number	Facility	Units	ISCST3 ID Name	Stack Parameters: Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s)	PSD Source? (EXP/CON)	Modeled in: AAQS	Class II
0990016	Atlantic Sugar^a										
		Unit 1	ATLSUG1	27.4	1.83	346.0	17.97	10.58	CON	Yes	Yes
		Unit 2	ATLSUG2	27.4	1.83	350.0	23.36	10.58	CON	Yes	Yes
		Unit 3	ATLSUG3	27.4	1.83	350.0	21.56	9.83	CON	Yes	Yes
		Unit 4	ATLSUG4	27.4	1.83	344.0	25.16	10.05	CON	Yes	Yes
		Unit 5 PSD	ATLSUG5	27.4	1.68	339.0	19.24	4.50	CON	Yes	Yes
		Unit 1 PSD Baseline	ATLSUG1B	18.9	1.92	506.0	12.70	-14.74	EXP	No	Yes
		Unit 2 PSD Baseline	ATLSUG2B	18.9	1.92	511.0	10.90	-17.89	EXP	No	Yes
		Unit 3 PSD Baseline	ATLSUG3B	21.9	1.83	522.0	17.50	-9.32	EXP	No	Yes
		Unit 4 PSD Baseline	ATLSUG4B	18.3	1.83	344.0	15.00	-9.25	EXP	No	Yes
0990026	Sugar Cane Growers^a										
		Unit 1&2	SUGCN12	45.7	1.87	339.0	21.75	6.49	CON	Yes	Yes
		Unit 3	SUGCN3	27.4	1.52	339.0	22.25	12.95	CON	Yes	Yes
		Unit 4 PSD	SUGCN4	54.9	2.44	339.0	21.73	12.45	CON	Yes	Yes
		Unit 5	SUGCN5	45.7	2.30	339.0	15.94	12.45	CON	Yes	Yes
		Unit 8 PSD	SUGCN8	47.2	2.90	339.0	13.62	8.57	CON	Yes	Yes
		Unit 1&2 PSD Baseline	SUGCN12B	24.4	1.40	344.0	11.40	18.94	EXP	No	Yes
		Unit 3 PSD Baseline	SUGCN3B	24.4	1.60	344.0	15.60	-5.70	EXP	No	Yes
		Unit 4 PSD Baseline	SUGCN4B	25.9	1.63	344.0	11.20	-10.90	EXP	No	Yes
		Unit 5 PSD Baseline	SUGCN5B	24.4	1.40	344.0	15.20	-9.10	EXP	No	Yes
		Unit 6&7 PSD Baseline	SUGCN67B	12.2	1.52	606.0	11.20	-2.50	EXP	No	Yes
0990019	Osceola Farms^a										
		Unit 2	OSBLR2	27.4	1.52	339.0	18.63	7.06	CON	Yes	Yes
		Unit 3	OSBLR3	27.4	1.92	344.0	14.34	7.36	CON	Yes	Yes
		Unit 4	OSBLR4	27.4	1.83	344.0	16.53	10.58	CON	Yes	Yes
		Unit 5	OSBLR5	27.4	1.52	344.0	17.85	8.09	CON	Yes	Yes
		Unit 6	OSBLR6	27.4	1.92	339.0	18.25	7.17	CON	Yes	Yes
		Unit 1 PSD Baseline	OSBLR1B	22.0	1.52	342.0	8.18	-3.38	EXP	No	Yes
		Unit 2 PSD Baseline	OSBLR2B	22.0	1.52	341.0	18.10	-7.52	EXP	No	Yes
		Unit 3 PSD Baseline	OSBLR3B	22.0	1.93	341.0	14.50	-4.03	EXP	No	Yes
		Unit 4 PSD Baseline	OSBLR4B	22.0	1.83	341.0	18.80	-6.01	EXP	No	Yes
		Unit 5 PSD Baseline	OSBLR5B	22.0	1.52	342.0	12.12	-6.01	EXP	No	Yes
0990061	US Sugar - Bryant^a										
		Unit 5 PSD	USSBRY5	42.7	2.90	345.0	11.49	12.59	CON	Yes	Yes
		Unit 1,2&3	USBRY123	19.8	1.64	342.0	36.40	43.66	CON	Yes	Yes
		Unit 1 PSD Baseline	USSBRY1B	19.8	1.68	494.0	44.30	-82.40	EXP	No	Yes
		Unit 2&3 PSD Baseline	USBRY23B	19.8	1.68	344.0	37.90	-12.04	EXP	No	Yes

Table 6-10. Summary of PM Sources Included in the Air Modeling Analysis

AIRS Number	Facility	Units	ISCST3 ID Name	Stack Parameters: Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s)	PSD Source? (EXP/CON)	Modeled in: AAQS	Class II
	FPL - Riviera Beach										
		Units 3 and 4 at 2.5% S fuel oil	RIVU34	90.8	4.88	401.5	18.90	96.08	NO	Yes	No
	US Sugar - Clewiston										
		Unit 1	BLR1	50.3	2.44	347.0	19.20	14.52	CON	Yes	Yes
		Unit 2	BLR2	50.3	2.44	338.7	19.20	14.52	CON	Yes	Yes
		Unit 3	BLR3	50.3	2.44	333.2	10.91	12.02	CON	Yes	Yes
		Unit 4	BLR4	45.7	2.51	344.3	25.36	10.55	CON	Yes	Yes
		Unit 7	BLR7	68.6	2.59	405.4	25.97	2.79	CON	Yes	Yes
		Unit 1 PSD Baseline	BRL1B	23.1	1.86	344.0	30.20	-7.48	EXP	No	Yes
		Unit 2 PSD Baseline	BLR2B	23.1	1.86	343.0	35.70	-7.04	EXP	No	Yes
		Unit 3 PSD Baseline	BLR3B	27.4	2.29	342.0	14.70	-4.57	EXP	No	Yes
		East Pellet Plant PSD Baseline	EPELLET	12.2	1.52	347.0	8.54	-1.69	EXP	No	Yes
		West Pellet Plant PSD Baseline	WPELLET	15.7	1.52	347.0	8.54	-0.82	EXP	No	Yes
		Units 5&6 PSD Baseline	BLR56B	23.1	1.86	494.0	44.30	-52.92	EXP	No	Yes
0850001	FPL - Martin										
		Units 1&2	MART12	152.1	7.99	420.9	21.03	218.00		Yes	No
		Aux Blr PSD	MARTAUX	18.3	1.10	535.4	15.24	-	CON	Yes	Yes
		Diesel Gens PSD	MARTGEN	7.6	0.30	785.9	39.62	-	CON	Yes	Yes
		Units 3&4 PSD	MART34	64.9	6.10	410.9	18.90	15.30	CON	Yes	Yes

a Facilities or sources within facilities that operate only during the November 1 through March 31 crop season

b. Sugar mill sources that operate all year

Note: EXP = PSD expanding source

CON = PSD consuming source

NO = Source does not effect PSD increment.

Table 6-11. Summary of CO Facilities Considered for Inclusion in the AAQS Air Modeling Analyses

AIRS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to ASA [a] X (km)	Relative to ASA [a] Y (km)	Distance (km)	Direction (deg)	Maximum CO Emissions (TPY)	Q, (TPY) Emission Threshold [b] (Dist -20) x 20	Include in Modeling Analysis ?
990026	Sugar Cane Growers	Palm Beach	534.9	2953.3	-18.0	8.1	19.7	294	33,771	194.8	YES
990016	Osceola Farms	Palm Beach	544.2	2968.0	-8.7	22.8	24.4	339	25,175	288.1	YES
990061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	-14.1	22.9	26.9	328	2,071	337.9	YES
990332	Okeelanta	Palm Beach	525.0	2937.4	-27.9	-7.8	29.0	254	3,289	379.4	YES
990086	Glades Correctional Institute	Palm Beach	523.4	2955.2	-29.5	10.0	31.1	289	10	423.0	NO
990021	Pratt & Whitney	Palm Beach	559.2	2978.3	6.3	33.1	33.7	11	30	473.9	NO
510001	Everglades Sugar	Hendry	509.6	2954.2	-43.3	9.0	44.2	282	15	684.5	NO
850102	Bechtel Indiantown	Martin	545.6	2991.5	-7.3	46.3	46.9	351	1,647	737.4	YES
510003	US Sugar Clewiston	Hendry	506.1	2956.9	-46.8	11.7	48.2	284	9,360	764.8	YES
850001	FPL -Martin	Martin	543.1	2992.9	-9.8	47.7	48.7	348	1,816	773.9	YES
[a] Atlantic Sugar Association East and North Coordinates (km)			552.9	2945.2							

[b] Proposed project's maximum 8- and 1-hour concentrations for CO are significant to 10 and 5 km, respectively. Emission inventory is limited to facilities within 60 km of ASA facility.

Table 6-12. Summary of CO Sources Included in the Air Modeling Analysis

Number	Facility	Units	ISCST3 ID Name	Stack Parameters: Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s)
0990016	Atlantic Sugar^a							
		Unit 1	ATLSUG1	27.4	1.83	346.0	17.97	242.68
		Unit 2	ATLSUG2	27.4	1.83	350.0	23.36	242.68
		Unit 3	ATLSUG3	27.4	1.83	350.0	21.56	294.84
		Unit 4	ATLSUG4	27.4	1.83	344.0	25.16	311.85
		Unit 5	ATLSUG5	27.4	1.68	339.0	19.24	209.11
08500102	Bechtel Indiantown PSD		BECHTIND	150.9	4.88	333.2	30.50	47.38
0850001	FPL Martin							
		Units 1&2	MART12	152.1	7.99	420.9	21.03	38.92
		Aux Blr PSD	MARTAUX	18.3	1.10	535.4	15.24	-
		Diesl Gens PSD	MARTGEN	7.6	0.30	785.9	39.62	-
		Units 3&4 PSD	MART34	64.9	6.10	410.9	18.90	26.66
0990332	Okeelanta^a							
		Okeelanta Power Blrs 1,2,3^b	OKCOGEN	68.6	3.05	438.7	17.46	94.61
0990019	Osceola Farms^a							
		Unit 2	OSBLR2	27.4	1.52	339.0	18.63	317.52
		Unit 3	OSBLR3	27.4	1.92	344.0	14.34	128.77
		Unit 4	OSBLR4	27.4	1.83	344.0	16.53	317.52
		Unit 5	OSBLR5	27.4	1.52	344.0	17.85	374.22
		Unit 6	OSBLR6	27.4	1.92	339.0	18.25	310.40
0990026	Sugar Cane Growers^a							
		Unit 1&2	SUGCN12	45.7	1.87	339.0	21.75	547.09
		Unit 3	SUGCN3	27.4	1.52	339.0	22.25	187.61
		Unit 4 PSD	SUGCN4	54.9	2.44	339.0	21.73	467.71
		Unit 5	SUGCN5	45.7	2.30	339.0	15.94	359.60
		Unit 8 PSD	SUGCN8	47.2	2.90	339.0	13.62	381.02
0990061	US Sugar-Bryant^a							
		Unit 5 PSD	USSBRY5	42.7	2.90	345.0	11.49	760.91
		Unit 1,2&3	USBRY123	19.8	1.64	342.0	36.40	1309.77
	US Sugar Clewiston^a							
		Unit 1	BRL1	50.3	2.44	347.0	19.20	811.79
		Unit 2	BLR2	50.3	2.44	338.0	19.20	811.79
		Unit 3	BLR3	50.3	2.44	333.2	10.91	430.92
		Unit 4	BLR4	45.7	2.51	344.3	25.36	518.43
		Unit 7	BLR7	68.6	2.59	405.4	25.97	71.62

a. Facilities or sources with facilities that operate only during the November 1 through April 30 crop season.
b. Sugar mill sources that operate all year.

Table 6-13. A Summary of Building Structures Considered in the Air Modeling Analysis

Structure	Height		Length		Width	
	ft	m	ft	m	ft	m
Boiler House	58	17.7	225	68.6	70	21.3
Mill Building	40	12.2	200	61.0	60	18.3
Boiling House	88	26.8	140	42.7	115	35.1

Table 6-14. ASA Mill Property Boundary Receptors Used in the Air Modeling Analysis

Direction (degrees)	Distance (m)	Direction (degrees)	Distance (m)
10	2,349	190	3,677
20	2,462	200	3,853
30	2,671	210	4,181
40	3,020	220	4,225
50	2,889	230	3,545
60	2,555	240	3,136
70	2,355	250	2,890
80	2,247	260	2,758
90	2,213	270	2,716
100	2,247	280	2,758
110	2,355	290	2,890
120	2,555	300	3,136
130	2,889	310	3,545
140	3,443	320	3,020
150	4,181	330	2,671
160	3,853	340	2,462
170	3,677	350	2,349
180	3,621	360	2,313

Note: Distances are relative to the Boiler No. 5 stack location.

Table 6-15. Everglades National Park Receptors Used in the PSD Class I Modeling Analysis

Receptor	Receptor UTM Coordinates (m) East	North	Receptor	Receptor UTM Coordinates (m) East	North
1	557000	2789000	27	540000	2848600
2	556600	2792000	28	535000	2848600
3	556000	2796000	29	530000	2848600
4	553000	2796500	30	525000	2848600
5	548000	2796500	31	520000	2848600
6	542700	2796500	32	514500	2848600
7	542700	2800000	33	514500	2843000
8	542700	2805000	34	514500	2838000
9	542700	2810000	35	514500	2832500
10	542000	2811000	36	510000	2832500
11	541300	2814000	37	505000	2832500
12	542700	2816000	38	500000	2832500
13	544100	2820000	39	495000	2832500
14	543500	2824600	40	494500	2837000
15	545000	2829000	41	491500	2841000
16	545700	2832200	42	488500	2845500
17	546200	2835700	43	483000	2848500
18	548600	2837500	44	480000	2852500
19	550300	2839000	45	475000	2854000
20	545000	2839000	46	473500	2857000
21	540000	2839000	47	473500	2860000
22	550500	2844000	48	469000	2860000
23	545000	2844000	49	464000	2860000
24	540000	2844000	50	459500	2863200
25	550300	2848600	51	454000	2863200
26	545000	2848600			

Note: ASA UTM East and North coordinates are 552900E, 2945200N

Table 6-16. Maximum Pollutant Impacts Predicted for the Proposed Project, Screening Analysis

Pollutant/ Averaging Time	Value	Concentration[a] ($\mu g/m^3$)	Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)	Significant Impact Level ($\mu g/m^3$)
SO_2						
Annual	Highest	0.314	300	3,136	87123124	1
		0.339	270	2,716	88123124	
		0.341	300	3,136	89123124	
		0.365	270	2,716	90123124	
		0.348	300	3,136	91123124	
24-Hour	Highest	16.7	70	2,355	87081224	5
		15.0	340	2,462	88021924	
		14.9	320	3,020	89011524	
		22.5	350	2,349	90071424	
		15.6	310	3,545	91061424	
3-Hour	Highest	82.7	90	2,213	87011324	25
		57.9	90	2,213	88042803	
		76.1	90	2,213	89092006	
		61.7	110	2,355	90072806	
		72.0	310	3,545	91061403	
PM10						
Annual	Highest	0.228	300	3,136	87123124	1
		0.210	300	3,136	88123124	
		0.228	300	3,136	89123124	
		0.222	300	3,136	90123124	
		0.239	300	3,136	91123124	
24-Hour	Highest	8.28	70	2,355	87081224	5
		7.39	360	2,313	88090524	
		7.05	300	3,136	89062324	
		11.13	350	2,349	90071424	
		7.74	310	3,545	91061424	
NOx						
Annual	Highest	0.445	300	3,136	87123124	1
		0.418	270	2,716	88123124	
		0.458	300	3,136	89123124	
		0.454	300	3,136	90123124	
		0.475	300	3,136	91123124	
CO						
8-Hour	Highest	981	120	2,555	87091408	500
		924	280	2,758	88073108	
		663	340	2,462	89070608	
		886	60	2,555	90080308	
		1,132	310	3,545	91061408	
1-Hour		2,842	90	2,213	87072824	2,000
		2,896	90	2,213	88080424	
		2,813	80	2,247	89081005	
		2,884	90	2,213	90080203	
		2,820	360	2,313	91080221	

[a] Based on 5-year meteorological record, West Palm Beach, 1987 to 1991

[b] Relative to Boiler Number 5 Stack Location

Legend:

YYMMDDHH = Year, Month, Day, Hour Ending

Table 6-17. Maximum Pollutant Impacts Predicted for the Proposed Project at the PSD Class I Area of the Everglades National Park

Pollutant/ Averaging Time	Value	Concentration[a] ($\mu g/m^3$)	UTM Coordinates (m) East	UTM Coordinates (m) North	Time Period (YYMMDDHH)	EPA Proposed Class I Significant Impact Levels ($\mu g/m^3$)
SO_2						
Annual	Highest	0.0012	545000	2848600	87123124	0.1
		0.0015	550300	2848600	88123124	
		0.0013	550300	2848600	89123124	
		0.0015	550300	2848600	90123124	
		0.0014	550300	2848600	91123124	
24-Hour	Highest	0.195	545000	2848600	87010924	0.2
		0.315	550300	2848600	88120824	
		0.199	514500	2848600	89062424	
		0.205	550300	2848600	90093024	
		0.385	520000	2848600	91101924	
3-Hour	Highest	1.46	545000	2848600	87010903	1.0
		2.52	550300	2848600	88120803	
		1.39	514500	2848600	89062403	
		1.48	545000	2848600	90040203	
		1.46	520000	2848600	91071624	
PM10						
Annual	Highest	0.00066	545000	2848600	87123124	0.2
		0.00079	545000	2848600	88123124	
		0.00068	550300	2848600	89123124	
		0.00083	550300	2848600	90123124	
		0.00083	545000	2848600	91123124	
24-Hour	Highest	0.085	545000	2839000	87090524	0.3
		0.093	545000	2848600	88100924	
		0.096	514500	2848600	89062424	
		0.099	550300	2848600	90093024	
		0.184	520000	2848600	91101924	
NOx						
Annual	Highest	0.001	545000	2848600	87123124	0.1
		0.002	550300	2848600	88123124	
		0.001	550300	2848600	89123124	
		0.002	550300	2848600	90123124	
		0.002	545000	2848600	91123124	

[a] Based on 5-year meteorological record, West Palm Beach, 1987 to 1991

Legend:
YYMMDDHH = Year, Month, Day, Hour Ending
PSD = Prevention of Significant Deterioration
NPS = National Park Service
EPA = Environmental Protection Agency

Table 6-18. Maximum Pollutant Impacts Predicted for All Future Sources, AAQS Screening Analyses

Pollutant/ Averaging Time	Value	Concentration[a] ($\mu g/m^3$)	Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)	Florida AAQS ($\mu g/m^3$)
SO_2						
Annual	Highest	7.60	350	2,349	87123124	60
		9.40	270	2,716	88123124	
		8.21	320	3,020	89123124	
		9.56	270	2,716	90123124	
		8.27	330	2,671	91123124	
24-Hour	HSH	70.3	350	2,349	87032724	260
		71.6	340	2,462	88012024	
		65.5	250	2,890	89011324	
		63.3	250	2,890	90030824	
		64.8	250	2,890	91111724	
3-Hour	HSH	266	350	2,349	87011624	1,300
		172	150	4,500	88030203	
		197	250	2,890	89011324	
		235	160	3,853	90012306	
		235	160	3,853	91012306	
PM_{10}						
Annual	Highest	2.98	350	2,349	87123124	50
		3.80	270	2,716	88123124	
		3.50	320	3,020	89123124	
		4.27	270	2,716	90123124	
		3.41	160	3,853	91123124	
24-Hour	HSH	60.0	350	2,349	87032724	150
		62.3	340	2,462	88012024	
		47.8	350	2,349	89030624	
		46.0	340	2,462	90031724	
		50.7	330	2,671	91112224	
CO						
8-Hour	HSH	3,391	350	2,349	87032708	10,000
		3,009	340	2,462	88012024	
		2,604	160	3,853	89110508	
		2,909	160	3,853	90121908	
		2,722	360	2,313	91012424	
1-Hour	HSH	10,368	30	2,671	87012101	40,000
		9,545	340	2,462	88022920	
		11,428	20	2,462	89121805	
		11,076	340	2,462	90031722	
		10,505	20	2,462	91122324	

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

[b] Relative to Boiler Number 5 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

HSH = Highest, 2nd-Highest Concentration in 5 years.

Table 6-19. Maximum Pollutant Impacts Predicted for All Future Sources For Comparison to AAQS, Refined Analysis

Pollutant/ Averaging Time	Value	Concentration ($\mu g/m^3$)			Receptor Location[b]		Time Period (YYMMDDHH)	Florida AAQS ($\mu g/m^3$)
		Total	Modeled	Background	Direction (degree)	Distance (m)		
SO_2								
Annual	Highest	14.6	9.6	5	270	2,716	90123124	60
24-Hour	HSH	96	83.1	13	338	2,350	88012024	260
3-Hour	HSH	313	266	47	350	2,350	87011624	1300
PM_{10}								
Anuual	Highest	24	4.3	20	268	2,700	90123124	50
24-Hour	HSH	103	67.0	36	338	2,500	88012024	150
CO								
8-Hour	HSH	6,724	3,391	3,333	350	2,350	87032708	10,000
1-Hour	HSH	17,196	11,641	5,555	18	2,500	89032601	40,000

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

[b] Relative to Boiler Number 5 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 6-20. Maximum Predicted Pollutant PSD Class II Increment Consumption, Screening Analysis

Pollutant/ Averaging Time	Value	Concentration[a] ($\mu g/m^3$)	Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)	Allowable PSD Class II Increment ($\mu g/m^3$)
SO_2						
24-Hour	HSH	17.8	340	12,500	87031324	91
		18.8	350	12,500	88010524	
		21.1	330	12,500	89020924	
		17.2	340	12,500	90011324	
		18.0	350	12,500	91123024	
3-Hour	HSH	62.7	20	10,000	87031503	512
		67.2	350	12,500	88022521	
		66.1	300	12,500	89022806	
		65.7	310	12,500	90012224	
		68.3	320	12,500	91121512	
PM_{10}						
24-Hour	HSH	4.10	120	4,000	87081124	30
		4.86	280	4,000	88073124	
		5.49	300	4,000	89080124	
		3.56	280	4,000	90091224	
		5.20	310	4,000	91100524	

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

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

HSH = Highest, 2nd-Highest Concentration in 5 years.

PSD = Prevention of Significant Deterioration

Table 6-21. Maximum Predicted SO_2 PSD Increment at the Everglades National Park PSD Class I Area

Averaging Time	Value	Concentration[a] ($\mu g/m^3$)	UTM Coordinates (m) East	UTM Coordinates (m) North	Time Period (YYMMDDHH)	Allowable PSD Class I Increment ($\mu g/m^3$)
24-Hour	HSH	1.61	545000	2848600	87010424	5
		2.10	540000	2848600	88122524	
		1.76	469000	2860000	89113024	
		1.97	542000	2811000	90012224	
		2.36	530000	2848600	91022524	
3-Hour	HSH	12.9	545000	2848600	87010406	25
		15.6	535000	2848600	88021621	
		14.0	545000	2848600	89020224	
		17.4	540000	2848600	90012224	
		12.5	550300	2848600	91070709	

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

Legend:
PSD = Prevention of Significant Deterioration
YYMMDDHH = Year, Month, Day, Hour Ending
UTM = Universal Transverse Mercator
HSH = Highest, 2nd-Highest

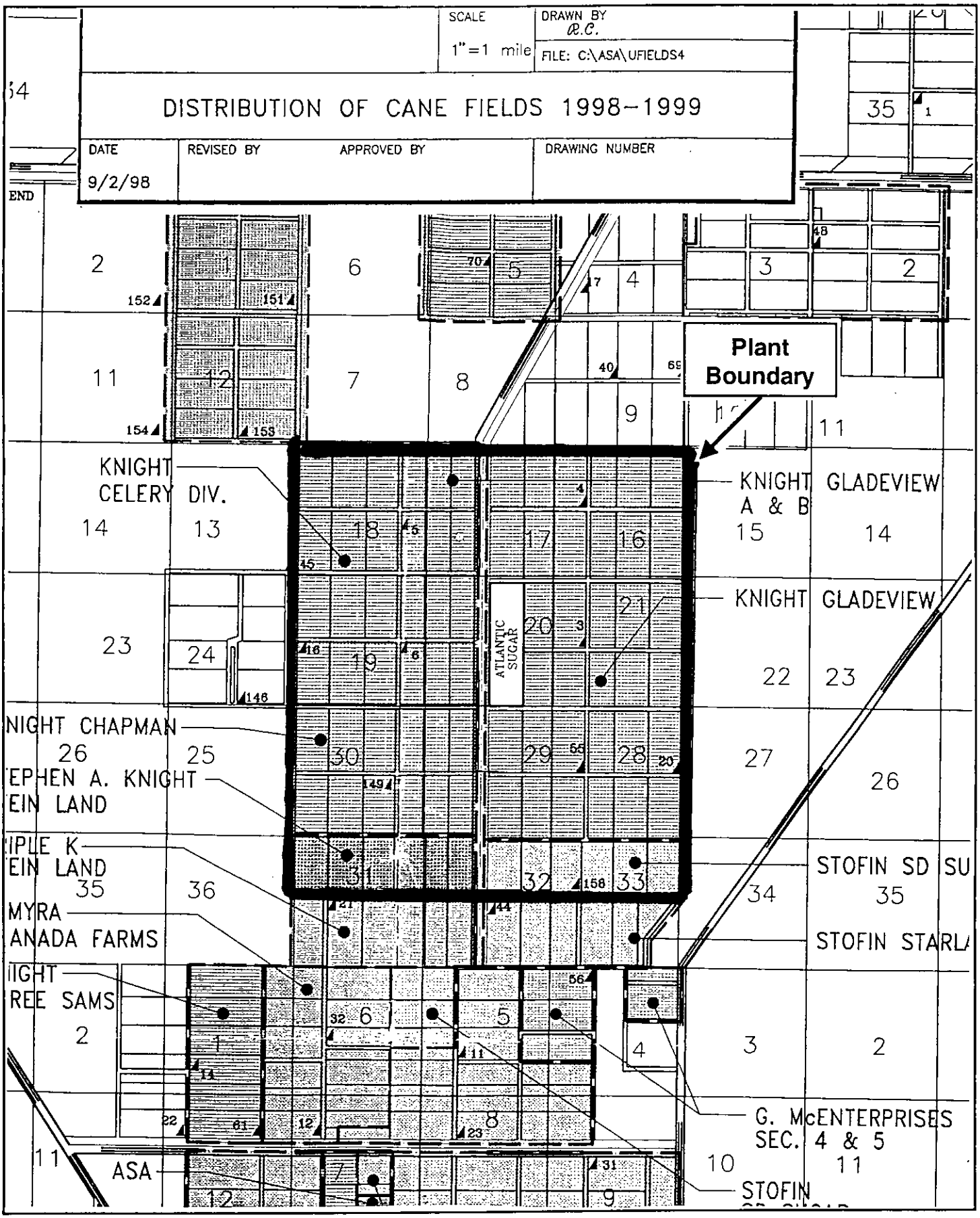


Figure 6-1. Plant Boundary
Atlantic Sugar Association, Inc.

Golder Associates

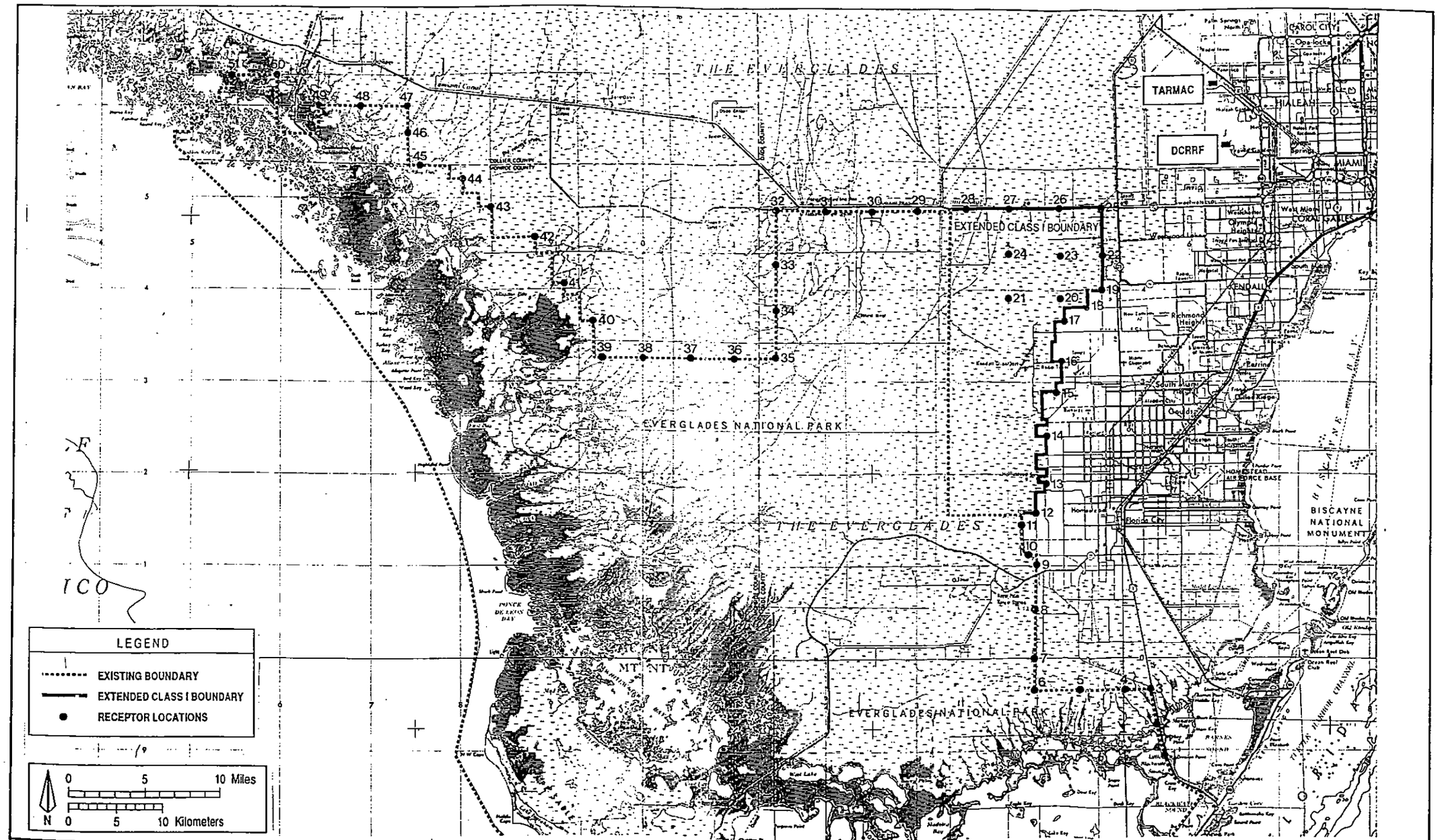


Figure 6-2. Receptor Locations Used for the Everglades National Park PSD Class I Screening Analysis

Golder Associates

7.0 ADDITIONAL IMPACT ANALYSES

7.1 VICINITY OF ATLANTIC SUGAR MILL

7.1.1 VEGETATION AND SOILS

The primary vegetation, as well as agricultural crop, in the vicinity of the ASA sugar mill is sugar cane. The mill 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. The Loxahatchee National Wildlife Refuge is located several miles to the east of the mill.

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 which is very fertile.

As described in the air quality impact analysis (Section 6.0), the maximum predicted SO_2, NO_2, PM, and CO concentrations in the vicinity of the ASA site as a result of 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.

No significant impacts on growth in the area are expected as a result of this project. Boiler No. 5 is an existing boiler, and the proposed project is only to allow increased utilization of the boiler on an annual basis. No new construction will occur. A slight increase in truck traffic may occur due to a slight increase in overall sugar production at the facility.

The potential impacts of SO_2, NO_2, PM, and CO on soils, vegetation, and visibility in the Everglades National Park Class I area are addressed in the following sections.

7.2 PSD CLASS I AREA

This section focuses on the ecological effects of the proposed facility modification on Air Quality Related Values (AQRV), as defined under PSD regulations, in the Everglades National Park

(ENP). The ENP is the closest Class I area to the ASA mill, and is located approximately 97 km south of the ASA mill. The AQRVs are defined as being:

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

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

The maximum predicted atmospheric concentrations due to the increase in emissions resulting from the proposed project are presented in Table 7-1. As shown, the predicted increase in impacts is very low for all pollutants considered.

7.2.1 IMPACTS TO SOILS

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

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

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical

changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

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

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

7.2.2 IMPACTS TO VEGETATION

The maximum predicted gaseous concentrations ($\mu g/m^3$) of SO_2, NO_2, PM, and CO were used in the determination of impacts on vegetation. These compounds are believed to interact predominantly with foliage and this is considered the major route of entry into plants. In this assessment, 100 percent of the compound of interest was assumed to interact with the vegetation.

7.2.2.1 Sulfur Dioxide

Sulfur is an essential plant nutrient usually taken up as sulfate ions by the roots from the soil solution. When sulfur dioxide in the atmosphere enters the foliage through pores in the leaves, it reacts with water in the leaf interior to form sulfite ions. Sulfite ions are highly toxic. They interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, within the leaf, sulfite is oxidized to sulfate ions, which can then be used by the plant as a nutrient. Small amounts of sulfite may be oxidized before they prove harmful.

SO_2 gas at elevated levels has long been known to cause injury to plants. Acute SO_2 injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercostal necrotic areas that appear water-soaked and dullish green initially. This injury generally occurs to younger leaves. Chronic injury usually is evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis (EPA, 1982). Background levels of SO_2 range from 2.5 to 25 $\mu g/m^3$. Observed SO_2 effect levels for several plant species and plant sensitivity groupings are presented in Tables 7-2 and 7-3, respectively.

Many studies have been conducted to determine the effects of high-concentration, short-term SO_2 exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are injured by exposure to 3-hour SO_2 concentrations of 790 to 1,570 $\mu g/m^3$. Intermediate plants include locust and sweetgum. These species are injured by exposure to 3-hour SO_2 concentrations of 1,570 to 2,100 $\mu g/m^3$. Resistant species (injured at concentrations above 2,100 $\mu g/m^3$ for 3 hours) include white oak and dogwood (EPA, 1982).

A study of native Floridian species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to 1,300 $\mu g/m^3$ SO_2 for 8 hours were not visibly damaged. This finding support the levels cited by other researchers on the effects of SO_2 on vegetation. A corroborative study (McLaughlin and Lee, 1974) demonstrated that approximately 20 percent of a cross-section of plants ranging from sensitive to tolerant was visibly injured at 3-hour SO_2 concentrations of 920 $\mu g/m^3$.

Two lichen species indigenous to the park area exhibited signs of SO_2 damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to 400 $\mu g/m^3$ for 6 hours/week for 10 weeks (Hart et al., 1988).

When the 8-hour modeled incremental SO_2 increase from the proposed modification (~~1.34~~ 0.95 $\mu g/m^3$) is added to the upper range of background SO_2 concentrations (0.72 $\mu g/m^3$), a maximum of ~~2.06~~ 1.7 $\mu g/m^3$ of SO_2 would be expected at the point of maximum impact in the

Everglades National Park. On comparison of this concentration to those causing injury to native species, it is evident that SO_2-sensitive species (or more tolerant species) would not be damaged by the predicted concentrations. By comparing the SO_2 concentration of 1.7 $\mu g/m^3$ with the concentrations that cause plant injury, it can be shown that the amount of SO_2 in the park area is only 1 percent of the most conservative concentration (200 $\mu g/m^3$) that caused injury to SO_2-sensitive species.

The 24-hour and annual SO_2 concentrations predicted within the park due to the project only (0.39 and 0.0067 $\mu g/m^3$, respectively) when added to background concentrations of 0.72 and 0.13 $\mu g/m^3$, respectively, result in total SO_2 impacts of 1.1 and 0.14 $\mu g/m^3$, respectively. These levels are much lower than those known to cause damage to test species. Jack pine seedlings exposed to SO_2 concentrations of 470 to 520 $\mu g/m^3$ for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 $\mu g/m^3$ SO_2 for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979). By comparison of these levels, it is apparent that the modeled 24-hour incremental increase of SO_2 is well below (i.e., less than 2 percent) the concentrations that caused damage in SO_2-sensitive plants. The modeled annual incremental increase in SO_2 (0.0067 $\mu g/m^3$) adds slightly to background levels of this gas and poses only a minimal threat to area vegetation.

7.2.2.2 Nitrogen Dioxide

Nitrogen dioxide (NO_2) is another emission of concern for the proposed plant expansion. This compound 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 (1, 4, 8 hours) exposure caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 $\mu g/m^3$ (Heck and Tingey, 1979).

Chronic exposure of selected plants (some considered NO_2-sensitive) to NO_2 concentrations of 2,000 to 4,000 $\mu g/m^3$ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975).

By comparison of published toxicity values for NO_2 exposure to short-term (i.e., 1-, 3-, and 8-hour averaging times) and long-term (annual averaging time) modeled concentrations, the possibility of plant damage in the park can be examined for both acute and chronic exposure situations, respectively. The 1-, 3-, and 8-hour estimated NO_2 concentrations due to the project only at the point of maximum impact in the park area are 4.3, 1.4, and 0.7 $\mu g/m^3$, respectively. These concentrations are approximately 0.02 to 0.10 percent of the levels that could potentially injure 5 percent of the plant foliage. For a chronic exposure, the annual estimated NO_2 concentration due to the project only at the point of maximum impact in the park (0.005 $\mu g/m^3$) is 0.00025 to 0.0005 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 park are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

7.2.2.3 Particulate Matter

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

By comparison of published toxicity values for PM exposure (i.e., 8-hour averaging time) concentrations, the possibility of plant damage in the park due to the project can be determined.

The 8-hour estimated PM concentration due to the project only at the point of maximum impact in the park area is 0.4 $\mu g/m^3$. This concentration is approximately 0.1 to 0.2 percent of the values that affected plant foliage. The extremely small additional impact the proposed project is predicted to have on the ENP will not cause any adverse affects to vegetation.

7.2.2.4 Carbon Monoxide

As with PM, information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome *c* oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome *c* oxidase depletes the supply of ATP, the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok et al. (1989) reported that exposure to $CO:O_2$ ratio of 25 (equivalent to an ambient CO concentration of 6.85×10^6 $\mu g/m^3$) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik et al. (1992) reported cytochrome *c* oxidase inhibition in corn, sorghum, millet, and Guinea grass at $CO:O_2$ ratios of 2.5 (equivalent to an ambient CO concentration of 6.85×10^5 $\mu g/m^3$). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase. The predicted annual average CO impact due to the proposed project only at the ENP (0.13 $\mu g/m^3$) is well below these published effects levels.

7.2.3 SUMMARY

In summary, the phytotoxic effects on the ENP from proposed increase in ASA Boiler No. 5 emissions are expected to be minimal. It is important to note that the substances were evaluated with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

7.3 IMPACTS TO WILDLIFE

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary ambient air quality standards. Physiological and behavioral effects have been observed in experimental animals at or below

these standards. No observable effects to fauna are expected at concentrations below the values reported in Table 7-4.

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

For impacts on wildlife, the lowest threshold values of SO_2, NO_x, and particulates which are reported to cause physiological changes are shown in Table 7-4. These values are up to orders of magnitude larger than maximum predicted concentrations for the Class I area. No effects on wildlife AQRVs from SO_2, NO_x, and particulates 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 REGIONAL HAZE

7.4.1.1 Introduction

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

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

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

b_{extb} is the background extinction coefficient.

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

The modeling analysis determined the deciview change at the Everglades National Park, a PSD Class I area located 97 km from the ASA mill.

7.4.2 ANALYSIS METHODOLOGY

Following the recommendations of the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II report, a level II screening analysis was performed using the California Puff (CALPUFF) long-term transport model, along with an enhanced ISC meteorological data record. The CALPUFF postprocessor model CALPOST was used to summarize the maximum concentrations of SO_4, NO_3, and PM_{10} that were predicted with the CALPUFF model.

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

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

- Use of five pollutant species of SO_2, SO_4, NO_x, HNO_3, and NO_3
- Use of MESOPUFF II scheme for chemical transformation with CALPUFF default background concentrations
- Include both dry and wet deposition and plume depletion
- Use Agricultural, unirrigated land use; minimum mixing height of 50 m
- Use transitional plume rise, stack-tip downwash, and partial plume penetration
- Use puff plume element dispersion, PG /MP coefficients, rural mode, and ISC building downwash scheme

- Use partial plume path adjustment terrain effects
- Use highest concentrations predicted in 5 years for comparison to deciview criteria

7.4.3 EMISSION INVENTORY

Based on recommendations of the IWAQM Phase II Report, the increase in emissions due to ASA's proposed Boiler No. 5 modification only were used in the air modeling analysis. For the CALPUFF analysis, the current Boiler No. 5's SO_2, NO_x and PM_{10} emissions were included as offsets against Boiler No. 5's future emission. Boiler No. 5 future maximum emissions were used. Therefore, the emission rates used in the CALPUFF analysis for Boiler No. 5 are 8.41 g/s for SO_2; 8.04 g/s for NO_x, and 4.50 g/s for PM_{10} (refer to Table 6-2).

7.4.4 BUILDING WAKE EFFECTS

The air modeling analysis included the ASA mill's 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.

7.4.5 RECEPTOR LOCATIONS

Receptors were located along a circle that was centered over the ASA mill and with a radius equal to the minimum distance between the ASA mill and ENP. The circle was comprised of 180 polar receptors, spaced at 2-degree intervals. Because the area's terrain is flat, all receptors were assumed to be at the ASA mill's elevation.

7.4.6 BACKGROUND VISUAL RANGES AND RELATIVE HUMIDITY FACTORS

Annual background extinction coefficients and relative humidity adjustment factors were provided by the National Park Service Air Quality Division for the ENP. The background extinction coefficient was based on data representative of the mean of the top 20-percentile air quality days. The following table summarizes the annual information. The background B_{ext} of 0.0464 inverse megameters (Mm^{-1}) is equivalent to a background visual range of 84 km.

Summary of Regional Haze Analysis Data for ENP		
Modeled Area	**Relative Humidity Factor**	**Background B_{ext} (Mm^{-1})**
Everglades National Park	3.85	0.0464

7.4.7 METEOROLOGICAL DATA

A 5-year data record was used which consisted of hourly surface observations and twice-daily mixing height data obtained from the Palm Beach International Airport National Weather Service(NWS) office. The data record was for the years 1987 through 1991. The surface and upper data were preprocessed into an ASCII modeling format by EPA's PCRAMMET meteorological preprocessing program. An anemometer height of 6.7 m was used for the modeling analysis.

Additional meteorological parameters were added to the meteorological data records for use with the CALPUFF model. The additional parameters include friction velocity, Monin-Obukhov length, and surface roughness used for calculating dry deposition; precipitation type code and precipitation rate used for calculating wet deposition, and short-wave solar radiation and relative humidity use for calculating chemical transformation rates. The dry deposition parameters were added to the meteorological data records using the PCRAMMET model in dry deposition mode. Using the guidance provided in Section 3.1 of the PCRAMMET User's Manual (8/98), the following input values were selected:

1. Surface roughness at both application and measurement sites: 0.15 m
2. Noontime Albedo: 0.14
3. Bowen Ratio: 0.8
4. Anthropogenic Heat flux: 0
5. Minimum Monin-Obukhov Length: 2 m
6. Fraction of Net Radiation Absorbed by Ground: 0.15

Hourly precipitation amounts, relative humidity and short-wave radiation values were added separately to the meteorological data set. These parameters were obtained from the West Palm Beach surface data available from Solar and Meteorological Surface Observation Network (SAMSON) data.

Based on the precipitation classification scheme provided in the CALPUFF Users Manual (Table 2-11) (7/95), each hour's precipitation code was set to 0 or 2. An hour in which no precipitation occurred received a code of 0. If precipitation occurred the code was set to 2. All precipitation is in the form of rain.

7.4.8 CHEMICAL TRANSFORMATION

Conservative chemical transformation assumptions were assumed for the air modeling analysis. It is assumed that all NO_x emissions are initially NO_2. The CALPUFF model is then used to predict SO_4, NO_3, and PM_{10} concentrations. A concentration of $4(NH_4)SO_4$ was estimated from the predicted SO_4 concentration by multiplying the SO_4 concentration by 1.375. This factor is the ratio of the two substances' molecular weights. Similarly, a concentration of NH_4NO_3 was estimated from the predicted NO_3 concentration by multiplying the NO_3 concentration by 1.29.

7.5 RESULTS

The results of the Level II screening analysis are summarized in Table 7-5. The predicted change in visibility of 1.21 percent is well below the criteria of 5 percent or 0.5 deciview. Therefore, it is concluded that the proposed project will not result in a significant impact on the visibility at the ENP.

Table 7-1. Maximum Predicted Concentrations Due To Project Only at Everglades National Park

Pollutant	Concentrations ($\mu g/m^3$) for Averaging Times [a]				
	Annual	24-Hour	8-Hour	3-Hour	1-Hour
Sulfur Dioxide (SO_2)	0.0067	0.39	0.95	2.52	4.46
Nitrogen Dioxide (NO_2)	0.0047	0.37	0.70	1.42	4.27
Particulate Matter (PM_{10})	0.0023	0.21	0.39	0.80	2.39
Carbon Monoxide (CO)	0.1270	9.60	18.10	37.00	110.90

[a] From the ISCST3 model using 1-hour current and future maximum emission rates for all averaging times, with 5 years of hourly meteorlogical data from West Palm Beach, 1987-91.

Table 7-2. SO_2 Effects Levels for Various Plant Species

Plant Species	Observed Effect Level (□g/m^3)	Exposure (Time)	Reference
Sensitive to tolerant	920 (20 percent displayed visible injury)	3 hours	McLaughlin and Lee, 1974
Lichens	200-400	6 hr/wk for 10 weeks	Hart *et al.*, 1988
Cypress, slash pine, live oak, mangrove	1,300	8 hours	Woltz and Howe, 1981
Jack pine seedlings	470-520	24 hours	Malhotra and Kahn, 1978
Black oak	1,310	Continuously for 1 week	Carlson, 1979

Table 7-3. Sensitivity Groupings of Vegetation Based on Visible Injury at Different SO_2 Exposures[a]

Sensitivity Grouping	SO_2 Concentration		Plants
	1-Hour	3-Hour	
Sensitive	1,310 - 2,620 $\mu g/m^3$ (0.5 - 1.0 ppm)	790 - 1,570 $\mu g/m^3$ (0.3 - 0.6 ppm)	Ragweed Legumes Blackberry Southern pines Red and black oaks White ash Sumacs
Intermediate	2,620 - 5,240 $\mu g/m^3$ (1.0 - 2.0 ppm)	1,570 - 2,100 $\mu g/m^3$ (0.6 - 0.8 ppm)	Maples Locust Sweetgum Cherry Elms Tuliptree Many crop and garden species
Resistant	>5,240 $\mu g/m^3$ (>2.0 ppm)	>2,100 $\mu g/m^3$ (>0.8 ppm)	White oaks Potato Upland cotton Corn Dogwood Peach

[a] Based on observations over a 20-year period of visible injury occurring on over 120 species growing in the vicinities of coal-fired power plants in the southeastern United States.

Source: EPA, 1982a.

Table 7-4. 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[1]	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[2,3]	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates[1]	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	continually for 2 months
	Decreased respiratory disease defenses in rats, same with hamsters	100 $NiCl_2$	2 hours

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

Table 7-5. Regional Haze Analyses for ASA Boiler No. 5 at the Everglades NP PSD Class I Area, IWAQM Level II Screening Analysis

Item	Units	Values
Predicted Concentration (a)	ug/m^3	
PM_{10}		0.107900
SO_4		0.01450
NO_3		0.030800
Calculated Concentrations	ug/m^3	
$(NH_4)_2SO_4$ (b)		0.0199
NH_4NO_3 (c)		0.0397
Everglades NP Background Data		
Relative Humidity Factor(d)		3.85
Background Extinction Coeff.(b_{ext}) (d)	Mm^{-1}	0.0464
Background Visual Range, Vr	km	84
Source Extinction Coeff (bexts)	km^{-1}	
$(NH_4)_2SO_4$ (e)		0.00023
NH_4NO_3 (e)		0.00046
PM_{10} (f)		0.00032
Total source b_{exts}	km^{-1}	0.00101
Percent Change in Visibility	%	2.16
Deciview Change		0.216

(a) Based on highest predicted 24-hour concentrations from CALPUFF model and 5-year enhanced meteorological data set for West Palm Beach (1987-91)

(b) Based on SO_4 concentration times 1.375.

(c) Based on NO_3 concentration times 1.29.

(d) Provided by NPS, Air Resources Div., Facimile of 5/26/99

(e) b_{ext} = Concentration * 0.003 * f(RH)

(f) b_{ext} = Concentration * 0.003

Ref: IWAQM Phase I Report (1993), Section 5.1.2, Inset 1, Appendix B
IWAQM Phase II Summary Report (12/98) Appendix B

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APPENDIX A

CURRENT PERMIT BOILER NO. 5

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NOTICE OF PERMIT ISSUANCE

RECEIVED
MAR 1[illegible] 1992
ATLANTIC [illegible]

CERTIFIED MAIL P 021 087 639
RETURN RECEIPT REQUESTED

In the Matter of an Application for Permit by:

Hector J. Cardentey
Assistant Vice President
Atlantic Sugar Association, Inc.
Post Office Box 1570
Belle Glade, Florida 33430

DER File No. AO50-205996
Palm Beach County - AP
Atlantic Sugar Association

Enclosed is Permit Number AO50-205996 to operate Boiler No. 5, issued pursuant to Section(s) 403.087, Florida Statutes.

A person whose substantial interests are affected by this permit may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of receipt of this Permit. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;

(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;

(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and

(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this permit. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

This permit is final and effective on the date filed with the Clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition and conforms to Rule 17-103.070, F.A.C. Upon timely filing of a petition or a request for an extension of time this permit will not be effective until further Order of the Department.

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

Executed in Fort Myers, Florida.

STATE OF FLORIDA
DEPARTMENT OF
ENVIRONMENTAL REGULATION

Philip R. Edwards
Director of
District Management
South District Office
2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33901
(813) 332-6975

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT ISSUANCE and all copies were mailed by certified mail before the close of business on March 16, 1992 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT

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

Karen L. Healy (Clerk) 3/16/92 (Date)

PRE/AEL/jw

Enclosures

Copies furnished to:

Palm Beach County Public Health Unit

Florida Department of Environmental Regulation

South District • 2295 Victoria Avenue • Fort Myers, Florida 33901

Lawton Chiles, Governor — Carol M. Browner, Secretary

PERMITTEE:
Hector J. Cardentey
Assistant Vice President
Atlantic Sugar Association, Inc.
Post Office Box 1570
Belle Glade, Florida 33430

I.D. No: 52FTM50001605
Permit/Certification
Number: AO50-205996
Date of Issue: March 12, 1992
Expiration Date: March 12, 1997
County: Palm Beach
Latitude: 26° 37′ 42" N
Longitude: 80° 28′ 06" W
Section/Town/Range: 20/44S/39E
Project: Atlantic Sugar Assn.
Boiler No. 5

This permit is issued under the provisions of Chapter 403.087, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Rules 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the Department and made a part hereof and specifically described as follows:

Operate boiler No. 5 with a design steam production capacity of 130,000 lbs/hr (1 hour average) at 250 psig and 550° (1 hour average) fired with bagasse and supplemental No. 6 fuel oil. The boiler's average steam production rate shall not exceed 115,000 lbs/hr per 24 hour period (8:00 AM to 8:00 AM). Emissions are controlled by a Joy Turbulaire Impingement Scrubber.

Plant is located south of State Road 80, approximately 13 miles east southeast of Belle Glade, Palm Beach County, Florida.

Recycled Paper

PERMITTEE:
Atlantic Sugar Association

I.D. No.: 52FTM50001605
Permit/Cert. No.: AO50-205996
Date of Issue: March 12, 1992
Expiration Date: March 12, 1997

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "permit conditions" and are binding and enforceable pursuant to Sections 403.141, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

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

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

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

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

PERMITTEE:
Atlantic Sugar Association

I.D. No.: 52FTM50001605
Permit/Cert. No.: AO50-205996
Date of Issue: March 12, 1992
Expiration Date: March 12, 1997

GENERAL CONDITIONS:

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

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

a. Have access to and copy any records that must be kept under the conditions of the permit;
b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and
c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

a. a description of and cause of non-compliance; and
b. The period of non-compliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance. The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source, which are submitted to the Department, may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes

GENERAL CONDITIONS:

or Department rules, except where such use is prescribed by Section 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 17-3.051, shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard.

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

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

13. This permit also constitutes:
- X ( ) Determination of Best Available Control Technology (BACT)
- X ( ) Determination of Prevention of Significant Deterioration (PSD)
- ( ) Certification of compliance with State Water Quality Standards (Section 401, PL 92-500)
- ( ) Compliance with New Source Performance Standards

14. The permittee shall comply with the following:

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

(b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation), required by the permit, copies of all reports required by this permit, and

GENERAL CONDITIONS:

records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report or application unless otherwise specified by Department rule.

(c) Records of monitoring information shall include:

1. the date, exact place, and time of sampling or measurements;
2. the person responsible for performing the sampling or measurements;
3. the dates analyses were performed;
4. the person responsible for performing the analyses;
5. the analytical techniques or methods used;
6. the results of such analyses.

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

PERMITTEE:
Atlantic Sugar Association

I.D. No.: 52FTM50001605
Permit/Cert. No.: AO50-205996
Date of Issue: March 12, 1992
Expiration Date: March 12, 1997

SPECIFIC CONDITIONS:

1. Steam production shall not exceed 130,000 lbs/hr (1 hour average) of 250 psig and 550°F steam (1 hour average). Steam with a higher enthalpy (1 hour average) shall not be produced by this boiler without prior approval of the Department. The boiler's average steam production rate shall not exceed 115,000 lbs/hr per 24 hour period (8:00 AM to 8:00 AM). The boiler shall be equipped with instruments to continuously record steam production, temperature, and pressure. Steam parameter records shall be kept for a minimum of 5 years.

2. Heat input to this boiler shall not exceed 253 million BTU per hour (approximately 33 TPH wet bagasse) as determined by an energy balance that assumes the boiler is 55 percent efficient.

3. Heat input from No. 6 residual oil to this boiler shall not exceed 25.1 million BTU per hour. Approximately 168 gallons per hour of No. 6 oil will produce 25.1 million BTU per hour. The fuel oil system shall be equipped with an integrating fuel oil flow meter or continuous recorder to measure the amount of fuel oil consumed by the boiler. The measuring device shall be calibrated annually by a method approved by the Bureau of Air Regulation.

4. The maximum allowable emissions from the No. 5 boiler shall be as follows: –

Pollutant	Max. Emission Rate ($lb/10^6$ BTU)*	Max. Emissions lbs/hour)	Test Method 40 CFR-60 Appendix A
Particulate Matter	0.15 (bagasse) 0.1 (fuel oil)	38	5
Sulfur Dioxide	0.30 (bagasse) 1.1 (fuel oil)	94	6, 6A, 6B
Nitrogen Oxides	0.16 (bagasse) 0.40 (fuel oil)	47	7, 7A, 7E
Volatile Organic Compounds	0.25 (bagasse)** 0.002 (fuel oil)	64	18, 25, 25A
Carbon Monoxide	6.50 (bagasse) 0.033 (fuel oil)	1645	10
Visible Emissions	30% opacity (6 minute average except 40% Opacity allowed for 2 minutes/hour)		9

PERMITTEE:
Atlantic Sugar Association

I.D. No.: 52FTM50001605
Permit/Cert. No.: AO50-205996
Date of Issue: March 12, 1992
Expiration Date: March 12, 1997

SPECIFIC CONDITIONS:

* When bagasse and oil are burned together, the allowable emissions are determined by pro-rating the standards for each fuel by the heat input.

** Subject to revision based on emissions test data obtained as a condition of this permit.

Compliance with the standards shall be determined by using any of the following EPA Reference Methods: 1, 2, 3, 4, 5, 6, 6A, 6B, 7, 7E, 8, 9, 10, 18, 25, and 25A as described in 40 CFR-60, Appendix A.

Excess emissions resulting from startup, shutdown, or malfunction of any source shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of the excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department (South Florida District) for longer duration (FAC 17-2.250). All startups, shutdowns, and malfunctions shall be recorded on the operating log for this boiler.

5. Visible emission from the bagasse handling system shall not exceed 10 percent opacity over any 6 minute period, as measured by EPA Referenced Method Nine, provided, however, that this visible emissions limit shall not apply during periods of high winds (wind speed of 18 miles per hour or greater) if reasonable precautions (covered conveyers, windbreaks, and the height of drop points are minimized) to control fugitive emissions have been taken. The company shall maintain a meteorological instrument to record the wind speed at the plant site.

6. Any No. 6 fuel oil burned in the No. 5 boiler shall contain no more than 1 percent sulfur. Compliance with this condition shall be determined from certified analysis of the replacement oil by ASTM Method D-1552. Records of the quantity and analysis of fuel oil consumed in the No. 5 boiler and invoices for the replacement oil purchased shall be kept for a minimum of 5 years.

7. The scrubber shall be equipped with manometer or equivalent instrument to measure the total pressure drop of the flue gas stream across the scrubber, with pressure gauges to measure the water pressure at the spray nozzles, and with a flow meter or equivalent device (weir) to measure the quantity of water circulating through the scrubber. The pH of the scrubber water at the scrubber inlet and outlet shall also be measured. Data from these instruments shall be recorded each shift (every 8 hours) and available to regulatory agencies for 5 years. During

SPECIFIC CONDITIONS:

particulate matter and sulfur dioxide compliance test, these parameters shall be recorded every 15 minutes. The boiler shall not be operated if the pressure is less than 35 psig on 14 spray nozzles and 60 psig on 24 spray nozzles, the flow through the scrubber is less than 550 GPM, the pressure drop across the scrubber is less than the values shown below:

Steam Production (1 hour average)	Minimum Pressure Drop
Up to 110,000 lbs/hr	6 inches water
110,000 - 115,000 lbs/hr	7 inches water
115,000 - 125,000 lbs/hr	8 inches water
125,000 - 130,000 lbs/hr	10 inches water

The restrictions on scrubber parameters are minimum allowable levels that apply except during startup, shutdown, and malfunction (limited 2 hours/24 hour period) or compliance testing.

These parameters may be changed by the Department (BAR) in the future if it can be shown that other values assure compliance.

8. Prior to expiration of this operation permit, a test shall be made on the No. 5 boiler to determine its actual thermal efficiency in accordance with the ASME short-form procedure. This test must be repeated each time the permit to operate this boiler is renewed (every 5 years). The tests shall be done while the tubes are clean and within 14 days of the compliance tests. A current report on the thermal efficiency test must be included with the application to renew the operating permit for this boiler.

9. Except as provided in Specific Condition 10, compliance test shall be conducted on Boiler No. 5 for each of the pollutants for which emission limits are prescribed in methods listed in Specific Condition No. 4. Such tests shall be conducted once per year commencing before February 15th, and the particulate matter and visible emission compliance testing shall be conducted simultaneously. Test results shall be submitted to the Department within 45 days after completion of compliance testing. The scrubber parameters listed in Specific Condition No. 7 that existed during the particulate matter and sulfur dioxide compliance tests shall be included in the test reports.

PERMITTEE:
Atlantic Sugar Association

I.D. No.: 52FTM50001605
Permit/Cert. No.: AO50-205996
Date of Issue: March 12, 1992
Expiration Date: March 12, 1997

SPECIFIC CONDITIONS:

10. Permittee may substitute an Operation and Maintenance plan that is approved by the Department (BAR) that optimizes the NO_X, CO, SO_2, and VOC emissions for the compliance test specified in Specific Condition Nos. 4 and 9, except particulate matter.

11. Operation of Boiler No. 5 shall not exceed 3000 hours per season and its steam production rate shall not exceed 130,000 lbs/hr (1 hour average) or 110 percent of the steam production rate that existed during the most recent Reference Method 5 test (annual compliance test submitted to the Department) demonstrating compliance with the particulate matter emissions limits, whichever is lower.

12. Permittee shall submit an annual emissions report for Boiler No. 5 which includes the quantity of oil burned in this boiler during the season and the sulfur content of replacement oil purchased.

13. Notification and reporting requirements of this permit shall also be sent to the Palm Beach County Health Department.

14. Stack sampling facilities provided by the owner shall be in accordance with the requirements of Chapter 17-2.700(4), Florida Administrative Code.

15. Continue to operate and maintain the quick release nozzles that have been installed, inspect them once daily and maintain a log of nozzle condition.

16. Maintain an operational sight glass on the scrubber with markings indicating the water level above or below the lip of the scrubber skirt.

17. Maintain the flow measurement device installed on the water supply line for the scrubber as well as the pressure drop alarm system.

18. Manually check, and record, once per week flue gas oxygen readings at the inlet of the scrubber using a portable oxygen instrument. Calibrate the oxygen instrument prior to each use to assure accurate readings.

PERMITTEE:
Atlantic Sugar Association

I.D. No.: 52FTM50001605
Permit/Cert. No.: AO50-205996
Date of Issue: March 12, 1992
Expiration Date: March 12, 1997

SPECIFIC CONDITIONS:

19. Obtain and record the water level above or below the scrubber skirt in inches once per day.

Note: In the event of an emergency the permittee shall contact the Department by calling (904)488-1320. During normal business hours, the permittee shall call (813)332-6975.

Issued this 12th day of March, 1992.

STATE OF FLORIDA
DEPARTMENT OF
ENVIRONMENTAL REGULATION

Philip R. Edwards
Director of
District Management

PRE/AEL/jw

13 Pages Attached

AIR OPERATING PERMIT AMENDMENTS

Florida Department of Environmental Regulation

South District • 2269 Bay Street • Fort Myers, Florida 33901-2896

Lawton Chiles, Governor

Carol M. Browner, Secretary

October 9, 1991

RECEIVED

OCT 14 1991

ATLANTIC SUGAR ASSOC.

Hector J. Cardentey
Assistant Vice President and
Environmental Director
Atlantic Sugar Association, Inc.
Post Office Box 1570
Belle Glade, Florida 33430

Re: Palm Beach County - AP
Atlantic Sugar Association, Inc.

Dear Mr. Cardentey:

Thank you for your letter of October 2, regarding wood chip burning. We agree that burning untreated wood chips in your boilers will probably not increase emissions.

This letter authorizes you to burn untreated wood chips in your existing boilers.

Thank you for consulting us about this matter.

Sincerely,

Philip R. Edwards
Director of
District Management

PRE/DMK/jw

cc: Palm Beach County Public Health Unit

cc: Diego - WJC.
Tria - Lee

AIR CONSTRUCTION PERMIT

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

PERMITTEE:
Atlantic Sugar Association
P. O. Drawer B
Belle Glade, Florida 33430

Permit Number: AC 50-107181
Expiration Date: June 30, 1986
County: Palm Beach
Latitude/Longitude: 26° 37' 44"N/
80° 28' 06"W
Project: No. 5 Boiler Modifications

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

Authorization to increase steam production in the existing No. 5 bagasse-fired (No. 6 oil supplementary fuel) boiler which is equipped with an impingement type scrubber, from 100,000 to 130,000 lbs of 250 psig/500°F steam per hour. The No. 5 boiler is located at Atlantic Sugar Association's existing sugar mill that is approximately 4 miles south of Belle Glade, Palm Beach County, on State Road 80. The UTM coordinates of the proposed plant are zone 17, 552.9 km E and 2945.2 km N.

The modification shall be in accordance with the attached permit application, plans, documents, and drawing except as noted in the specific conditions of this permit.

Attachments are as follows:

1. Application to Construct Air Pollution Sources, DER form 17-1.202(1), October 21, 1985.
2. July 16, 1985, Hopping, Boyd, Green and Sams letter.
3. August 9, 1985, Department letter.
4. October 17, 1985, Atlantic Sugar Association letter.
5. November 8, 1985, Department letter.
6. November 18, 1985, Atlantic Sugar Association letter.
7. December 6, 1985, Department letter.
8. December 16, 1985, Atlantic Sugar Association letter.

GENERAL CONDITIONS:

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

c. Records of monitoring information shall include:

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

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

SPECIFIC CONDITIONS:

1. Steam production shall not exceed 130,000 lb/hr (1 hr/avg) of 250 psig and 500°F steam. The boiler may operate for up to 6 hrs per day at 130,000 lb/hr. The boiler's average steam production rate shall not exceed 115,000 lb/hr during any calendar day. Steam with a higher enthalpy shall not be produced by this boiler without prior approval of the department. The boiler shall be equipped with an instrument to continuously record steam production. Steam production records shall be kept for a minimum of 5 years.

PERMITTEE:
Atlantic Sugar Association

Permit Number: AC 50-107181
Expiration Date: June 30, 1986

SPECIFIC CONDITIONS:

2. Heat input to this boiler shall not exceed 252.65 million Btu per hour as determined by an energy balance that assumes the boiler is 55 percent efficient. Approximately 32.8 TPH of wet bagasse will produce 252.65 million Btu per hour.

3. Heat input from No. 6 residual oil to this boiler shall not exceed 25.1 million Btu per hour. Approximately 168 gallons per hour of No. 6 oil will produce 25.1 million Btu per hour. The fuel oil system shall be equipped with an intergrating fuel oil flow meter or continuous recorder to measure the amount of fuel oil consumed by the boiler. The measuring device shall be calibrated annually by a method approved by the department.

4. The maximum allowable emissions from the No. 5 boiler shall be as follows:

Pollutant	Max. Emission Rate ($lb/10^6$ Btu) *	Max. Emissions (lb/hr)
Particulate Matter	0.15 (bagasse) 0.1 (fuel oil)	37.9
Sulfur Dioxide	0.29 (bagasse) 2.6 (fuel oil)	93.6
Nitrogen Oxides	0.16 (bagasse) 0.40 (fuel oil)	46.5
Volatile Organic Compounds	0.10 (bagasse) 0.00 (fuel oil)	25.3
Carbon Monoxide	0.27 (bagasse) 0.007 (fuel oil)	68.2
Visible Emissions	20% Opacity (6 minute average except 40% opacity allowed for 2 minutes per hour	

* Compliance with the standards shall be determined by EPA Reference Methods 1, 2, 3, 4, 5, 6, 7, 9, 10 and 25 as described in 40 CFR 60, Appendix A.

SPECIFIC CONDITIONS:

5. Visible emissions from the bagasse handling system shall not exceed 10 percent opacity over any 6 minute period as measured by EPA Reference Method 9.

6. Any No. 6 fuel oil burned in the No. 5 boiler shall contain no more than 2.4 percent sulfur and shall be replaced during the season in which it was burned with fuel oil containing no more than 1 percent sulfur. Compliance with this condition shall be determined from certified analysis of the replacement oil by ASTM Method D-1552. Records of the quantity and analysis of fuel oil consumed in the No. 5 boiler and invoices for the replacement oil purchased shall be kept for a minimum of 5 years.

7. The scrubber shall be equipped with a manometer or equivalent instrument to measure the total pressure drop of the flue gas stream across the scrubber, with pressure gauges to measure the water pressure at the spray nozzles, and with a flow meter or equivalent device (weir) to measure the quantity of water circulating through the scrubber. The pH of the scrubber water at the scrubber inlet and outlet shall also be measured. Data from these instruments shall be recorded each shift (every 8 hours) and available to regulatory agencies for 5 years. During compliance tests, these parameters shall be recorded every 15 minutes. The boiler shall not be operated if the pressure drop across the scrubber is less than 7 inches of water, the pressure on the spray nozzles is less than 35 psig on 14 spray nozzles and 60 psig on 24 spray nozzles, and the flow through the scrubber is less than 550 GPM. These parameters may be increased in the future if higher values are needed to assure compliance.

8. Prior to the expiration of this construction permit, a test shall be made on the No. 5 boiler to determine its actual thermal efficiency in accordance with the ASME short-form procedure. This test must be repeated each time the permit to operate this boiler is renewed (every 5 years). The tests shall be done while the tubes are clean and within 14 days of the compliance tests. A current report on the thermal efficiency test must be included with the application for permit to operate this boiler.

9. Compliance with all emission standards for the No. 5 boiler, except particulate matter and visible emissions, may be based on emission factors established by previous EPA reference method tests on this boiler. As a condition of this construction permit, particulate matter and visible emissions tests shall be conducted concurrently on the boiler while it is operating at its maximum or permitted capacity, whichever is lower. Any permit to operate issued

SPECIFIC CONDITIONS:

for this boiler will restrict production to the quantity that existed during the compliance tests. The compliance tests results shall be calculated by assuming the thermal efficiency of the boiler is 55 percent, or by any new method subsequently adopted by department rule. For information purposes only, the particulate matter emission rate shall also be calculated by utilizing both the F factor and the actual boiler efficiency as determined by the latest ASME boiler efficiency test. The scrubber parameters listed in Specific Condition No. 7 that existed during the compliance test shall be included in the test report. The South Florida District office shall be notified 15 days prior to any compliance test.

10. After the initial reference method tests that showed compliance with the allowable emission standards for this boiler, the company may substitute an Operation and Maintenance plan that is approved by the department that optimizes the NO_x, CO, SO_2, and VOC emissions for the compliance tests specified in Specific Conditions Nos. 4 and 9.

11. The permittee will demonstrate compliance with the conditions of this construction permit and submit a complete application for permit to operate to the South Florida District office at least 90 days prior to the June 30, 1986, expiration date of this construction permit or 60 days after the No. 5 boiler reaches its maximum or permitted steam production rate, whichever date occurs first. A copy of the initial emission tests report for all regulated air pollutants shall be sent to the Bureau of Air Quality Management. The permittee may continue to operate in compliance with all terms of this construction permit until its expiration date. Commercial operation of this boiler is not authorized unless it is in compliance with all conditions in the applicable permits.

12. Any permit to operate issued for the No. 5 boiler shall limit its operations to 3,000 hours per season and the steam production capacity to that which existed during the Reference Method 5 test, require (as a minimum) annual particulate matter and visible emissions tests, and an annual operation report which includes the quantity of oil burned in this boiler during the season and sulfur content of the replacement oil purchased.

PERMITTEE:
Atlantic Sugar Association

Permit Number: AC 50-107181
Expiration Date: June 30, 1986

SPECIFIC CONDITIONS:

Issued this_____day of_____, 19__

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL REGULATION

_____
VICTORIA J. TSCHINKEL, Secretary

____ pages attached.

RECEIVED FEB 1 3 1986

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

WIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

February 4, 1986

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. Jose F. Alvarez
General Manager
Atlantic Sugar Association
Post Office Drawer B
Belle Glade, Florida 33430

Dear Mr. Alvarez:

Attached is one copy of the Technical Evaluation and Preliminary Determination, and proposed permit that will authorize an increase in steam production of the No. 5 bagasse-fired boiler.

Before final action can be taken on your permit, you are required by Florida Administrative Code Rule 17-103.150 to publish the attached Notice of Proposed Agency Action in the legal advertising section of a newspaper of general circulation in Palm Beach County no later than fourteen days after receipt of this letter. The DER Bureau of Air Quality Management must be provided with proof of publication within seven days of the date the notice is published. Failure to publish the notice may be grounds for denial of the permit.

The Bureau has been notified that violation of the air pollution control regulations exist at this plant. The department cannot issue a permit to increase the steam production of the boiler if it or any associated equipment is in violation of the regulations. Please be advised that the issuance of a construction permit is contingent on your company correcting any violations and settling any enforcement action associated with this boiler and its accessory equipment.

Technical Evaluation
and
Preliminary Determination

Atlantic Sugar Association
Belle Glade, Florida
Palm Beach County

No. 5 Bagasse-Fired Boiler Modification
File No. AC 50-107181

Florida Department of Environmental Regulation
Bureau of Air Quality Management
Central Air Permitting

February 5, 1986

Table I

Pollutant	Present Production (a) max. lb/hr	TPY(g)	Proposed Production (b) max. lb/hr(c)	TPY(d)	Change lb/hr	TPY
Particulate Matter (e)	29.2	51.4	37.9	50.3	+8.7	-1.1
Sulfur Dioxide(f)	106.1	167.8	93.6	124.1	-12.5	-43.7
Carbon Monoxide(e)	53.1	93.7	68.2	90.5	+15.1	-3.2
Hydrocarbon(e)	53.1	93.7	25.3(h)	38.0	-27.8	-55.7
Nitrogen Oxides(f)	36.5	56.3	46.5	61.7	+10.0	+5.4

(a) 3,528 hr/season maximum allowed operation
(b) 3,000 hr/season maximum allowed operation
(c) 130,000 lb/hr maximum hourly steam production allowed
(d) 115,000 lb/hr maximum daily average steam producted allowed
(e) Boiler using 100 percent bagasse fuel
(f) Boiler using bagasse with No. 6 oil as supplementary fuel
(g) From the Public Notice for Construction Permit No. AC 50-42389
(h) Allowable hydrocarbon emissions are reduced to the potential emissions as specified in Specific Condition No. 13 of Construction Permit No. AC 50-42389

II. RULE APPLICABILITY

A. State Regulations

The proposed project, increasing the steam production from an existing carbonaceous fuel fired boiler (No. 6 oil supplementary fuel) located at a sugar mill, is subject to preconstruction review under the provisions of Chapter 403, Florida Statutes, and Chapter 17-2, Florida Administrative Code.

The affected boiler is located in an area designated nonattainment for ozone (Rule 17-2.410, FAC), and attainment for the other criteria pollutants (17-2.420).

Sugar mills, which are chemical process plants, are listed in Table 500-2, Major Facility Categories (list of 28). The sugar mill is a major facility (17-2.100) because the emissions of particulate matter (PM), sulfur dioxide (SO_2) carbon monoxide (CO), volatile organic compounds (VOC), and nitric oxides (NO_X) exceed 100 TPY for each of these criteria pollutants. However, the increase in emissions resulting from the proposed project are less than the significant emission rates listed in Table 500-2, Regulated Air Pollutants-Significant Emission Rates.

The project is not subject to the prevention of signficant deterioration regulations (17-2.500) and new source review for nonattainment areas (17-2.510) because the modification does not result in a significant emission increase of any criteria pollutant (17-2.500(2)(d)4.a(ii) and 17-2.510(2)(d)4.a.).

The project will be reviewed under Rule 17-2.520, Sources Not Subject to Prevention of Significant Deterioration or Nonattainment Requirements. Allowable emissions will be based on the best available control technology (BACT) determination issued for this source when it was originally constructed by the applicant and the emissions currently being proposed by the applicant. Higher emissions could subject this modification to review under other regulations.

B. Federal Regulations

The proposed project, a minor modification to a major source, is not subject to review under federal regulations because the modification will not result in a significant net emissions increase of any criteria pollutant. The permit the state proposes to issue in response to the applicant's request will succeed the federal permit (PSD-FL-078) that was originally issued to Atlantic Sugar Association for this boiler although any condition in the federal permit that is not modified by the state permit will remain in effect and be enforceable by the regulatory agencies.

III. Technical Evaluation

The emission standards in the initial permit to construct (AC 50-42389) that was issued for the No. 5 boiler and Joy Turbulaire impingement type scrubber were based on BACT and LAER determinations. A BACT determination addressed all criteria pollutants except VOC. The VOC standard was established by a LAER determination. A reliable VOC emission factor for bagasse boilers was not available when the initial application to construct this boiler was processed. Based on the estimated emissions in the original application, it was necessary to assign 93.7 TPY new source allowance for VOC to this source. The department believed the VOC emission factor used by the applicant was high and, as a condition of the original construction permit (Specific Condition No. 13 of permit No. AC 50-42389), required any excess VOC new source allowance be returned to Palm Beach County. Actual test data on this boiler shows it will emit less than the significant emission rate of 40 TPY VOC after the modification. Under current state regulations, all 93.7 TPY of VOC from the new source allowance initially assigned to this boiler is returned to the new source allowance for Palm Beach County. If the VOC emissions from this boiler exceeds 40 TPY in the future, a new allowable VOC emission standard, based on a revised LAER determination, will be assigned to this boiler.

The maximum allowable emission rates from Specific Condition No. 2 of the original state construction permit are shown in Table II.

Table II

Pollutant	Burning Bagasse 100% lb/MMBtu	lb/hr	Burning Bagassee with Fuel Oil lb/MMBtu	lb/hr
PM	0.15	29.2	0.14	27.9
SO_2	0.49	95.1	0.55	106.1
CO	0.27	53.1	0.28	53.8
VOC	0.27	53.1	0.27	53.2
NOx	0.16	31.9	0.19	36.5

A recent BACT determination for a bagasse-fired boiler that has been issued since the No. 5 boiler was initially permitted was more restrictive than the BACT for boiler No. 5. The original emission rate standards (lb/MBtu) will not be relaxed in any permit revisions for this boiler. More details on the evaluation that established the original emission standards are in the August 28, 1981, Preliminary Determination for this boiler that is on file in the department's office in Ft. Myers and the Palm Beach County Health Department in West Palm Beach.

APPENDIX B

BOILER NO. 5 TEST DATA

Table B-1. Emission Tests Performed on Boiler No. 5, Atlantic Sugar Association

Unit	Test Date	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	SO2 Emissions (EPA Method 6)		PM Emissions (EPA Method 5)		CO Emissions (EPA Method 10)		NOx Emissions (EPA Method 7E)		VOC Emissions [2] (EPA Method 18/25A)		
					lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	
Boiler 5	02/15/93	114,200	215.60	29.94			30.09	0.140	1,108	5.14	18.90	0.088			
Boiler 5	02/15/93	104,600	198.10	27.51			26.50	0.134	1,438	7.26	15.10	0.076			
Boiler 5	12/16/93	116,800	215.80	29.97	0.21	0.0010			354	1.64	30.80	0.143			
Boiler 5	12/16/93	117,100	215.70	29.96	0.21	0.0010			899	4.17	16.40	0.076			
Boiler 5	12/16/93	116,000	214.20	29.75	0.19	0.0009			664	3.10	23.90	0.112			
Boiler 5	11/17/93	116,250	229.12	31.82											
Boiler 5	11/17/93	114,000	224.68	31.21											
Boiler 5	11/17/93	109,672	216.05	30.01											
Boiler 5	11/18/93	115,105	220.54	30.63											
Boiler 5	11/18/93	116,301	223.00	30.97											
Boiler 5	11/18/93	117,176	216.09	30.01											
Boiler 5	01/26/95	120,444	226.92	31.52			27.68	0.122	342	1.51	39.06	0.172			
Boiler 5	01/26/95	112,075	211.19	29.33			31.19	0.148	173	0.82	51.29	0.243			
Boiler 5	01/26/95	115,846	217.71	30.24			30.92	0.142	946	4.35	45.92	0.211			
Boiler 5	01/26/95	95,695	180.39	25.05			25.66	0.142	153	0.85	41.45	0.230			
Boiler 5	01/27/95	99,346	186.87	25.95			25.84	0.138	161	0.86	57.63	0.308			
Boiler 5	01/27/95	112,500	211.87	29.43			33.60	0.159	170	0.80	52.32	0.247			
Boiler 5	01/27/95	96,947	176.25	24.48			23.52	0.133	697	3.95	23.69	0.134			
Boiler 5	12/06/95	126,800	242.50	33.68	0.10	0.0004			213	0.88	30.90	0.127			
Boiler 5	12/06/95	123,600	235.90	32.76	0.29	0.0012			239	1.01	29.10	0.123			
Boiler 5	12/06/95	122,900	234.30	32.54	0.12	0.0005			200	0.85	27.90	0.119			
Boiler 5	12/06/95	122,160	232.90	32.35			28.97	0.124							
Boiler 5	12/06/95	117,300	223.70	31.07			24.79	0.111							
Boiler 5	12/06/95	126,800	242.50	33.68			24.25	0.100							
Boiler 5	01/08/97	124,300	237.90	33.04	0.13	0.0005	20.10	0.084	1,555	6.54	20.80	0.087	53.10	0.223	
Boiler 5	01/08/97	125,300	239.80	33.31	0.16	0.0007	22.60	0.094	1,462	6.10	22.60	0.094	53.60	0.224	0.23
Boiler 5	01/08/97	126,500	242.10	33.63	0.15	0.0006	21.80	0.090	1,457	6.02	19.40	0.080	59.30	0.245	
Boiler 5	01/13/98	122,200	237.10	35.60	0.52	0.0022	29.20	0.123	535	2.25	30.10	0.127	53.30	0.225	
Boiler 5	01/13/98	124,000	240.10	36.00	1.15	0.0048	28.10	0.117	466	1.94	32.50	0.135	49.10	0.204	0.21
Boiler 5	01/13/98	122,900	237.90	35.70	0.28	0.0012	27.30	0.115	476	2.00	32.90	0.138	48.60	0.204	
Boiler 5	12/04/98	119,500	219.30	32.90	1.03	0.0047	31.40	0.143	1,215	5.54	32.30	0.147	2.32	0.011	
Boiler 5	12/04/98	117,500	219.00	32.90	1.24	0.0057	21.40	0.098	744	3.40	27.00	0.123	2.80	0.013	0.012
Boiler 5	12/04/98	120,300	222.40	33.40	1.10	0.0049	23.60	0.106	1,288	5.79	22.40	0.101	2.97	0.013	
Number =		**33**	**33**	**33**	**15**	**15**	**21**	**21**	**24**	**24**	**24**	**24**	**9**	**9**	
Minimum =		**95,695**	**176.25**	**24.48**	**0.10**	**0.0004**	**20.10**	**0.084**	**153**	**0.80**	**15.10**	**0.076**	**2.32**	**0.011**	
Average =		**116,731**	**221.44**	**31.22**	**0.46**	**0.0020**	**26.60**	**0.122**	**706**	**3.20**	**31.02**	**0.143**	**36.12**	**0.151**	
Maximum =		**126,800**	**242.50**	**36.00**	**1.24**	**0.0057**	**33.60**	**0.159**	**1,555**	**7.26**	**57.63**	**0.308**	**59.30**	**0.245**	

Notes:

lb/hr = pounds per hour.

lb/MMBtu = pounds per million British thermal units.

lb/ton = pounds per ton.

MMBtu/hr = million British thermal units per hour.

TPH = tons per hour.

Footnotes:

[1] Assumed 3,600 Btu/lb average heat content for wet bagasse, except where noted.

[2] Reported as methane (CH4).

Table B-2. Summary of SO2 Emission Tests on Boiler No. 5 at Atlantic Sugar Association

Date	Run	Heat Input Rate (MMBTU/hr)	Bagasse Heating Value (a) (BTU/lb)	Bagasse Burning Rate (TPH)	Sulfur Content (b) (%)	Theoretical SO_2 Emissions (lb/hr)	Measured SO2 Emissions		Inherent SO_2 Removal Efficiency (%)
							lb/hr	lb/MMBtu	
12/16/93	1	215.8	3,600	30.0	0.05	59.9	0.21	0.0010	99.6
	2	215.7	3,600	30.0	0.05	59.9	0.21	0.0010	99.6
	3	214.2	3,600	29.8	0.05	59.5	0.19	0.0009	99.7
12/6/95	1	242.5	3,600	33.7	0.05	67.4	0.10	0.0004	99.9
	2	235.9	3,600	32.8	0.05	65.5	0.29	0.0012	99.6
	3	234.3	3,600	32.5	0.05	65.1	0.12	0.0005	99.8
1/8/97	1	238.0	3,600	33.1	0.05	66.1	0.13	0.0005	99.8
	2	240.0	3,600	33.3	0.05	66.7	0.16	0.0007	99.8
	3	242.0	3,600	33.6	0.05	67.2	0.15	0.0006	99.8
1/13/98	1	237.1	3,600	32.9	0.05	65.9	0.52	0.0022	99.2
	2	240.1	3,600	33.3	0.05	66.7	1.15	0.0048	98.3
	3	237.9	3,600	33.0	0.05	66.1	0.28	0.0012	99.6
12/4/98	1	219.3	3,600	30.5	0.05	60.9	1.03	0.0047	98.3
	2	219.0	3,600	30.4	0.05	60.8	1.24	0.0057	98.0
	3	222.4	3,600	30.9	0.05	61.8	1.10	0.0049	98.2
							Average =	0.0020	99.3
							Maximum =	0.0057	99.9

(a) Where actual bagasse analysis data not available, heating value of 3,600 Btu/lb was assumed.
(b) Where actual bagasse sulfur content data not available, 0.05 % S, wet basis, was assumed.

APPENDIX C

EMISSION FACTOR DOCUMENTATION

NONFOSSIL FUELED BOILERS

Emission Test Report
U.S. Sugar Company
Bryant, Florida

Project No.: 80-WFB-6

Prepared for

Environmental Protection Agency
Office of Air Quality Planning and Standards
Emission Measurement Branch
Research Triangle Park
North Carolina 27711

by

James A. Peters and Charles F. Duncan

Contract 68-02-2818, Work Assignment No. 25

May 1980

MONSANTO RESEARCH CORPORATION
DAYTON LABORATORY
1515 Nicholas Road
Dayton, Ohio 45407

SECTION 1

INTRODUCTION

The Bryant Mill of U.S. Sugar Corporation in Bryant, Florida was emission tested by Monsanto Research Corporation (MRC) for the U.S. Environmental Protection Agency (EPA) under Contract No. 68-02-2818, Work Assignment No. 25. The objective of the sampling program was to obtain emissions data from well-controlled sources within the nonfossil fuel boilers category that could possibly be used for the development of new source performance standards.

The field test work was monitored by Dan Bivins, Field Testing Section, Emission Measurement Branch, EPA. The sampling performed by MRC was directed by Charles F. Duncan as team leader. Gaseous and particulate emissions were determined at the outlet of the pollution control device serving Boiler #2. A composite sample of boiler feed was collected with each run so that a material balance could be attempted.

The sampling at the Bryant Mill was conducted by MRC during December 16-18, 1979. The collection methods employed were EPA Methods 1, 2, 3, 4, 5, 6, 7, and 9, with particulate sizing by Andersen cascade impactor.

Quality assurance/quality control in the sampling area covered such activities as instrument calibration, using standard or approved sampling methods, chain-of-custody procedures, and protocols for the recording and calculation of data. QA/QC in the analysis area involved using only validated analysis methods, periodic operator QC checking and training, sample QC by the use of splits, reference standards, and spikes, and interlaboratory audits.

SECTION 2

SUMMARY OF RESULTS

Pollutants which were measured for this emission test were particulate matter, particle size, CO_2, CO, SO_2, NO_x, and plume opacity. Table 1 presents the sampling and analysis schedule in condensed form.

TABLE 1. BRYANT PLANT SAMPLING AND ANALYSIS SCHEDULE

Sampling site	Total number of samples	Sample type	Sampling method	Minimum sampling time	Initial analysis	
					Type	Method
Scrubber outlet	3	Particulate matter	EPA 5	60 min		
Scrubber outlet	3	Particle-size distribution	Andersen			
Scrubber outlet	3	Integrated gas analysis	EPA 3		CO_2, O_2, CO	EPA 3
Scrubber outlet	3	SO_2	EPA 6, option 2	Same as Method 5		
Scrubber outlet	3 runs, 4 samples each	NO_x	EPA 7	15 min intervals		
Scrubber outlet	3	Opacity	EPA 9			
Scrubber outlet	3 samples, 2 fuel analyses each	ASTM			Ultimate analysis and heating value	ASTM

The Bryant Mill operates three waste-fired boilers fed with bagasse. The center boiler, Boiler #2, was tested. Boiler #2 utilizes dual scrubbers in parallel for pollution abatement. The outlet stack is located directly above the scrubbers.

Three test runs were performed, each consisting of 96 minutes of sampling time. Forty-eight traverse points were used, six points in each of the eight sampling ports. The first run was completed December 17. During the run, the boiler operated normally, in the range of 145,000 to 160,000 lb/hr of steam, until more than halfway through the test, when the bagasse feed was interrupted. The steam loading dropped to about 60,000 lb/hr and oil began to be burned. The test was interrupted several minutes after the drop in steam loading and was begun again after the bagasse feed rate and the boiler operation returned to normal almost 2 hours later. During the last several minutes of the test before the interruption, about 75 gal of oil was burned. Bagasse alone was burned the remainder of the run.

The remaining two runs of the test were completed on December 18. Through both runs the boiler operated normally and bagasse alone was burned. The steam loading ranged from 125,000 to 165,000 lb/hr, with an average of 151,000 lb/hr, in Run 2 and from 130,000 to 170,000 lb/hr, with an average of 144,000 lb/hr, in the third run. Both runs were within the normal operating range. During the third run, soot blowing was performed.

Tables 2 and 3 contain the summarized particulate emission data and stack gas parameters. Moisture in the stack gas was unusually high -- 32 percent H_2O. Integrated gas analysis results for each run are given in Table 4.

Table 5 contains a summary of the particle sizing results; each Andersen cascade impactor run was made after completing a Method 5 run. The #1 impactor test was discarded because the filter media was soaked with water. Due to the boiler #2 plume merging with the other boilers' plumes, opacity readings were not able to be made.

Samples for SO_2 emissions were taken concurrently with particulate emission runs by using the back half of the Method 5 train. Due to the very low sulfur content of the bagasse feed, emissions of SO_2 were below the detection limit (3.4 mg SO_2/m^3) of Method 6, and no data are presented.

Samples for NO_x emissions were collected just after each particulate emission test and are summarized in Table 6.

Composite fuel samples of bagasse were taken with each run from the conveyor feeding the boiler, and ultimate analysis and fuel values were determined. A fuel oil sample from run #1 was also collected and analyzed for fuel value. Table 7 presents the fuel analysis results.

A summary of boiler operating conditions during testing is given in Table 8. Average steam temperatures and pressures were determined by averaging 15-min readings in order to calculate steam enthalpy.

TABLE 2. PARTICULATE EMISSION DATA AND STACK GAS PARAMETERS, U.S. SUGAR-BRYANT MILL, DECEMBER 17-18, 1979 (ENGLISH UNITS)

Run number	Date	Time, min	Stack temperature, °F	Flow, dscfm	H_2O, %	Isokinetic, %	Emissions			
							Actual gr/dscf	Actual lb/hr	Actual lb/mm Btu	Corrected To 12% CO_2 gr/dscf
1	12/17/79	96	161	58,515	31.3	105.7	0.1298	65.1	0.3505	0.1442
2	12/18/79	96	164	58,720	33.1	105.6	0.1001	50.4	0.2547	0.1082
3	12/18/79	96	162	58,825	31.7	101.6	0.1135[a]	57.2	0.3014	0.1205[a]
Average		96	162	58,687	32.0		0.1145	57.6	0.3029	0.1243

[a]Run #3 included a soot blow.

TABLE 3. PARTICULATE EMISSION DATA AND STACK GAS PARAMETERS, U.S. SUGAR-BRYANT MILL, DECEMBER 17-18, 1979 (METRIC UNITS)

Run number	Date	Time, min	Stack temperature, °C	Flow, dncmpm	H_2O, %	Isokinetic, %	Emissions			
							Actual gr/dncm	Actual kg/hr	Actual kg/GJ	Corrected To 12% CO_2 gr/dncm
1	12/17/79	96	72	1,657	31.3	105.7	0.2971	29.5	0.1506	0.3301
2	12/18/79	96	73	1,663	33.1	105.6	0.2292	22.9	0.1097	0.2478
3	12/18/79	96	72	1,666	31.7	101.6	0.2599[a]	26.0	0.1307	0.2760[a]
Average		96	72	1,662	32.0		0.2621	26.1	0.1303	0.2846

[a]Run #3 included a soot blow.

TABLE 4. SUMMARY OF INTEGRATED GAS ANALYSES, U.S. SUGAR-BRYANT MILL, DECEMBER 17-18, 1979

Run number	Date	CO_2, %	CO, %	O_2, %	N_2, %	MW lb/lb mole
1	12/17/79	10.8	0.0	9.2	80.0	30.1
2	12/18/79	11.1	0.0	9.0	79.9	30.1
3	12/18/79	11.3	0.0	9.4	79.3	30.2
Average		11.1	0.0	9.2	79.7	30.1

TABLE 5. SUMMARY OF ANDERSEN PARTICLE SIZING RESULTS, U.S. SUGAR-BRYANT MILL, DECEMBER 17-18, 1979

Run No. 1

Discarded

Run No. 2

Flow rate = 0.927 acfm
Isokinetic rate = 107.1%

Stage	Size range	Percent in size range	Cumulative % <size range
Preimpactor	>10.50	3.99	94.55
0	>10.50	1.46	94.55
1	6.50 - 10.50	3.06	91.52
2	4.30 - 6.50	7.98	83.54
3	2.95 - 4.30	11.30	72.24
4	1.88 - 2.95	12.40	59.94
5	0.94 - 1.88	12.90	46.94
6	0.58 - 0.94	19.15	27.79
7	0.39 - 0.58	16.49	11.30
Filter	0.0 - 0.39	11.30	0

Run No. 3

Flow rate = 0.908 acfm
Isokinetic rate = 105.5%

Stage	Size range	Percent in size range	Cumulative % <size range
Preimpactor	>10.60	6.56	91.43
0	>10.60	2.01	91.43
1	6.60 - 10.60	4.28	87.14
2	4.40 - 6.60	7.47	79.67
3	3.00 - 4.40	8.66	71.01
4	1.90 - 3.00	8.66	62.35
5	0.96 - 1.90	10.48	51.87
6	0.59 - 0.96	20.60	31.27
7	0.40 - 0.59	16.68	14.59
Filter	0.0 - 0.40	14.59	0

Particle Sizing Summary

An eight stage Anderson Mark III impactor was used for particle sizing tests. cause of the presence of entrained water or highly saturated gases, it was decided utilize an impactor preseperator to protect the impactor substrates and jet stages from the effects of water. This was thought superior to heating the impactor cause heating may change the stage collection efficiencies.

A particle sizing test run was made immediately following each method 5 test run. The tests were conducted at the point of average velocity shown in the method run. The impactor was used with a method 5 sampling train modified for its use by the use of a flexible line between the probe and impingers. The impactor was placed in the stack at the nozzle end of the probe. Isokinetic sampling was maintained throughout the tests.

The run 1 impactor test has been discarded because the filter media was soaked with water. Exactly how this happened was unknown. Runs 2 and 3 appear to be very satisfactory however. The preweighed filters following jets stages 0 through seven were collected and placed in petri dishes. The preweighed back up filter following plate eight (not a jet stage) was also placed in a petri dish. The acetone wash of the preseperator, inlet cone, and top surface of plate zero was placed in a clean sample bottle marked "preimpactor". Although the individual weights of the preimpactor wash and the first filter (from jet stage 0) have been recorded in Table 1, these have been added together for sizing using the 0 stage cut point. Cut sizes (dp_{50}) have been determined from the enclosed data furnished by Anderson Samplers, Inc.

Field data sheets have been enclosed. Orsat information was obtained from integrated bag and Burrell analyzer. Moisture values were taken from the accompanying EPA - 5 test run.

Table 1. Anderson Mark III Sizing Summary

Run 2
Flow Rate = 0.927 ACFM
Isokinetic Rage = 107.1%

Stage	Size Range	Effective Cut Diameter	Final Weight mg	Initial Weight mg	Gain mg	% in Size Range	Cummulative % <Size Range
Preimpactor	>10.50	10.5	110.3755	110.3785	3.0	3.99	94.55
0	>10.50	10.5	131.8	130.7	1.1	1.46	94.55
1	6.50 - 10.50	6.5	122.5	120.3	2.3	3.06	91.52
2	4.30 - 6.50	4.3	137.4	131.4	6.0	7.98	83.54
3	2.95 - 4.30	2.95	128.8	120.3	8.5	11.30	72.24
4	1.88 - 2.95	1.88	140.4	131.1	9.3	12.40	59.84
5	0.94 - 1.88	0.94	130.7	121.0	9.7	12.90	46.94
6	0.58 - 0.94	0.58	145.2	130.8	14.4	19.15	27.79
7	0.39 - 0.58	0.39	132.4	120.0	12.4	16.49	11.30
Filter	0.0 - 0.39	-	252.0	243.5	8.5	11.30	0
					75.2		

Run 3
Flow Rate = 0.908 ACFM
Isokinetic Rate = 105.5%

Stage	Size Range	Effective Cut Diameter	Final Weight mg	Initial Weight mg	Gain mg	% in Size Range	Cummulative % <Size Range
Preimpactor	>10.60	10.6	103.8754	103.8682	7.2	6.56	91.43
0	>10.60	10.6	134.5	132.3	2.2	2.01	91.43
1	6.60 - 10.60	6.6	125.3	120.6	4.7	4.28	87.14
2	4.40 - 6.60	4.4	138.5	130.3	8.2	7.47	79.67
3	3.00 - 4.40	3.0	130.5	121.0	9.5	8.66	71.01
4	1.90 - 3.00	1.9	139.8	130.3	9.5	8.66	62.35
5	0.96 - 1.90	.96	131.9	120.4	11.5	10.48	51.87
6	0.59 - 0.96	.59	152.6	130.0	22.6	20.60	31.27
7	0.40 - 0.59	.40	138.7	120.4	18.3	16.68	14.59
Filter	0.0 - 0.40	-	260.2	244.2	16.0	14.59	0
					109.7		

RUN 2
RUN 3
Cumulative Pretest (wt)

Table 1.3-1. CRITERIA POLLUTANT EMISSION FACTORS FOR FUEL OIL COMBUSTION[a]

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e]		Filterable PM[f]	
	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING
Boilers > 100 Million Btu/hr										
No. 6 oil fired, normal firing (1-01-004-01), (1-02-004-01), (1-03-004-01)	157S	A	5.7S	C	47	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, normal firing, low NO_x burner (1-01-004-01), (1-02-004-01)	157S	A	5.7S	C	40	B	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, (1-01-004-04)	157S	A	5.7S	C	32	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, low NO_x burner (1-01-004-04)	157S	A	5.7S	C	26	E	5	A	9.19(S)+3.22	A
No. 5 oil fired, normal firing (1-01-004-05), (1-02-004-04)	157S	A	5.7S	C	47	B	5	A	10	B
No. 5 oil fired, tangential firing (1-01-004-06)	157S	A	5.7S	C	32	B	5	A	10	B
No. 4 oil fired, normal firing (1-01-005-04), (1-02-005-04)	150S	A	5.7S	C	47	B	5	A	7	B
No. 4 oil fired, tangential firing (1-01-005-05)	150S	A	5.7S	C	32	B	5	A	7	B
No. 2 oil fired (1-01-005-01), (1-02-005-01), (1-03-005-01)	157S	A	5.7S	C	24	D	5	A	2	A
No.2 oil fired, LNB/FGR, (1-01-005-01), (1-02-005-01), (1-03-005-01)	157S	A	5.7S	A	10	D	5	A	2	A

Table 1.3-3. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: A

Firing Configuration (SCC)	TOC[b] Emission Factor (lb/10^3 gal)	Methane[b] Emission Factor (lb/10^3 gal)	NMTOC[b] Emission Factor (lb/10^3 gal)
Utility boilers			
No. 6 oil fired, normal firing (1-01-004-01)	1.04	0.28	0.76
No. 6 oil fired, tangential firing (1-01-004-04)	1.04	0.28	0.76
No. 5 oil fired, normal firing (1-01-004-05)	1.04	0.28	0.76
No. 5 oil fired, tangential firing (1-01-004-06)	1.04	0.28	0.76
No. 4 oil fired, normal firing (1-01-005-04)	1.04	0.28	0.76
No. 4 oil fired, tangential firing (1-01-005-05)	1.04	0.28	0.76
Industrial boilers			
No. 6 oil fired (1-02-004-01/02/03)	1.28	1.00	0.28
No. 5 oil fired (1-02-004-04)	1.28	1.00	0.28
Distillate oil fired (1-02-005-01/02/03)	0.252	0.052	0.2
No. 4 oil fired (1-02-005-04)	0.252	0.052	0.2
Commercial/institutional/residential combustors			
No. 6 oil fired (1-03-004-01/02/03)	1.605	0.475	1.13
No. 5 oil fired (1-03-004-04)	1.605	0.475	1.13
Distillate oil fired (1-03-005-01/02/03)	0.556	0.216	0.34
No. 4 oil fired (1-03-005-04)	0.556	0.216	0.34
Residential furnace (A2104004/A2104011)	2.493	1.78	0.713

[a] To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12. SCC = Source Classification Code.

[b] References 29-32. Volatile organic compound emissions can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

Table 1.3-11. EMISSION FACTORS FOR METALS FROM UNCONTROLLED NO. 6 FUEL OIL COMBUSTION[a]

Metal	Average Emission Factor[b, d] ($lb/10^3$ Gal)	EMISSION FACTOR RATING
Antimony	5.25E-03[c]	E
Arsenic	1.32E-03	C
Barium	2.57E-03	D
Beryllium	2.78E-05	C
Cadmium	3.98E-04	C
Chloride	3.47E-01	D
Chromium	8.45E-04	C
Chromium VI	2.48E-04	C
Cobalt	6.02E-03	D
Copper	1.76E-03	C
Fluoride	3.73E-02	D
Lead	1.51E-03	C
Manganese	3.00E-03	C
Mercury	1.13E-04	C
Molybdenum	7.87E-04	D
Nickel	8.45E-02	C
Phosphorous	9.46E-03	D
Selenium	6.83E-04	C
Vanadium	3.18E-02	D
Zinc	2.91E-02	D

[a] Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.

[b] References 64-72. 18 of 19 sources were uncontrolled and 1 source was controlled with low efficiency ESP. To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12.

[c] References 29-32,40-44.

[d] For oil/water mixture, reduce factors in proportion to water content of the fuel (due to dilution). To adjust the listed values for water content, multiply the listed value by 1-decimal fraction of water (ex: For fuel with 9 percent water by volume, multiply by 1-0.9=.91).

Table 1. Summary of Mercury Test Results for Okeelanta and Osceola

Source	Date	Boiler Type	Heat Input (MMBtu/hr)	Mercury Emissions lb/hr	Mercury Emissions lb/MMBtu	Mercury Emissions lb/ton*
Okeelanta						
Boiler 10	2/5/93	Cell	236.19	0.00353	1.49E-05	1.27E-04
Boiler 10	2/5/93	Cell	230.16	0.00126	5.47E-06	4.65E-05
Boiler 10	2/6/93	Cell	239.50	<0.00145	<6.05E-06	<5.15E-05
Boiler 10	2/6/93	Cell	235.34	<0.00133	<5.65E-06	<4.80E-05
Boiler 10	2/6/93	Cell	232.28	<0.00126	<5.42E-06	<4.61E-05
Boiler 10	2/6/93	Cell	223.60	<0.00137	<6.13E-06	<5.21E-05
Boiler 12	3/19/92	Traveling grate	310.45	0.00462	1.49E-05	1.26E-04
Boiler 12	3/19/92	Traveling grate	315.81	0.00019	6.05E-07	5.14E-06
Boiler 12	3/19/92	Traveling grate	304.49	0.00119	3.91E-06	3.32E-05
Boiler 14	1/15/93	Traveling grate	251.84	0.00546	2.17E-05	1.84E-04
Boiler 14	1/15/93	Traveling grate	282.98	0.00736	2.60E-05	2.21E-04
Boiler 14	1/15/93	Traveling grate	283.95	0.00185	6.52E-06	5.54E-05
Boiler 14	2/5/93	Traveling grate	210.21	0.00129	6.14E-06	5.22E-05
Boiler 14	2/5/93	Traveling grate	225.95	0.00855	3.78E-05	3.22E-04
Boiler 14	2/5/93	Traveling grate	205.50	0.00110	5.35E-06	4.55E-05
Osceola Farms						
Boiler 2	2/15/93	Inclined grate	207.38	0.00330	1.59E-05	1.35E-04
Boiler 2	2/15/93	Inclined grate	207.38	0.00275	1.33E-05	1.13E-04
Boiler 2	2/15/93	Inclined grate	207.46	<0.00094	<4.53E-06	<3.85E-05
Boiler 2	2/15/93	Inclined grate	207.40	<0.00094	<4.53E-06	<3.85E-05
Boiler 2	2/15/93	Inclined grate	207.28	0.00194	9.36E-06	7.96E-05
Boiler 2	2/15/93	Inclined grate	207.38	<0.00104	<5.01E-06	<4.26E-05
Boiler 4	2/16/93	Horseshoe	207.06	<0.00064	<3.09E-06	<2.63E-05
Boiler 4	2/16/93	Horseshoe	271.34	<0.00072	<2.65E-06	<2.26E-05
Boiler 4	2/16/93	Horseshoe	269.34	<0.00105	<3.90E-06	<3.31E-05
Boiler 4	2/16/93	Horseshoe	255.74	0.00131	5.12E-06	4.35E-05
Boiler 4	2/16/93	Horseshoe	277.16	<0.00105	<3.79E-06	<3.22E-05
Boiler 4	2/16/93	Horseshoe	209.44	<0.00099	<4.73E-06	<4.02E-05
		No. of tests =		27	27	27
		Average (1) =		0.00217	8.98E-06	7.63E-05
		Average (2) =		0.00193	7.95E-06	6.76E-05
		Average (3) =		0.00169	6.93E-06	5.89E-05

* Based on bagasse heating value of 4,250 Btu/lb.

(1) Minimum detectable limit (MDL) used for values reported as below the MDL.
(2) One-half the minimum detectable limit (MDL) used for values reported as below the MDL.
(3) Zero was used for values reported as below the minimum detectable limit.

APPENDIX D

IWAQM PHASE II SUMMARY REPORT

		Sorted by Calpuff.lst order			9937584Y/F1/WP/appc	
Calpuff.lst						10/20/99
Input Group						Modeled
Number	Description	Variable	Seq	Description	Default Value	Value
1	Run Control	METRUN	1	Do we run all periods (1) or a subset (0)?	0	0
1		IBYR	2	Beginning year	User Defined	VAR
1		IBMO	3	Beginning month	User Defined	1
1		IBDY	4	Beginning day	User Defined	1
1		IBHR	5	Beginning hour	User Defined	1
1		IRLG	5	Length of run (hours)	User Defined	VAR
1		NSPEC	6	Number of species modeled (for MESOPUFF II chemistry)	6	6
1		NSE	7	Number of species emitted	3	3
1		ITEST	8		2	2
1		MRESTART	9	Restart options (0 = no restart) allows splitting runs into smaller segments	0	0
1		NRESPD	10		0	0
1		METFM	11	Format of input meteorology (1 = CALMET, 2 = ISC)	1	2
1		AVET	12	Averaging time lateral dispersion parameters (minutes)	60	60
2	Tech Options	MGAUSS	1	Near-field vertical distribution (1 = Gaussian)	1	1
2		MCTADJ	2	Terrain adjustments to plume path (3 = Plume path)	3	3
2		MCTSG	3	Do we have subgrid hills? (0 = No) allows CTDM-like treatment for subgrid scale hills	0	0
2		MSLUG	4	Near-field puff treatment (0 = No slugs)	0	0
2		MTRANS	5	Model transitional plume rise? (1 = Yes)	1	1
2		MTIP	6	Treat stack tip downwash? (1 = Yes)	1	1
2		MSHEAR	7	Treat vertical wind shear? (0 = No)	0	0
2		MSPLIT	8	Allow puffs to split? (0 = No)	0	0
2		MCHEM	9	MESOPUFF-II Chemistry? (1 = Yes)	1	1
2		MWET	10	Model wet deposition? (1 = Yes)	1	1
2		MDRY	11	Model dry deposition? (1 = Yes)	1	1
2		MDISP	12	Method for dispersion coefficients (3 = PG & MP)	3	3
2		MTURBVW	13	Turbulence characterization? (Only if MDISP = 1 or 5)	3	NA
2		MDISP2	14	Backup coefficients (Only if MDISP = 1 or 5)	3	NA
2		MROUGH	15	Adjust PG for surface roughness? (0 = No)	0	0
2		MPARTL	16	Model partial plume penetration? (0 = No)	1	1
2		MTINV	17	Elevated inversion strength (0 = compute from data)	0	0
2		MPDF	18	Use PDF for convective dispersion? (0 = No)	0	0
2		MSGTIBL	19	Use TIBL module? (0 = No) allows treatment of subgrid scale coastal areas	0	0
2		MREG	20	Regulatory default checks? (1 = Yes)	1	0
3	Species List	CSPECn		Names of species modeled (for MESOPUFF II must be SO2-SO4-NOX-HNO3-NO3)	User Defined	ALL 6
3		Specie Groups		Grouping of species if any	User Defined	NA
3		Specie Names		Manner species will be modeled	User Defined	DEPOS.
4	Grid Control	NX	1	Number of east-west grids of input meteorology	User Defined	2
4		NY	2	Number of north-south grids of input meteorology	User Defined	2
4		NZ	3	Number of vertical layers of input meteorology	User Defined	1
4		DGRIDKM	4	Meteorology grid spacing (km)	User Defined	172
4		ZFACE	5	Vertical cell face heights of input meteorology	User Defined	0;5000
4		XORIGKM	6	Southwest corner (east-west) of input User	Defined meteorology	-172
4		YORIGIM	7	Southwest corner (north-south) of input User	Defined meteorology	-172
4		IUTMZN	8	UTM zone	User Defined	0

		Sorted by Calpuff.lst order			9937584Y/F1/WP/appd
Calpuff.lst					10/20/99
Input Group					Modeled
Number	Description	Variable	Seq	Description	Default Value	Value
4		XLAT	9	Latitude of center of meteorology domain	User Defined	26.6
4		XLONG	10	Longitude of center of meteorology domain	User Defined	80.5
4		XTZ	11	Base time zone of input meteorology	User Defined	5
4		IBCOMP	12	Southwest X-index of computational domain	User Defined	1
4		JBCOMP	13	Southwest Y-index of computational domain	User Defined	1
4		IECOMP	14	Northeast X-index of computational domain	User Defined	2
4		JECOMP	15	Northeast Y-index of computational domain	User Defined	2
4		LSAMP	16	Use gridded receptors? (T = Yes)	F	F
4		IBSAMP	17	Southwest X-index of receptor grid	User Defined	0
4		JBSAMP	18	Southwest Y-index of receptor grid	User Defined	0
4		IESAMP	19	Northeast X-index of receptor grid	User Defined	0
4		JESAMP	20	Northeast Y-index of receptor grid	User Defined	0
4		MESHDN	21	Gridded recpetor spacing = DGRIDKM/MESHDN	1	1
5	Output Options	ICON	1	Output concentrations? (1 = Yes)	1	1
5		IDRY	2	Output dry deposition flux? (1 = Yes)	1	0
5		IWET	3	Output west deposition flux? (1 = Yes)	1	0
5		IVIS	4	Output RH for visibility calculations (1 = Yes)	1	0
5		LCOMPRS	5	Use compression option in output? (T = Yes)	T	T
5		ICPRT	6	Print concentrations? (0 = No)	0	0
5		IDPRT	7	Print dry deposition fluxes (0 = No)	0	0
5		IWPRT	8	Print wet deposition fluxes (0 = No)	0	0
5		ICFRQ	9	Concentration print interval (1 = hourly)	1	24
5		IDFRQ	10	Dry deposition flux print interval (1 = hourly)	1	1
5		IWFRQ	11	West deposition flux print interval (1 = hourly)	1	1
5		IPRTU	12	Print output units (1 = g/m**3; g/m**2/s; 3 = ug/m3, ug/m2/s)	1	3
5		IMESG	13	Status messages to screen? (1 = Yes)	1	1
5		LDEBUG	14	Turn on debug tracking? (F = No)	F	F
5		NPFDEB	15	(Number of puffs to track)	(1)	1
5		NN1	16	(Met. Period to start output)	(1)	1
5		NN2	17	(Met. Period to end output)	(10)	10
7	Dry Dep Chem	Dry Gas Dep		Chemical parameters of gaseous deposition species	User Defined	DEFAULT
8	Dry Dep Size	Dry Part. Dep		Chemical parameters of particulate deposition species	User Defined	DEFAULT
9	Dry Dep Misc	RCUTR	1	Reference cuticle resistance (s/cm)	30	30
9		RGR	2	Reference ground resistance (s/cm)	10	10
9		REACTR	3	Reference reactivity	8	8
9		NINT	4	Number of particle-size intervals	9	9
9		IVEG	5	Vegetative state (1 = active and unstressed)	1	1
10	Wet Dep	Wet Dep		Wet deposition parameters	User Defined	
11	Chemistry	MOZ	1	Ozone background? (0 = constant background value; 1 = read from ozone.dat)	1	1
11		BCKO3	2	Ozone default (ppb) (Use only for missing data)	80	80
11		BCKNH3	3	Ammonia background (ppb)	10	10

Calpuff.lst Input Group Number	Description	Variable	Seq	Description	Default Value	10/20/99 Modeled Value
11		RNITE1	4	Nighttime SO2 loss rate (%/hr)	0.2	0.2
11		RNITE2	5	Nighttime NOx loss rate (%/hr)	2	2
11		RNITE3	6	Nighttime HNO3 loss rate (%/hr)	2	2
12	Dispersion	SYTDEP	1	Horizontal size (m) to switch to time dependence	550	550
12		MHFTSZ	2	Use Heffter for vertical dispersion? (0 = No)	0	0
12		JSUP	3	PG Stability class above mixed layer	5	5
12		CONK1	4	Stable dispersion constant (Eq 2.7-3)	0.01	0.01
12		CONK2	5	Neutral dispersion constant (Eq 2.7-4)	0.1	0.1
12		TBD	6	Transition for downwash algorithms (0.5 = ISC)	0.5	0.5
12		IURB1	7	Beginning urban landuse type	10	10
12		IURB2	8	Ending urban landuse type	19	19
12		ILANDUIN	9	Land use type (20 = Unirrigated agricultural land)	(20)	20
12		ZOIN	10	Roughness length (m)	(0.25)	0.25
12		XLAIIN	11	Leaf area index	(3)	3
12		ELEVIN	12	Met. Station elevation (m above MSL)	(0)	0
12		XLATIN	13	Met. Station North latitude (degrees)	(-999)	-999
12		XLONIN	14	Met. Station West longitude (degrees)	(-999)	-999
12		ANEMHT	15	Anemometer height of ISC meteorological data (m)	(10)	10.1
12		ISIGMAV	16	Lateral turbulence (Not used with ISC meteorology)	(1)	NA
12		IMIXCTDM	17	Mixing heights (Not used with ISC meteorology)	(1)	NA
12		XMXLEN	18	Maximum slug length in units of DGRIDKM	1	1
12		XSAMLEN	19	Maximum puff travel distance per sampling step (units of DGRIDKM)	1	1
12		MXNEW	20	Maximum number of puffs per hour	99	99
12		MXSAM	21	Maximum sampling steps per hour	99	99
12		NCOUNT	22	Iterations when computing Transport Wind (Calmet & Profile Winds)	(2)	2
12		SYMIN	23	Minimum lateral dispersion of new puff (m)	1	1
12		SZMIN	24	Minimum vertical dispersion of new puff (m)	1	1
12		SVMIN	25	Array of minimum lateral turbulence (m/s)	6 * 0.50	6*0.50
12		SWMIN	26	Array of minimum vertical turbulence (m/s)	0.20,0.12,0.08,0.06,0.03,0.016	SAME
12		CDIV (1), (2)	27	Divergence criterion for dw/dz (1/s)	0.01 (0.0,0.0)	0.0,0.0
12		WSCALM	28	Minimum non-calm wind speed (m/s)	0.5	0.5
12		XMAXZI	29	Maximum mixing height (m)	3000	3000
12		XMINZI	30	Minimum mixing height (m)	50	50
12		WSCAT	31	Upper bounds 1st 5 wind speed classes (m/s)	1.54,3.09,5.14,8. 23,10.8	SAME
12		PLX0	32	Wind speed power-law exponents	0.07,0.07,0.10,0.15,0.35,0.55	SAME
12		PTGO	33	Potential temperature gradients PG E and F (deg/km)	0.020,0.035	SAME
12		PPC	34	Plume path coefficients (only if MCTADJ = 3)	0.5,0.5,0.5,0.5,0.35,0.35	SAME
12		SL2PF	35	Maximum Sy/puff length	10	10
12		NSPLIT	36	Number of puffs when puffs split	3	3
12		IRESPLIT	37	Hours when puff are eligible to split	User Defined	HR 17=1
12		ZISPLIT	38	Previous hour's mixing height(minimum)(m)	100	100
12		ROLDMAX	39	Previous Max mix ht/current mix ht ratio must be less then this value for puff to split	0.25	0.25
12		EPSSLUG	40	Convergence criterion for slug sampling integration	1.00E-04	1.0E-04
12		EPSAREA	41	Convergence criterion for area source integration	1.00E-06	1.0E-06
13	Point Source	NPT1	1	Number of point sources	User Defined	2

Table D-1. IWAQM Phase II Calpuff Default Options - Atlantic Sugar Assoc Regional Haze (Lite) Analysis

		Sorted by Calpuff.lst order			9937584Y/F1/WP/appd
Calpuff.lst					10/20/99
Input Group					Modeled
Number	Description	Variable	Seq	Description	Default Value	Value
13		IPTU	2	Units of emission rates (1 = g/s)	1	1
13		NSPT1	3	Number of point source-species combinations	0	0
13		NPT2	4	Number of point sources with fully variable emission rates	0	0
13		Point Sources		Point sources characteristics	User Defined	VAR
14	Area Source	Area Sources		Area sources characteristics	User Defined	NA
15	Volume Source	Volume		Volume sources characteristics	User Defined Sources	NA
16	Line Source	Line Sources		Buoyant lines source characteristics	User Defined	NA
17	Receptors	NREC		Number of user defined receptors	User Defined	180
17		Receptor Data		Location and elevation (MSL) of receptors	User Defined	VAR

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

Atlantic Sugar Association, Inc.

POST OFFICE BOX 1570
BELLE GLADE, FLORIDA 33430

TELEPHONE (561) 996-6541
TELEFAX (561) 996-8021

October 22, 1999

RECEIVED
OCT 26 1999
BUREAU OF AIR REGULATION

Mr. Al Linero, P.E.
Professional Engineering Administrator
Florida Department of Environmental Protection
Division of Air Resources Management
2600 Blair Stone Road, MS # 5505
Tallahassee, FL 32399-2400

Re: Application for Air Permit - Title V Source

Dear Sir:

0990016-004-AC
PSD-FL-279

Enclosed are seven sets of the application for Air Permit - Title V Source related to Atlantic Sugar Association, Inc.'s Boiler no. 5.

A check for $7,500.00 is also enclosed to cover the application fee.

Thank you for your attention and if you have any questions, please let me know.

Sincerely,

Hector J. Cardentey
Environmental Director

HJC/lm

Enclosures

CC: EPA
NPS
palm Bch Co
SD
J. Koerner, BAR
C. Carlson, BAR

ATLANTIC SUGAR ASSOCIATION, INC. 069067

DATE	NUMBER	DESCRIPTION	PURCHASES	DISCOUNT	BALANCE	ACCOUNT NO.
10/15/99		Application fee for new PSD Permit for Boiler #5			$ 7,500.00	8505787

PLEASE DETACH CHECK BEFORE DEPOSITING

FIRST UNION NATIONAL BANK
OF FLORIDA
BELLE GLADE, FLORIDA 33430

63-643
670

069067

Atlantic Sugar Association, Inc.
P.O. BOX 1570, BELLE GLADE, FLORIDA 33430

CHECK DATE	CHECK NO.
10/15/99	69067

CHECK AMOUNT
$7,500.00 ******

PAY TO THE ORDER OF

FLORIDA DEPT. OF ENVIROMENTAL PROTECTION

ATLANTIC SUGAR ASSOCIATION, INC.

⑈069067⑈ ⑆067006432⑆ 26760000 15100⑈