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BUREAU OF AIR REGULATION

APPLICATION FOR
AIR CONSTRUCTION PERMIT
BOILER NO. 7
WOOD CHIP TEST BURN

UNITED STATES SUGAR CORPORATION
CLEWISTON, FLORIDA

Prepared For:
United States Sugar Corporation
111 Ponce de Leon Avenue
Clewiston, Florida 33440

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

May 2007

0637637

DISTRIBUTION:
4 Copies – FDEP
2 Copies – U.S. Sugar
1 Copy – Golder Associates Inc.

AIR CONSTRUCTION PERMIT APPLICATION-LONG FORM

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also use this form to apply for an air construction permit:

- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- Where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- Where the applicant proposes to establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

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

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **United States Sugar Corporation**	
2. Site Name: **U.S. Sugar Clewiston Mill**	
3. Facility Identification Number: **0510003**	
4. Facility Location...: Street Address or Other Locator: **W.C. Owens Ave. and S.R. 832** City: **Clewiston** County: **Hendry** Zip Code: **33440**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Neil Smith, Vice President & General Manager, Sugar Manufacturing**
2. Application Contact Mailing Address... Organization/Firm: **United States Sugar Corporation** Street Address: **111 Ponce De Leon Ave.** City: **Clewiston** State: **FL** Zip Code: **33440**
3. Application Contact Telephone Numbers... Telephone: **(863) 902-2703** ext. Fax: **(863) 902-2729**
4. Application Contact Email Address: **nsmith@ussugar.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3. PSD Number (if applicable):
2. Project Number(s):	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.
☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).
☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

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

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

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

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

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

Application Comment

Air construction permit application to fire Boiler No. 7 with up to 25 percent of the total heat input coming from wood chips.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
014	Boiler No. 7	AC1A	$7,500

Application Processing Fee

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

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name : **Neil Smith, Vice President & General Manager, Sugar Manufacturing**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **United States Sugar Corporation** Street Address: **111 Ponce De Leon Ave.** City: **Clewiston** State: **FL** Zip Code: **33440**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(863) 902-2703** ext. Fax: **(863) 902-2729**
4.	Owner/Authorized Representative Email Address: **nsmith@ussugar.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* Signature Date

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name : **Neil Smith, Vice President & General Manager, Sugar Manufacturing**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **United States Sugar Corporation** Street Address: **111 Ponce De Leon Ave.** City: **Clewiston** State: **FL** Zip Code: **33440**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(863) 902-2703** ext. Fax: **(863) 902-2729**
4.	Owner/Authorized Representative Email Address: **nsmith@ussugar.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* Signature 5/16/07 Date

APPLICATION INFORMATION

Application Responsible Official Certification

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

1.	Application Responsible Official Name:
2.	Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source.
3.	Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4.	Application Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
5.	Application Responsible Official Email Address:
6.	Application Responsible Official Certification: *I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.* Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

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

5. Professional Engineer Statement:

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

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

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

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

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

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

David A. Buff 5/22/07

Signature Date

(seal)

* Attach any exception to certification statement.

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

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) 506.1 North (km) 2956.9		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) 26 / 44 / 06 Longitude (DD/MM/SS) 80 / 56 / 19	
3. Governmental Facility Code: 0	4. Facility Status Code: A	5. Facility Major Group SIC Code: 20	6. Facility SIC(s): 2061 2062
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: Neil Smith, Vice President & General Manager, Sugar Manufacturing
2. Facility Contact Mailing Address... Organization/Firm: United States Sugar Corporation Street Address: 111 Ponce De Leon Ave. City: Clewiston State: FL Zip Code: 33440
3. Facility Contact Telephone Numbers: Telephone: (863) 902-2703 ext. Fax: (863) 902-2729
4. Facility Contact Email Address: nsmith@ussugar.com

Facility Primary Responsible Official

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

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

FACILITY INFORMATION

Facility Regulatory Classifications

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

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

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Ammonia – NH_3	B	No
Carbon Monoxide – CO	A	No
Nitrogen Oxides - NO_X	A	No
Particulate Matter Total – PM	A	No
Particulate Matter – PM_{10}	A	No
Sulfur Dioxide – SO_2	A	No
Sulfuric Acid Mist – SAM	A	No
Volatile Organic Compounds – VOC	A	No
Total Hazardous Air Pollutants – HAPs	A	No
Acetaldehyde – H001	A	No
Chlorine – H038	A	No
p-Cresol – H052	A	No
Dibenzofuran – H058	A	No
Formaldehyde – H095	A	No
Hydrochloric Acid – H106	A	No
Benzene – H107	A	No
Manganese Compounds – H113	A	No
Mercury – H114	B	No
Naphthalene – H132	A	No
Phenol – H144	A	No
Polycyclic Organic Matter – H151	A	No
Styrene – H163	A	No
Toluene – H169	A	No

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

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

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

Additional Requirements for FESOP Applications

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

Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:

   Boiler No. 7

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

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

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

    Spreader-stoker vibrating-gate boiler fired by carbonaceous fuel, wood chips, and distillate fuel oil (Grades No. 1 and 2) with a maximum sulfur content of 0.05 percent by weight. Fuel oil can include facility-generated, on-specification used oil.

Emissions Unit Control Equipment

1.	Control Equipment/Method(s) Description: **Electrostatic Precipitator** **Wet Sand Separator**
2.	Control Device or Method Code(s): **010, 099**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate: 385,000 lb/hr steam		
3. Maximum Heat Input Rate: 812 million Btu/hr		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment: Maximum heat input rate based on 1-hour maximum steam rate of 385,000 lb/hr for carbonaceous fuel firing. The maximum permitted 24-hour average heat input rate for firing carbonaceous fuel is 738 MMBtu/hr (Permit No. 0510003-017-AV), and the maximum permitted 1-hour average heat input rate for firing No. 2 fuel oil is 326 MMBtu/hr, corresponding to a maximum steam production rate of 225,000 lb/hr (Permit No. 0510003-018-AC).		

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **BLR-7**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **225** feet	7. Exit Diameter: **8.0** feet
8. Exit Temperature: **272**°F	9. Actual Volumetric Flow Rate: **341,000** 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 Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters based on average 2006 and 2007 stack testing. Stack flow rate representative of heat input rate of 738 MMBtu/hr. Stack diameter reflects replacement of upper portion of Boiler No. 7 stack with stack from Boiler No. 3.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Bagasse; All Boiler Sizes**		
2. Source Classification Code (SCC): **1-02-011-01**	3. SCC Units: **Tons Bagasse Burned**	
4. Maximum Hourly Rate: **112.8**	5. Maximum Annual Rate: **897,900**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.24 (dry)**	8. Maximum % Ash: **8.4 (dry)**	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment: **Maximum hourly rate based on a heat input rate of 812 MMBtu/hr (1-hour average) and annual rate based on a rate of 738 MMBtu/hr (24-hour average). Both annual and hourly maximums were based on a heating value of 3,600 Btu/lb wet bagasse (Permit No. 0510003-010-AC/PSD-FL-272A and Permit No. 0510003-017-AV).**		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Distillate Oil; Grades 1 and 2**		
2. Source Classification Code (SCC): **1-02-005-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **2.417**	5. Maximum Annual Rate: **4,500**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
10. Segment Comment: **Maximum hourly and annual rates, and the maximum sulfur content of the distillate fuel oil, based on current permit limits (Permit No. 0510003-018-AC). Includes combustion of facility-generated, on-specification used oil (Permit No. 0510003-024-AC).**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Wood/Bark Waste (> 50,000 lb/hr steam)**		
2. Source Classification Code (SCC): **1-02-009-02**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **90.2**	5. Maximum Annual Rate: **179,580**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.07**	8. Maximum % Ash: **6**	9. Million Btu per SCC Unit: **9.0**
10. Segment Comment: **Maximum hourly rate based on 100 percent woodchips (heating value 4,500 Btu/lb) and 812 MMBtu/hr (1-hour max) heat input rate. Maximum annual usage based on 179,580 TPY woodchips, which represents 25 percent of the potential heat input capacity of the boiler.**		

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type):		
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:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	099	010	EL
PM_{10}	099	010	EL
SO_2			EL
NO_X			EL
CO			EL
VOC			EL
SAM			NS
H017 (Benzene)			NS
H038 (Chlorine)			NS
H095 (Formaldehyde)			NS
H106 (Hydrogen Chloride)	010		NS
HAPs			NS

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: NO_X	2. Total Percent Efficiency of Control:
3. Potential Emissions: 252.5 lb/hour 857.4 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 0.311 lb/MMBtu for wood chip firing Reference: Based on stack testing using a 25 percent wood/ 75 percent bagasse by heat input mix	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Maximum Hourly Rate:
812 MMBtu/hr x 0.311 lb/MMBtu = 252.5 lb/hr

Maximum Annual Rate:
Wood chip firing:
738 MMBtu/hr x 8,760 hr/yr x 25% from wood chips firing = 1,616,220 MMBtu/yr
1,616,220 MMBtu/yr x 0.311 lb/MMBtu x 1 ton/2,000 lb = 251.3 TPY
Remainder due to bagasse firing:
738 MMBtu/hr x 8,760 hr/yr x 75% from wood chips firing = 4,848,660 MMBtu/yr
4,848,660 MMBtu/yr x 0.25 lb/MMBtu x 1 ton/2,000 lb = 606.1 TPY
Total Annual:
251.3 TPY + 606.1 TPY = 857.4 TPY

11. Potential Fugitive and Actual Emissions Comment:

Emission limit for bagasse only firing is 0.25 lb/MMBtu.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.311 lb/MMBtu**	4. Equivalent Allowable Emissions: **252.5** lb/hour **251.3** tons/year
5. Method of Compliance: **EPA Method 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Applies to wood chip burning.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.25 lb/MMBtu**	4. Equivalent Allowable Emissions: **203.0** lb/hour **606.1** tons/year
5. Method of Compliance: **EPA Method 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on bagasse firing limits in Permit No. 0510003-017-AV.**	

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Rule 62-212.400(5), F.A.C., and Permit No. 0510003-017-AV.**	

Visible Emissions Limitation: Visible Emissions Limitation _ of

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 4

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **ABB-Kent Taylor or equivalent** Model Number: **621D**	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Fuel oil flow measurement instrument. Permit No. 0510003-017-AV.**	

Continuous Monitoring System: Continuous Monitor 2 of 4

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **ABB-Kent Taylor or equivalent** Model Number: **621D**	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Steam production measurement instrument. Permit No. 0510003-017-AV.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 3 of 4

1. Parameter Code: **Steam Pressure Monitor**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **ABB-Kent Taylor or equivalent** Model Number: **621G** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Steam pressure measurement instrument. Permit No. 0510003-017-AV.**	

Continuous Monitoring System: Continuous Monitor 4 of 4

1. Parameter Code: **TEMP**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **ABB-Kent Taylor or equivalent** Model Number: **600T** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Steam temperature measurement instrument. Permit No. 0510003-017-AV.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☒ Previously Submitted, Date **5/2005 - TV Renewal**
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **USSC-EU1-I2** ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☒ Previously Submitted, Date **5/2005 - TV Renewal**
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable
6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   ☒ Attached, Document ID: **See PSD Report** ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☒ Attached, Document ID: **See PSD Report** ☐ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☒ Attached, Document ID: **See PSD Report** ☐ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: _____ ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

USSC-EU1-I2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT USSC-EU1-I2
BOILER NO. 7 FUEL ANALYSIS

Parameter	Units	Wood Chips	Bagasse[b]	Parameter	Units	No. 2 Fuel Oil
As Received				Density	lb/gal	6.83
Moisture	%	30 - 50	51.63	Moisture	%	0.51 [c]
Ash	%	3.26 [a]		AHV	Btu/lb	19,910
HHV	Btu/lb	4,500 - 5,435		AHV	Btu/gal	135,000
Arsenic	ppm	0.10 [a]		Carbon	%	84.7
Nitrogen	%	0.20 [a]		Hydrogen	%	15.3
				Nitrogen	%	0.015 [d]
Dry Basis				Oxygen	%	0.38
Ash	%	4.93	4.53	Sulfur	%	0.05 [d]
HHV	Btu/lb	9,000 - 10,870	7,920	Ash/Inorganic	%	0.06 [c]
Arsenic	ppm	0.15	0.39			
Nitrogen	%	0.31	0.35			
Chromium	ppm	5	0.4			
Copper	ppm	24.4				

Btu/lb = British thermal unit per pound
HHV = higher heating value
AHV = approximate heating value

Notes:
[a] Wood Chip Analysis Results - September 16, 2005
[b] Proximate, Ultimate, and Heat Content Analyses Results for Bagasse for U.S. Sugar, Clewiston
[c] Source: Perry's Chemical Engineering Handbook. Sixth Edition, 1984.
Represents average fuel characteristics.
[d] Permit limits, Permit No. 0510003-017-AV

PSD REPORT

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LIST OF ACRONYMS AND ABBREVIATIONS

AAQS	Ambient Air Quality Standards
AOR	annual operating report
APH	air preheater
BACT	Best Available Control Technology
Btu/gal	British thermal units per gallon
Btu/lb	British thermal units per pound
CAA	Clean Air Act
CFR	Code of Federal Regulations
CO	carbon monoxide
DNCG	dilute non-condensable gas
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
F	fluoride
°F	degrees Fahrenheit
ft/s	feet per second
F.A.C.	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
FGR	flue gas recirculation
FR	fuel reburning
gal/hr	gallons per hour
gal/yr	gallons per year
GEP	Good Engineering Practice
H_2O	water
HAP	hazardous air pollutant
HCl	hydrogen chloride
Hg	mercury
HSH	highest, second-highest
km	kilometer
LAER	lowest achievable emission rate
lbs/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units

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LIST OF ACRONYMS AND ABBREVIATIONS (cont'd)

LEA	less excess air
LNB	low-NO_x burner
LVHC	low volume high concentration
m	meter
MACT	Maximum Achievable Control Technology
MMBtu/hr	million British thermal units per hour
MMBtu/yr	million British thermal units per year
$MMft^3$	million cubic feet
MMscf/yr	million standard cubic feet per year
N_2	nitrogen
NAAQS	National Ambient Air Quality Standards
NCG	non-condensable gas
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
NSR	new source review
NWA	National Wilderness Area
O_2	oxygen
OAQPS	Office of Air Quality Planning and Standards
OFA	overfire air
PCP	pollution control project
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter equal to or less than 10 micrometers
ppmv	parts per million by volume
PSD	prevention of significant deterioration
RBLC	RACT, BACT, LAER Clearinghouse
SAM	sulfuric acid mist
scf/hr	standard cubic foot per hour
SCR	selective catalytic reduction
SIL	significant impact level

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LIST OF ACRONYMS AND ABBREVIATIONS (cont'd)

SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SOG	stripper off gas
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SR	State Road
TPD	tons per day
TPH	tons per hour
TPY	tons per year
TRS	total reduced sulfur
TSM	total selected metals
USSC	United States Sugar Corporation
μm	micrometer
$\mu g/m^3$	micrograms per cubic meter
VOC	volatile organic compound

1.0 INTRODUCTION

United States Sugar Corporation (U.S. Sugar) owns and operates a sugar mill and sugar refinery located in Clewiston, Hendry County, Florida. U.S. Sugar is proposing to add wood chips as an allowable fuel for Boiler No. 7 (EU 014). Boiler No. 7 currently fires bagasse as its primary fuel, with ultra-low sulfur No. 2 fuel oil used for startup, shutdown, and as a supplementary fuel. U.S. Sugar is currently operating under Title V Permit No. 0510003-017-AV, most recently issued on October 18, 2004.

U.S. Sugar currently operates Boiler No. 7, which burns bagasse and No. 2 fuel oil, to generate steam for sugarcane processing and raw sugar refining operations. Boiler No. 7 is designed and permitted to produce 385,000 pounds per hour (lb/hr) of steam as a 1-hour average, and 350,000 lb/hr of steam as a daily 24-hour average. The boiler is permitted to operate up to 365 days per calendar year [8,760 hours per year (hr/yr)].

The use of wood chips as a secondary fuel will allow the facility to continue operations when bagasse is not available, without needing to use No. 2 fuel oil. Currently the supply of bagasse is limited due to the sugarcane crop, and a supplemental fuel must be used when bagasse is not available, or when the existing bagasse supply is exhausted. Therefore, U.S. Sugar desires the ability to burn limited amounts of wood fuel in Boiler No. 7, i.e., up to 179,580 tons per year (TPY), which represents 25 percent of the boiler's potential annual heat input rate.

The project represents a renewable energy project, which is an effort to reduce fossil fuel combustion and replace it with renewable biomass combustion.

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

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 Hendry 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 (40 CFR 52.21), and are implemented in Florida through delegation to the FDEP. FDEP has adopted the EPA PSD regulations as Rule 62-212.400, Florida Administrative Code (F.A.C.).

The PSD applicability for the project is summarized in Table 1-1. Based on the net emissions increase due to the proposed project, PSD review is required for nitrogen oxides (NO_x). Hendry County has been designated as an attainment or unclassifiable area for all criteria pollutants. The county is also classified as a PSD Class II area for nitrogen dioxide (NO_2); therefore, the new source review will follow PSD regulations pertaining to such designations.

Because NO_x is subject to PSD review, the following analyses are required:

1. Ambient monitoring analysis, unless the net increase in emissions due to the modification causes impacts below specified significant impact levels;
2. Application of BACT for each new or modified emissions unit, for each pollutant subject to PSD review;
3. Air quality impact analysis, unless the net increase in emissions due to the modification causes impacts below specified significant impact levels; and
4. Additional impact analysis (e.g., impact on soils, vegetation, visibility), including impacts on PSD Class I areas.

This PSD permit application addresses these requirements and is organized into six additional sections. A description of the project, including air emissions and pollution control equipment, is presented in Section 2.0. The regulatory applicability analysis for the proposed project is presented in Section 3.0. The required ambient air monitoring analysis is presented in Section 4.0 and the BACT analysis is presented in Section 5.0. The air quality impact analysis is presented in Section 6.0 and the additional impact analysis is presented in Section 7.0.

2.0 PROJECT DESCRIPTION

U.S. Sugar owns and operates a raw sugar mill and sugar refinery located in Clewiston, Hendry County, Florida. U.S. Sugar is proposing to add the capability to burn wood chips in Boiler No. 7 at the mill to provide a way to operate the boiler when bagasse is not available, without needing to fire a large amount of fuel oil. The project represents a renewable energy project, which is an effort to reduce fossil fuel combustion and replace it with renewable biomass combustion.

The Clewiston sugar mill receives sugarcane by train from nearby cane fields and processes it into raw sugar. The cane is first cut into small pieces, and is then passed through a series of presses (mills) where the sugar cane juices are squeezed from the cane. The mills are steam or hydraulically driven. The fibrous coproduct material remaining 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. U.S. Sugar began operating an onsite sugar refinery in 1997, wherein raw sugar is refined into white sugar suitable for human consumption. Steam is also used in the raw sugar refining process. Both raw and refined sugar is shipped offsite to customers.

The primary fuel for the boilers in the Clewiston mill is bagasse, while No. 2 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.

The Clewiston mill is currently operated under Title V Operation Permit No. 0510003-017-AV, issued October 18, 2004.

2.1 Existing Operations

U.S. Sugar currently operates Boiler No. 7 to provide steam for sugarcane processing and raw sugar refining operations. The boiler is of Alpha Conal design, Model No. ATT-203-18, with a design steam rating of 385,000 lbs/hr as a 1-hour average. Boiler No. 7 is currently permitted to burn the following fuels:

- Carbonaceous (bagasse) fuel and

- No. 2 fuel oil, with a sulfur content not to exceed 0.05 percent by weight, including facility-generated on-specification used oil.

Boiler No. 7 currently is permitted to operate up to a maximum heat input rate of 812 million British thermal units per hour (MMBtu/hr) as a 1-hour average, and 738 MMBtu/hr as a 24-hour average, for bagasse burning. Based on a nominal heat content of 3,600 British thermal units per pound (Btu/lb), this heat input rate is equivalent to a maximum bagasse burning rate of 112.8 tons per hour (TPH), as a 24-hour average.

The maximum heat input for the boiler when firing No. 2 fuel oil is 326 MMBtu/hr. Based on a heating value for No. 2 fuel oil of 135,000 British thermal units per gallon (Btu/gal), this heat input rate is equivalent to 2,417 gallons per hour (gal/hr) of fuel oil, which corresponds to a maximum steam production rate of 225,000 lb/hr.

Boiler No. 7 has an electrostatic precipitator (ESP) control device for particulate matter (PM) control. Currently there is no limitation on Boiler No. 7 on annual operating hours. Boiler No. 7, which was constructed primarily to support the new sugar refinery, began operating in 1997.

This emissions unit is regulated under Rule 62-296.410, F.A.C., Carbonaceous Fuel Burning Equipment. This emissions unit is also subject to the requirements of 40 CFR 63, Subpart DDDDD [National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial and Institutional Boilers and Process Heaters]. However, the unit is not required to be in full compliance with this subpart until September 13, 2007.

2.2 Proposed Modifications

U.S. Sugar is proposing modifications to Boiler No. 7 to allow the boiler to burn wood chips. No physical changes to the boiler are required to accommodate wood chip firing. However, this change could be categorized as a change in the method of operation, since wood fuel is not currently permitted to be burned in the boiler. This change will allow the boiler to continue operations when bagasse is not available, without having to burn No. 2 fuel oil. Wood chips would typically be burned in the off-season, when bagasse from the mill is not available. However, it could also be burned for limited time periods during the crop season; for example, during a mill startup. It is noted that, with the current conveying system, bagasse from the mills and wood chips can not be burned in Boiler No. 7 at the same time.

The current permitted maximum hourly bagasse heat input rate is 812 MMBtu/hr (Permit No. 0510003-017-AV). The maximum 24-hour average heat input is 738 MMBtu/hr. U.S. Sugar is proposing to limit the potential amount of wood chips firing to 179,580 TPY or 1,618,650 MMBtu/yr (based on 4,500 Btu/lb heating value), which represents 25 percent of the potential heat input to the boiler.

The goal of wood chip firing is to reduce fuel oil firing. Historically, U.S. Sugar has fired up to 3,653,640 gal/yr (493,241 MMBtu/yr) of No. 2 fuel oil in Boiler No. 7. Wood chip firing would primarily occur during the off-season..

The maximum hourly heat input rate when firing No. 2 fuel oil will not be affected by the proposed project. However, the project will result in an actual reduction in annual fuel oil usage in the boiler, since the preferred alternative fuel will become wood chips. U.S. Sugar will maintain the fuel oil sulfur content at a maximum of 0.05 percent.

2.3 Air Emission Estimates and Pollution Control Equipment

Emissions of PM and particulate matter equal to or less than 10 microns in diameter (PM_{10}) from Boiler No. 7 are currently controlled by a wet sand separator (cyclone) followed by an ESP. The wet sand separator is designed to remove the large particulate particles prior to the flue gas stream entering the ESP. Good combustion practices (GCP) are implemented for Boiler No. 7 for control of NO_x, carbon monoxide (CO), volatile organic compounds (VOC), and organic hazardous air pollutant (HAP) emissions. A 225-foot tall stack provides for dispersion of air emissions from Boiler No. 7.

2.3.1 Baseline Actual Emissions

The past actual (baseline actual) annual average emissions for Boiler No. 7 are presented in Table 2-1. The basis of the emission estimates are presented in Appendix A. Based on the recently adopted Florida new source review (NSR) reform rules (Rules 62-210 and 212, F.A.C.), the baseline actual emissions are based on a consecutive 24-month period out of the last 10 years. Actual emissions for each of these 10 years (1997-2006) were determined based on operating data, available stack test data, and emission factors. For each pollutant, the consecutive 2-year period with the highest average TPY emissions was selected as the baseline actual emissions for Boiler No. 7. The consecutive 2-year period used for each pollutant are as follows:

- Sulfur Dioxide (SO_2): 1999 to 2000
- Nitrogen Oxides (NO_x): 1999 to 2000
- Carbon Monoxide (CO): 1999 to 2000
- Particulate Matter (PM): 2003 to 2004
- Particulate Matter less than or equal to 10 microns (PM_{10}): 2003 to 2004
- Volatile Organic Compounds (VOCs): 1999 to 2000
- Sulfuric Acid Mist (SAM): 1999 to 2000
- Lead (Pb): 1990 to 2000
- Mercury (Hg): 1999 to 2000

The baseline actual emissions for Boiler No. 7 shown in Table 2-1 may differ from the annual emissions shown in the Annual Operating Reports (AORs) submitted to the FDEP, as described below. The emission factors reported in the AOR for each pollutant are presented in Appendix A, Table A-1. The revised emission factors used for determining the baseline actual emissions are shown in Appendix A, Table A-2. It is noted that the basic operation of the boiler has not changed over the last 10 years.

The resulting baseline actual emissions for each pollutant, based on the revised emission factors, are presented in Appendix A, Table A-3 for each year. The resulting 2-year average emissions for each 2-year period during the last 10 years are presented in Appendix A, Table A-4. The highest 2-year average for each pollutant represents the baseline actual emissions, which are shown in Table 2-1.

Sulfur Dioxide

The SO_2 emission factor used in the past AOR reporting was based on the sulfur content of the No. 2 fuel oil used along with AP-42 factors (range of 4.26 to 7.85 pounds per thousand gallons [lb/10^3 gallons] using a factor of 157*S, where S = sulfur content). SO_2 emissions from the boiler when burning bagasse were based on special stack tests conducted in 1997 and 2005.

To determine the baseline actual emissions from fuel oil combustion, the current AP-42 factor for distillate oil of 142*S lb/10^3 gallons (where S= sulfur content), along with the annual fuel usage from AOR data, was used.

To estimate baseline actual SO_2 emissions from bagasse firing from the boiler when burning bagasse, the special stack tests conducted in 1997 and 2005, shown in Appendix A, Table A-5, were used.

These are the only stack tests available for the boiler for SO_2. The SO_2 emissions were 0.101 and 0.468 pound per ton (lb/ton) bagasse, or 0.014 and 0.0653 lb/MMBtu of heat input. The average of the two stack test values, 0.0397 lb/MMBtu, as well as the annual heat input from bagasse (from AOR data) was used (see Appendix A, Tables A-2).

Emissions for the 2-year period of 1999 to 2000 were selected for the baseline actual SO_2 emissions (Tables A-4 and 2-1).

Nitrogen Oxides

The NO_x emission factors used in the past AOR reporting were based on current AP-42 factors of either 20 or 24 lb/10^3 gallons for fuel oil combustion, while NO_x emission factors for bagasse burning were based on annual stack testing ranging from 1.339 to 1.778 lb/ton of bagasse (see Appendix A, Table A-1).

To determine the baseline actual emissions from fuel oil combustion, the current AP-42 factor for distillate oil of 24 lb/10^3 gallons, along with the annual fuel oil usage from AOR data, was used.

Baseline actual NO_x emissions from bagasse burning were calculated based on annual NO_x compliance test data conducted over the last 10 years (see Appendix A, Table A-5). The compliance test averages, in lb/MMBtu, were determined for each year. Rule 62-210.370(2)(d)1.a., F.A.C. requires that, when using annual stack test results to calculate baseline actual emissions, a minimum 5-year period that encompasses the 2-year period for which emission estimates are being made must be used, if adequate data is available. To comply with this requirement, in order to determine actual emissions for 1997, the year 1997 and the following 4 years (1998 to 2001) were used. Using the compliance test averages, a 5-year average NO_x emission factor in lb/MMBtu was determined for 1997 (see Appendix A, Table A-5). Using the annual bagasse usage rate for the boiler (from the AOR data), the annual emissions for 1997 were then determined (refer to Appendix A). This process was repeated for each year until the year 2003, when 4 following years of stack test data are not available. Therefore, for the years 2003 and beyond, the 5-year average of 2002 to 2006 was used. Emissions for the 2-year period of 1999 to 2000 were selected for the baseline actual NO_x emissions from bagasse firing (see Table 2-1 and Appendix A, Table A-4).

Carbon Monoxide

The CO emission factors used in the past AOR reporting were based on current AP-42 factors of 5 lb/10^3 gallons for fuel oil combustion, while CO emission factors for bagasse burning were based on annual stack testing ranging from 0.533 to 4.457 lb/ton of bagasse (see Appendix A, Table A-1).

To determine the baseline actual emissions from fuel oil combustion, the current AP-42 factor for No. 2 fuel oil of 5 lb/10^3 gallons, along with the annual fuel usage from AOR data, was used.

Baseline actual CO emissions from bagasse burning were calculated based on annual CO compliance test data conducted over the last 10 years (see Appendix A, Table A-5). The baseline actual CO emissions were based on 5-year average CO emissions, and were calculated in a manner similar to the baseline actual NO_x emissions for bagasse burning in compliance with Rule 62-210.370(2)(d)1.a., F.A.C. Emissions for the 2-year period of 1999 to 2000 were selected for the baseline actual CO emissions from bagasse firing (see Table 2-1 and Appendix A, Table A-4).

Particulate Matter/PM_{10}

The PM emission factors used in the past AOR reporting were based on current AP-42 factors of either 0.1 or 2 lb/10^3 gallons for fuel oil combustion, while PM emission factors for bagasse burning were based on annual stack testing ranging from 0.022 to 0.151 lb/ton of bagasse (see Appendix A, Table A-1).

To determine the baseline actual emissions from fuel oil combustion, the current AP-42 factor of 2 lb/10^3 gallons, along with the annual fuel usage from AOR data, was used.

Baseline actual PM emissions from bagasse burning were calculated based on annual PM compliance test data conducted over the last 10 years (see Appendix A, Table A-5). The baseline actual PM emissions were based on 5-year average PM emissions, and were calculated in a manner similar to the baseline actual NO_x emissions for bagasse burning. Emissions for the 2-year period of 2003 through 2004 were selected for the baseline actual PM emissions from bagasse firing (see Table 2-1 and Appendix A, Table A-4).

PM_{10} emissions reported in the AOR have generally been based on 85 percent of PM emissions for fuel oil firing, and 93 percent of PM emissions for bagasse firing. The 85 percent assumption for fuel oil firing was used to calculate the baseline actual emissions. The PM_{10} baseline actual emissions for bagasse firing were calculated using a ratio of AP-42 emission factors for PM and

PM_{10} for bagasse firing, which results in approximately 97.1 percent of PM assumed to be PM_{10}. Emissions for the 2-year period of 2003 through 2004 were selected for the baseline actual PM emissions (see Table 2-1 and Appendix A).

Volatile Organic Compounds

The VOC emission factors used in the past AOR reporting were based on current AP-42 factors of 0.2 lb/10^3 gallons for fuel oil combustion, while VOC emission factors for bagasse burning were based on annual stack testing ranging from 0.007 to 0.821 lb/ton of bagasse (see Appendix A, Table A-1).

To determine the baseline actual emissions from fuel oil combustion, the current AP-42 factor of 0.2 b/10^3 gallons, along with the annual fuel usage from AOR data, was used.

Baseline actual VOC emissions from bagasse burning were calculated based on annual VOC compliance test data conducted over the last ten years (see Appendix A, Table A-5). The baseline actual VOC emissions were based on 5-year average VOC emissions, and were calculated in a manner similar to the baseline actual NO_x emissions for bagasse burning. Emissions for the 2-year period of 1999 through 2000 were selected for the baseline actual VOC emissions from bagasse firing (see Table 2-1 and Appendix A, Table A-4).

Sulfuric Acid Mist

The SAM emission factor used in the past AOR reporting was based on the sulfur content of the No. 2 fuel oil used along with AP-42 factors (range of 0.1 to 0.285 lb/10^3 gallons). SAM emissions from the boiler when burning bagasse were based on a special stack test conducted in 1997, which showed SAM emissions were 0.05 lb/ton bagasse

The current AP-42 factor for SO_3 emissions (5.7*S lb/10^3 gallons) for fuel oil firing was used to determine the baseline actual SAM emissions from fuel oil combustion. The SO_3 emissions were then converted to H_2SO_4 by multiplying by the ratio of molecular weights (98/80). The resulting factor, along with the annual fuel usage from AOR data, was used to determine baseline actual emissions.

SAM emissions from the boiler when burning bagasse, based on special stack tests conducted in 1997, are shown in Appendix A, Table A-5. These are the only stack tests available for the boiler for SAM. The SAM emissions were 0.05 lb/ton bagasse, or 0.0072 lb/MMBtu. This stack test result as well as the annual heat input from bagasse (from AOR data) was used to estimate baseline actual emissions from bagasse firing (see Appendix A, Table A-2). Emissions for the 2-year period of 1999 through 2000 were selected for the baseline actual SAM emissions (Tables A-4 and 2-1).

Lead

The Pb emission factors used in the past AOR reporting were based on current AP-42 factors of 1.22×10^{-3} or 1.51×10^{-3} lb/10^3 gallons for fuel oil combustion. Pb emission factors for bagasse burning were based on AP-42 factors for wood firing of 4.45×10^{-4} lb/ton, or 2.45×10^{-5} lb/ton bagasse, based on industry average test data of 3.4×10^{-6} lb/MMBtu or less.

The current AP-42 factor for Pb of 9 lb/10^{12} Btu (1.22×10^{-6} lb/10^3 gallons), along with the annual fuel usage from AOR data, was used to determine the baseline actual emissions from fuel oil combustion. The extensive bagasse analysis from the Clewiston Mill was used to determine the baseline actual Pb emissions for bagasse burning. The average factor of 3.06×10^{-5} lb/MMBtu from the bagasse analysis was used. This is a conservative assumption, since some of the Pb in the fuel would be collected in the wet cyclones and ESP on Boiler No. 7. However, since the same assumption is used for future actual emissions, this would result in an overestimation of the net increase in emissions due to the project.

Emissions for the 2-year period of 1999 through 2000 were selected for the baseline actual Pb emissions from bagasse firing (see Table 2-1 and Appendix A, Table A-4).

Mercury

Hg emissions have not been reported in the AORs for the boiler. Therefore, Hg emissions due to fuel oil combustion were calculated using the AP-42 emission factor of 3 lb/10^{12} Btu (4.05×10^{-4} lb/10^3 gallons), along with the annual fuel usage from AOR data, to determine the baseline actual emissions.

There are no emission factors available for Hg emissions from boilers for bagasse firing. Therefore, the extensive bagasse analysis from the Clewiston mill was used to determine the baseline actual Hg emissions for bagasse burning. The average factor of 1.18×10^{-6} lb/MMBtu from the bagasse analysis was used. This is a conservative assumption, since some of the Hg in the fuel would be collected in the wet cyclones and ESP on Boiler No. 7. However, since the same assumption is used for future actual emissions, this would result in an overestimation of the net increase in emissions due to the project. Emissions for the 2-year period of 1999 through 2000 were selected for the baseline actual Hg emissions from bagasse firing (see Table 2-1 and Appendix A, Table A-4).

Fluorides

There are no emission factors available for fluoride emissions from boilers burning bagasse or No. 2 fuel oil. Refer to Appendix A tables and Appendix B for further explanation and references.

2.3.2 Projected Actual Emissions

Projected actual emissions for Boiler No. 7 are presented in Table 2-2. The derivation of the projected actual emissions is described below.

Operating Rate

"Projected actual emissions" for Boiler No. 7 were developed using the same operating factors used for the baseline actual emissions. The projected actual annual average heat input rate was derived from the highest year of heat input during the baseline period (3,966,303 MMBtu/yr during 2000). U.S. Sugar does not expect any increase in heat input on an annual basis due to the proposed project. The projected actual heat input represents the total heat input from bagasse and wood chip burning, with 2,350,083 MMBtu/yr coming from bagasse burning, and 1,616,220 MMBtu/yr coming from wood chip burning (based on 179,580 TPY maximum wood chip burning) (see Table 2-2). No. 2 fuel oil is not considered in the projected actual heat input, since wood chip burning represents the worst case for emissions, and the objective of the project is to replace fuel oil with wood chips. The derivation of the projected actual heat input (highest year of actual heat input) is shown in Appendix A, Table A-6.

Sulfur Dioxide

The emission factor for SO_2 emissions from bagasse burning used to determine the projected actual emissions (0.0397 lb/MMBtu) is the same as the emission factor used to calculate the baseline actual emissions for SO_2 from bagasse burning (see Appendix A, Tables A-2 and A-5). Emission factors for SO_2 emissions from wood chip burning based on AP-42 emission factors (0.025 lb/MMBtu) are lower than those of bagasse. To be conservative, the factor for bagasse was also used to determine the projected actual annual emissions due to wood chip burning for Boiler No. 7, as shown in Table 2-2.

Based on the factor for bagasse/wood chips, the SO_2 emission factor for 0.05 percent No. 2 fuel oil firing (7.1 lb/10^3 gal, or 0.0526 lb/MMBtu) is greater than that for bagasse/wood chips. Therefore, to determine projected actual SO_2 emissions, the highest 2-year average fuel oil utilization (486,431 MMBtu/yr for 2002 to 2003) was used, with the remainder of heat input due to bagasse/wood chips, as shown in Table 2-2.

Nitrogen Oxides

Emission factors for NO_x emissions from bagasse burning used to determine the projected actual emissions are based on the maximum 5-year average stack test results (0.2133 lb/MMBtu; see Appendix A, Table A-5). Emission factors for NO_x emissions from wood chip burning used to determine the projected actual emissions are based on stack tests burning 75 percent bagasse and 25 percent wood chips on a heat input basis performed in May 2005 (0.311 lb/MMBtu) (see excerpts from report in Appendix B). Although this factor is not based on 100 percent wood chip burning, it is much higher than the AP-42 factor for wood chip burning of 0.22 lb/MMBtu is, therefore, considered to be representative of 100 percent wood chip firing. Projected actual annual NO_x emissions for Boiler No. 7 are shown in Table 2-2.

Carbon Monoxide

Emission factors for CO emissions from bagasse burning used to determine the projected actual emissions are based on the maximum 5-year average stack test results (0.3230 lb/MMBtu; see Appendix A, Table A-5). No increase in the CO emission rate is expected when burning wood chips in comparison to burning bagasse; therefore, the emission factors used to determine the projected actual emissions are assumed to be the same as those for burning bagasse. Projected actual annual CO emissions for Boiler No. 7 are shown in Table 2-2.

PM/PM_{10}

Emission factors for PM emissions from bagasse burning used to determine the projected actual emissions are based on the maximum 5-year average stack test results (0.0198 lb/MMBtu; see Appendix A, Table A-5). The assumption from AP-42 that approximately 97.1 percent of PM is PM_{10}, used to calculate the baseline actual PM_{10} emissions, is also made to calculate the projected actual PM_{10} emissions. No increase in the PM/PM_{10} emission rate is expected when burning wood chips in comparison to burning bagasse; therefore, the emission factors used to determine the projected actual emissions are assumed to be the same as those for burning bagasse. Projected actual annual emissions for Boiler No. 7 are shown in Table 2-2.

Volatile Organic Compounds

Emission factors for VOC emissions from bagasse burning used to determine the projected actual emissions are based on the maximum 5-year average stack test results (0.0351 lb/MMBtu; see Appendix A, Table A-5). No increase in the VOC emission rate is expected when burning wood chips in comparison to burning bagasse; therefore, the emission factors used to determine the projected actual emissions are assumed to be the same as those for burning bagasse. Projected actual annual VOC emissions for Boiler No. 7 are shown in Table 2-2.

Sulfuric Acid Mist

Emission factors for SAM emissions from bagasse burning used to determine the projected actual emissions are the same as the emission factors used to calculate the baseline actual emissions for SO_2 from bagasse burning (0.0072 lb/MMBtu; see Appendix A, Tables A-2 and A-5). This same factor was used to determine projected actual emissions for SAM for both bagasse and wood chips, since SAM emissions are a function of SO_2 emissions, and the SO_2 emission factor used to determine projected actual emissions for bagasse and wood are the same. SAM emissions due to No. 2 fuel oil firing (0.35 lb/10^3 gal, or 0.0026 lb/MMBtu) are lower than those due to bagasse/wood chip firing. In addition, the purpose of the project is to reduce fuel oil consumption. Therefore, no fuel oil firing was considered in the projected actual emissions for SAM. Projected actual annual emissions for Boiler No. 7 are shown in Table 2-2.

Lead

The emission factor for Pb emissions from bagasse burning used to determine the projected actual emissions is the same as the emission factor used to calculate the baseline actual emissions for Pb from bagasse burning ($3.06x10^{-5}$ lb/MMBtu; see Table 2-2 and Appendix A, Table A-2). The emission factor for Pb emissions from wood chip burning used to determine the projected actual emissions is based on the AP-42 emission factor of $4.8x10^{-5}$ lb/MMBtu. It is assumed that all Pb in the fuel will be emitted to the atmosphere. Projected actual annual emissions for Boiler No. 7 are shown in Table 2-2.

Mercury

The emission factor for Hg emissions from bagasse burning used to determine the projected actual emissions is the same as the emission factor used to calculate the baseline actual emissions for Hg from bagasse burning ($1.18x10^{-6}$ lb/MMBtu; see Table 2-2 and Appendix A, Table A-2). The emission factor for Hg emissions from wood chip burning used to determine the projected actual emissions is based on the AP-42 emission factor of $3.5x10^{-6}$ lb/MMBtu for wood burning. Projected actual annual emissions for Boiler No. 7 are shown in Table 2-2.

2.3.3 Future Potential Emissions

The future potential annual emissions for Boiler No. 7 are presented in Table 2-3. The table shows the calculations for both the annual and short-term averaging periods. Annual emissions are calculated based on unlimited use of the boiler (i.e. 8,760 hr/yr). Based on the maximum 24-hour average heat input limit for the boiler (738 MMBtu/hr), future annual heat input to the Boiler No. 7 is 6,464,880 MMBtu/yr. No. 2 fuel oil burning is limited to 4,600,000, gal/yr with a maximum sulfur content of 0.05 percent. However, worst-case annual emissions are based on bagasse/wood chip firing.

The firing of wood chips will be limited to 1,616,220 MMBtu/yr, which represents 25 percent of the potential annual heat input to Boiler No. 7. This heat input corresponds to 179,580 TPY of wood chip firing (at 4,500 Btu/lb wet wood).

The emission factors used to calculate the future potential emissions are largely based on the current permit limits found in Permit No. 0510003-017-AV, with the emission factors for Pb and Hg for both bagasse and wood and NO_x for wood being the only exceptions. Factors for these two pollutants were based on the highest wood chip analysis results.

2.4 Effects on Other Emission Units

Only one other emission unit at the U.S. Sugar Clewiston mill may potentially be affected (i.e., increased process rates or increased actual air emission rates) due to the firing of wood chips in Boiler No. 7. Wood chips would be supplied to Boiler No. 7 by the Bagasse Conveying and Handling System. Since the wood chips would be replacing No. 2 fuel oil, there may be a small increase in actual PM emissions from the transport of the wood chips to Boiler No. 7. Total emissions from the Bagasse Handling and Conveying System in the off-season have previously been estimated at 1.99 TPY PM and 0.94 TPY PM_{10} (*Boiler No. 8 Permit Revision* application, Golder Associates, June 2006). If it is assumed that the entire system will increase throughput by 25 percent (a highly conservative assumption) during the off-season, the increase in PM/PM_{10} emissions would be 0.50 TPY PM and 0.25 TPY PM_{10}.

TABLE 2-1
SUMMARY OF BASELINE ACTUAL EMISSIONS FROM BOILER NO. 7
U.S. SUGAR-CLEWISTON MILL

Source Description	Pollutant Emission Rate (TPY) [a]										
	SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluorides
Average Actual Emissions of Highest 2-Year Period											
	'99-'00	'99-'00	'99-'00	'03-'04	'03-'04	'99-'00	--	'99-'00	'99-'00	'99-'00	--
Boiler No. 7	77.2	379.9	542.4	31.3	30.1	60.04	0.0	12.92	0.05	0.003	0.0

TPY = Tons per year.

Notes:
[a] Refer to tables in Appendix A for derivation.

TABLE 2-2
PROJECTED ACTUAL EMISSIONS FOR BOILER NO. 7
U.S. SUGAR-CLEWISTON MILL

Pollutant	Emission Factor	Ref.	Activity Factor[a]		Annual Emissions (TPY)
SO_2	0.0397 lb/MMBtu from Bagasse/Wood	1	3,479,873 MMBtu/yr		69.00
	0.0526 lb/MMBtu from Fuel Oil	2	486,431 MMBtu/yr		12.79
				Total:	***81.79***
NO_x	0.2133 lb/MMBtu from Bagasse	4	2,350,083 MMBtu/yr		250.69
	0.311 lb/MMBtu from Wood	1	1,616,220 MMBtu/yr		251.32
				Total:	***502.01***
CO	0.3230 lb/MMBtu from Bagasse	4	2,350,083 MMBtu/yr		379.58
	0.3230 lb/MMBtu from Wood	3	1,616,220 MMBtu/yr		261.05
				Total:	***640.63***
PM	0.0198 lb/MMBtu from Bagasse	4	2,350,083 MMBtu/yr		23.32
	0.0198 lb/MMBtu from Wood	3	1,616,220 MMBtu/yr		16.04
				Total:	***39.36***
PM_{10}	0.0193 lb/MMBtu from Bagasse	5	2,350,083 MMBtu/yr		22.66
	0.0193 lb/MMBtu from Wood	3	1,616,220 MMBtu/yr		15.58
				Total:	***38.24***
VOC	0.0351 lb/MMBtu from Bagasse	4	2,350,083 MMBtu/yr		41.19
	0.0351 lb/MMBtu from Wood	3	1,616,220 MMBtu/yr		28.33
				Total:	***69.52***
SAM	0.0072 lb/MMBtu from Bagasse	1	2,350,083 MMBtu/yr		8.40
	0.0072 lb/MMBtu from Wood	3	1,616,220 MMBtu/yr		5.78
				Total:	***14.18***
Lead	3.06E-05 lb/MMBtu from Bagasse	6	2,350,083 MMBtu/yr		0.04
	4.8E-05 lb/MMBtu from Wood	7	1,616,220 MMBtu/yr		0.04
				Total:	***0.07***
Mercury	1.18E-06 lb/MMBtu from Bagasse	6	2,350,083 MMBtu/yr		0.001
	3.5E-06 lb/MMBtu from Wood	7	1,616,220 MMBtu/yr		0.003
				Total:	***0.004***

[a] Activity factors based on actual maximum 2-year average heat input and fuel usage in AORs, as well as stack testing. Heat input rates based on 3,966,303 MMBtu/yr as the total heat input. Heat input from Wood based on 179,580 TPY wood. For SO_2, future actual fuel oil firing is assumed. See Tables A-5 through A-6.

References:
1. Based on stack tests. See Table A-5.
2. AP-42 factor of 142*S lb/1,000 gallon (where S = 0.05%), and 135,000 Btu/gallon for Fuel Oil.
3. Emission factor for wood is assumed to be the same as bagasse, since no increase is expected due to wood chip burning.
4. Maximum reported 5-year average rates from stack testing. See Table A-5.
5. PM_{10} is assumed to be approximately 97.1 percent of PM. See Table A-2.
6. Based on average value from bagasse fuel analysis for Clewiston Mill.
7. AP-42 factor for trace elements from wood residue combustion.

TABLE 2-3
FUTURE POTENTIAL EMISSIONS FOR BOILER NO. 7
U.S. SUGAR-CLEWISTON MILL

			Short-Term [a]		Annual Average [b]	
Pollutant	Emission Factor	Ref.	Activity Factor	Emissions (lb/hr)	Activity Factor	Emissions (TPY)
SO_2	0.17 lb/MMBtu from Bagasse	1	812 MMBtu/hr	138.04	4,848,660 MMBtu/yr	412.14
	0.17 lb/MMBtu from Wood	2	0 MMBtu/hr	0.00	1,616,220 MMBtu/yr	137.38
			Total:	*138.04*	*Total:*	*549.51*
NO_x	0.25 lb/MMBtu from Bagasse	1	0 MMBtu/hr	0	4,848,660 MMBtu/yr	606.08
	0.3110 lb/MMBtu from Wood	3	812 MMBtu/hr	252.53	1,616,220 MMBtu/yr	251.32
			Total:	*252.53*	*Total:*	*857.40*
CO	0.70 lb/MMBtu from Bagasse	1	812 MMBtu/hr	568.40	4,848,660 MMBtu/yr	1697.03
	0.70 lb/MMBtu from Wood	2	0 MMBtu/hr	0.00	1,616,220 MMBtu/yr	565.68
			Total:	*568.40*	*Total:*	*2262.71*
PM	0.03 lb/MMBtu from Bagasse	1	812 MMBtu/hr	24.36	4,848,660 MMBtu/yr	72.73
	0.03 lb/MMBtu from Wood	2	0 MMBtu/hr	0.00	1,616,220 MMBtu/yr	24.24
			Total:	*24.36*	*Total:*	*96.97*
PM_{10}	0.03 lb/MMBtu from Bagasse	1	812 MMBtu/hr	24.36	4,848,660 MMBtu/yr	72.73
	0.03 lb/MMBtu from Wood	2	0 MMBtu/hr	0.00	1,616,220 MMBtu/yr	24.24
			Total:	*24.36*	*Total:*	*96.97*
VOC	0.212 lb/MMBtu from Bagasse	1	812 MMBtu/hr	172.14	4,848,660 MMBtu/yr	513.96
	0.212 lb/MMBtu from Wood	2	0 MMBtu/hr	0:00	1,616,220 MMBtu/yr	171.32
			Total:	*172.14*	*Total:*	*685.28*
SAM	0.017 lb/MMBtu from Bagasse	1	812 MMBtu/hr	13.80	4,848,660 MMBtu/yr	41.21
	0.017 lb/MMBtu from Wood	2	0 MMBtu/hr	0.00	1,616,220 MMBtu/yr	13.74
			Total:	*13.80*	*Total:*	*54.95*
Lead	1.18E-04 lb/MMBtu from Bagasse	4	0 MMBtu/hr	0	4,848,660 MMBtu/yr	0.29
	4.8E-05 lb/MMBtu from Wood	5	812 MMBtu/hr	0.04	1,616,220 MMBtu/yr	0.04
			Total:	*0.04*	*Total:*	*0.32*
Mercury	2.53E-06 lb/MMBtu from Bagasse	4	0 MMBtu/hr	0	4,848,660 MMBtu/yr	0.006
	3.5E-06 lb/MMBtu from Wood	5	812 MMBtu/hr	0.003	1,616,220 MMBtu/yr	0.003
			Total:	*0.003*	*Total:*	*0.009*

[a] Short-term emissions based on 812 MMBtu/hr heat input and worst-case fuel (either 100 percent bagasse or 100 percent wood chips).

[b] Annual average emissions based on 738 MMBtu/hr heat input (75percent from bagasse burning and 25 percent from wood chip burning) and 8,760 hr/yr operation.

References:
1. Based on permit limit for carbonaceous fuel (see Permit No. 0510003-017-AV).
2. Permit limit for wood chips assumed to be the same as that of bagasse.
3. Based on stack tests. See Table A-5.
4. Based on maximum value from bagasse fuel analysis for Clewiston Mill.
5. AP-42 factor for trace elements from wood residue combustion.

3.0 AIR QUALITY REVIEW REQUIREMENTS

Federal and state air regulatory requirements for a major new or modified source of air pollution are discussed in Subsections 3.1 through 3.3. The applicability of these regulations to the proposed U.S. Sugar modification is presented in Subsection 3.4. These regulations must be satisfied before the proposed projects can be approved.

3.1 National and State Ambient Air Quality Standards

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 or modified sources to be located in or near these areas may be subject to more stringent air permitting requirements.

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

3.2 PSD Requirements

3.2.1 General Requirements

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

A "major facility" is defined as one that has the "potential-to-emit" 100 TPY or more of any pollutant regulated under the CAA, if the facility belongs to one of 28 listed source categories. Otherwise, a major facility is one that has the potential to emit 250 TPY or more "Potential-to-emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

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 (i.e., a "major modification"). The PSD significant emission rates are listed in Table 3-2. The determination of whether a significant net increase in emissions will occur is based on comparison of "baseline actual emissions" to "projected actual emissions" for all emission units affected by the proposed project, including any contemporaneous increases or decreases which have occurred at the facility in the last 5 years. See Subsection 3.4.2.1 for further discussion of these concepts.

The EPA class designation and allowable PSD increments are also 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 1977 CAA amendments. Congress promulgated areas as Class I (international parks, national wilderness areas, memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21 PSD of Air Quality. The state of Florida has adopted PSD regulations that are equivalent to the federal PSD regulations (Rule 62-212.400, F.A.C.). Major facilities and major modifications are required to undergo the following analyses related to PSD for each pollutant for which the emissions increase is significant:

- Control technology review,
- Source impact analysis,
- Air quality analysis (monitoring), and
- Additional impact analyses.

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

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's Guidelines for Determining 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 units 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 or modified 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 facility. BACT must, as a minimum, demonstrate compliance with New Source Performance Standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

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 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 I and II increments, a source impact analysis must be performed. 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 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 impacts are assumed not to have a significant adverse effect on air quality. Additional modeling, taking into account other emission sources, is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling, including other emission sources, is required in order to demonstrate compliance with AAQS and PSD increments.

EPA has issued guidance related to significant impact levels for Class I areas, as shown in Table 3-1. 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 reviews, the 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 into the PSD process is part of implementing the NSR regulations. Because the process of developing the regulations will be lengthy, EPA believes that the guidance concerning the significant impact levels is appropriate to assist states in implementing the PSD permit process.

Various lengths of record for meteorological data can be used for impact analyses. 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 based on an evaluation of measured 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 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:

- The actual emissions representative of facilities in existence on the applicable baseline date; and
- The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM_{10}, or February 8, 1988, for NO_2, 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:

- Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM_{10}, and after February 8, 1988, for NO_2 and
- 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:

- The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM_{10}; and February 8, 1988, in the case of NO_2.
- The trigger date, which is August 7, 1977, for SO_2 and PM_{10}; and February 8, 1988, for NO_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.

3.2.4 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 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/modified 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 [illegible] *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 monitoring analysis must be conducted. This exemption states that FDEP may exempt a proposed major stationary facility or major modification from the monitoring requirements, with respect to a particular pollutant, if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2.

3.3 Source Information/GEP 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 FDEP has adopted identical regulations (Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

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

  $Hg = H + 1.5L$

  where: Hg = GEP stack height,

  H = Height of the structure or nearby structure, and

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

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

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

3.3.1 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 or proposed modification [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).

3.4 Potentially Applicable 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 1970, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

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

"***Reconstruction***" means the replacement of components of an affected facility to such an extent that:

- The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and
- It is technologically and economically feasible to meet the applicable standards set forth in this part.
- 40 CFR 60.5 defines "***fixed capital cost***" as the capital needed to provide all the depreciable components. 40 CFR 60.2 defines "***capital expenditure***" as:

    > "an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable

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

Federal NSPS exist for fossil-fuel and wood-fired industrial-commercial-institutional steam boilers constructed or modified after June 19, 1984. The NSPS are contained in 40 CFR 60, Subpart Db. The NSPS contain emission limits for SO_2, PM, and NO_x for oil firing and emission limits for PM for wood firing. Wood is defined in the NSPS to include bark, wood, and wood residue. Subpart Db is potentially applicable to Boiler No. 7.

Federal NSPS also exist for fossil-fuel-fired steam generators for which construction or modification occurred after August 17, 1971 (40 CFR 60, Subpart D). The NSPS contains emission limits for PM, SO_2, and NO_x for liquid fossil fuel and wood residue firing. However, 40 CFR 60, Subpart Db, contains a provision that any unit subject to Subpart Db is not subject to Subpart D.

3.4.2 <u>National Emission Standards for Hazardous Air Pollutants</u>

MACT standards, codified in 40 CFR 63, Subpart DDDDD, were promulgated for Industrial, Commercial, and Institutional Boilers and Process Heaters on September 13, 2004, with an effective date of November 12, 2004. Subpart DDDDD regulates HAP metals (with PM as a surrogate), hydrogen chloride (HCl), and Hg emissions from existing large solid fuel-fired industrial boilers. The compliance date for existing boilers is September 13, 2007.

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

> ***Reconstruction***, unless otherwise defined in a relevant standard, means the replacement of components of an affected or previously nonaffected source to such an extent that:
>
> (1). The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source; and

(2) It is technologically and economically feasible for the reconstructed source to meet the relevant standard(s) established by the Administrator pursuant to Section 112 of the Act. Upon reconstruction, an affected source, or a stationary source that becomes an affected source, is subject to relevant standards for new sources, including compliance dates, irrespective of any change in emission of hazardous air pollutants from that source.

3.4.3 Florida Rules

Emission limitations applicable to carbonaceous fuel burning equipment are contained in Rule 62-296.410, F.A.C. This rule limits PM emissions, as well as visible emissions, from such equipment.

3.5 Source Applicability

3.5.1 Area Classification

The project site is located in Hendry County, which has been designated by EPA and FDEP as an attainment or unclassifiable area for all criteria pollutants. The county is also classified as a PSD Class II area for PM_{10}, SO_2, and NO_2; therefore, the NSR will follow PSD regulations pertaining to such designations.

3.5.2 PSD Review

Pollutant Applicability

The U.S. Sugar Clewiston mill is considered to be an existing major stationary facility because potential emissions of at least one PSD-regulated pollutant exceed 100 TPY (for example, potential NO_x and CO emissions currently exceed 100 TPY). Therefore, PSD review is required for any pollutant for which the net increase in emissions due to the modification is greater than the PSD significant emission rates (see Table 3-2).

The net increase in emissions due to the proposed modification at the U.S. Sugar Clewiston mill is summarized in Table 3-3. For Boiler No. 7, the baseline actual and future actual emissions are based on information from Section 2.0.

As shown in the top section of Table 3-3, the increase in emissions due to wood chip firing exceeds the significant emission rate for only NO_x. For this pollutant, the PSD regulations require that all contemporaneous emissions increases and decreases be included in a netting analysis to determine PSD applicability. These are shown in the bottom portion of Table 3-3.

Source Impact Analysis

A source impact analysis was performed for NO_x emissions resulting from the proposed modification. A regional haze analysis was also performed to evaluate the impacts of visibility reduction in the PSD Class I areas due to the project. This analysis is presented in Sections 6.0 and 7.0.

Ambient Monitoring

Based on the increase in emissions from the proposed modification (see Table 3-3), a pre-construction ambient monitoring analysis would be required for NO_2, and monitoring data would be 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 no *de minimis* monitoring concentration is specified for a pollutant, that pollutant is exempt from the pre-construction air monitoring requirements [40 CFR 52.21(i)(8)(ii)]. Furthermore, if no acceptable ambient monitoring method for the pollutant has been established by the EPA, monitoring is not required.

Pre-construction monitoring data for NO_2 can be exempted for this project because, as shown in Section 6.0, the proposed modification's NO_2 impacts are predicted to be less than 1 $\mu g/m^3$, annual average, which is less than the *de minimis* monitoring concentration of 14 $\mu g/m^3$, annual average for NO_2.

GEP Stack Height Analysis

All existing stacks at the U.S. Sugar mill currently comply with GEP stack height regulations. In addition, no new stacks are proposed as part of this project.

3.5.3 Emission Standards

New Source Performance Standards

Boiler No. 7 is currently subject to NSPS for industrial boilers, 40 CFR 60, Subpart Db, for fuel oil firing only, since bagasse fuel is not regulated under Subpart Db. Since the annual capacity factor for fuel oil firing is limited to 10 percent, only the opacity standards under Subpart Db are applicable (the NO_x emission standard is not applicable). However, on February 27, 2006, Subpart Db was revised to exempt from the PM emission limit and opacity limit for fuel oil firing any affected sources that burn only fuel oil containing no more than 0.3 percent weight percent sulfur. This can be construed to apply to Boiler No. 7 at any time that it is burning only No. 2 fuel oil.

The boiler will be undergoing a change in the method of operation by burning wood. This change will not increase actual PM emissions on an hourly basis, because wood chips have a higher heating value and lower moisture content compared to bagasse, and should combust more efficiently than bagasse. Therefore, the proposed project will not constitute a "modification" under the NSPS. However, Boiler No. 7 will be firing a new fuel (wood) which is subject to regulation under Subpart Db; therefore, the boiler will be subject to Subpart Db for wood firing.

There are no emission limits for SO_2 or NO_x for wood firing under Subpart Db. The applicable emission limit for PM is contained in §60.43b(h), as shown below:

> §60.43b Standard for Particulate Matter
>
> (h)(1) On or after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5).

Boiler No. 7 currently has a PM emission limit of 0.030 lb/MMBtu, which complies with Subpart Db.

The applicable opacity limit is contained in §60.43b(f), as shown below:

> (f) On and after the date on which the initial performance test is completed or is required to be completed under 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

Section 60.48b(a) requires that an affected facility subject to the opacity standard under §60.43b install and operate a continuous opacity monitoring system (COMS). Boiler No. 7 has implemented an approved alternative monitoring plan (AMP) for opacity while burning No. 2 fuel oil. This plan has been in affect since the boiler originally began operating in 1996. However, based on the 2006 revisions to Subpart Db, the opacity limit for fuel oil firing would no longer apply; therefore, the COMS requirement would no longer apply.

U.S. Sugar is proposing an AMP for wood chip firing, in lieu of the COMS. The AMP consists of complying with the compliance assurance monitoring (CAM) plan that has been submitted for approval in the Title V renewal application for the Clewiston mill. This plan is based upon the continuous monitoring of total power input to the ESP, and maintaining a minimum power input based on a 3-hour block average. This will also be consistent with the requirements for Boiler No. 7 under the NESHAP, Subpart DDDDD, which becomes effective in September 2007.

The proposed project will not constitute "reconstruction" under the NSPS. No physical changes are required to the boiler to accommodate wood firing. Therefore, no component parts are required to be replaced due to the project.

NESHAPs for Source Categories

EPA recently promulgated the MACT rule for industrial, commercial and institutional boilers and process heaters (40 CFR 63, Subpart DDDDD), and Boiler No. 7 is subject to this rule. The MACT rule regulates PM (as a surrogate for metallic HAPs), HCl, and Hg emissions from existing large solid fuel-fired industrial boilers. Boiler No. 7 is in the large solid fuel-fired subcategory, and is an "existing source" under the MACT since the boiler was constructed prior to January 13, 2003. The applicable emission limits for existing boilers for wood firing are 0.07 lb/MMBtu for PM [or

0.001 lb/MMBtu for total selected metals (TSM)], 0.09 lb/MMBtu for HCl, and $9x10^{-6}$ lb/MMBtu for Hg. The compliance date for existing boilers is September 13, 2007. U.S. Sugar will comply with the applicable standards by the compliance date.

As discussed in the NSPS paragraph of Subsection 3.5.3, the planned modifications to Boiler No. 7 represent zero percent of the cost of a new boiler. As a result, Boiler No. 7 will not be "reconstructed" for the purposes of the MACT rule, and the boiler will remain an "existing source" under the MACT rules.

State of Florida Standards

Boiler No. 7 is subject to Rule 62-296.410, F.A.C. This rule regulates carbonaceous fuel burning equipment and contains standards for opacity and PM. The standards applicable to Boiler No. 7 are 30-percent opacity (except 40-percent opacity is allowed for up to 2 minutes per hour) and a 0.2 lb M/MMBtu limit for carbonaceous fuel plus a 0.1 lb PM/MMBtu limit for fossil fuel. Boiler No. 7 will comply with these standards.

TABLE 3-1
NATIONAL AND STATE AAQS, ALLOWABLE PSD INCREMENTS, AND SIGNIFICANT IMPACT LEVELS ($\mu g/m^3$)

		AAQS			PSD Increments		Significant Impact Levels[d]	
Pollutant	**Averaging Time**	**National Primary Standard**	**National Secondary Standard**	**State of Florida**	**Class I**	**Class II**	**Class I (proposed)**	**Class II**
Particulate Matter[a] (PM_{10})	Annual Arithmetic Mean	50	50	50	4	17	0.2	1
	24-Hour Maximum[b]	150[b]	150[b]	150[b]	8	30	0.3	5
Sulfur Dioxide	Annual Arithmetic Mean	80	N/A	60	2	20	0.1	1
	24-Hour Maximum[e]	365[b]	N/A	260[b]	5	91	0.2	5
	3-Hour Maximum[b]	NA	1,300[b]	1,300[b]	25	512	1	25
Carbon Monoxide	8-Hour Maximum[b]	10,000[b]	10,000[b]	10,000[b]	N/A	N/A	N/A	500
	1-Hour Maximum[b]	40,000[b]	40,000[b]	40,000[b]	N/A	N/A	N/A	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	0.1	1
Ozone[a]	1-Hour Maximum	235[c]	235[c]	235[c]	N/A	N/A	N/A	N/A
	8-Hour Maximum	157	157	N/A	N/A	N/A	N/A	N/A
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	N/A	N/A	N/A N/A	N/A

Note: NA = Not applicable, *i.e.*, no standard exists.
PM_{10} = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.

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

[b]Short-term maximum concentrations are not to be exceeded more than once per year except for the PM_{10} AAQS (these do not apply to significant impact levels). The PM_{10} 24-hour AAQS is attained when the expected number of days per year with a 24-hour concentration above 150 $\mu g/m^3$ is equal to or less than 1. For modeling purposes, compliance is based on the sixth-highest 24-hour average value over a 5-year period.

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

[d]Maximum concentrations.

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

TABLE 3-2
PSD SIGNIFICANT EMISSION RATES AND *DE MINIMIS* MONITORING CONCENTRATIONS

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

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

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

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

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

TABLE 3-3
PSD CONTEMPORANEOUS AND PROJECT EMISSIONS NETTING ANALYSIS
WOOD CHIP BURNING PROJECT, U.S. SUGAR CLEWISTON

Source Description	Pollutant Emission Rate (TPY)										
	SO_2	NO_X	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluoride
Projected Actual Emissions											
Boiler No. 7 Woodchip Project [a]											
Bagasse burning	69.00	250.69	379.58	23.32	22.66	41.19	--	8.40	0.04	0.001	--
Wood Chip burning	12.79	251.32	261.05	16.04	15.58	28.33	--	5.78	0.04	0.003	--
Total- Projected Actual	**81.79**	**502.01**	**640.63**	**39.36**	**38.24**	**69.52**	**--**	**14.18**	**0.07**	**0.004**	**--**
Baseline Actual Emissions											
Boiler No. 7 [b]	77.21	379.92	542.42	31.32	30.14	60.04	--	12.92	0.05	0.003	--
Total - Baseline Actual	**77.21**	**379.92**	**542.42**	**31.32**	**30.14**	**60.04**	**--**	**12.92**	**0.05**	**0.003**	**--**
Increase Due to Project	**4.58**	**122.09**	**98.22**	**8.05**	**8.10**	**9.48**	**0.0**	**1.26**	**0.02**	**0.002**	**0.0**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10.0	7	0.6	0.1	3
Netting Triggered?	No	Yes	No	No	No	No	No	No	No	No	No
CONTEMPORANEOUS EMISSION CHANGES											
Boiler No. 7 Fuel Oil Firing 0510003-018-AC	[c]	0.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
3-Year Boiler Maintenance 0510003-022-AC	[c]	0.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Boiler No. 8 0510003-024-AC/PSD-FL-333A (11/21/03)	[c]	[d]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Bagasse Handling System 0510003-024-AC/PSD-FL-333A	[c]	0.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Salt Silo @ Molasses Plant 0510003-025-AC	[c]	0.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
New White Sugar Dryer No. 2 0510003-026-AC (2/11/05)	[c]	3.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Boiler No. 1 and 2 Fuel Oil Firing 0510003-027-AC (2/05)	[c]	38.6 [e]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Boiler No. 4 Fuel Oil Firing 0510003-029-AC	[c]	1.8 [e]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Boiler No. 7 - Wood Chips N/A- Temporary authorization	[c]	0.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Boiler No. 8 - NESHAPs revisions 0510003-030-AC/PSD-FL-333B (4/7/06)	[c]	0.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
TV- Misc. Corrections AC 0510003-031-AC	[c]	0.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Limestone Silo @ Molasses Plant 0510003-033-AC	[c]	0.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
New Boiling House Lime System 0510003-034-AC	[c]	0.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Boiler No. 1 and 2 Oil Firing Mod. 0510003-036-AC (8/2/06)	[c]	0.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Boiler No. 8 Steam Rate Increase 0510003-037-AC (draft 2/5/07)	[c]	0.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
New White Sugar Dryer No. 2 - PM emission increase 0510003-038-AC (12/22/06)	[c]	0.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Boiler 1, 2 and 4 Oil Firing Cap 0510003-039-AC (9/20/06)	[c]	32.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Boiler No. 8- remove requirement to monitor wet cyclone pressure drop 0510003-040-AC	[c]	0.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Total Contemporaneous Emission Changes	[c]	35.0	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
TOTAL NET CHANGE	**4.58**	**157.1**	**98.2**	**8.05**	**8.10**	**9.48**	**0.00**	**1.26**	**0.02**	**0.00**	**0.00**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10.0	7	0.6	0.1	3
PSD REVIEW TRIGGERED?	No	Yes	No	No	No	No	No	No	No	No	No

Footnotes:
[a] See Table 2-2 for projected actual emissions calculations for Boiler No. 7.
[b] See Table 2-1 for baseline actual emissions from Boiler No. 7.
[c] Netting not triggered for this pollutant; therefore contemporaneous emissions are not accounted for.
[d] PSD triggered for this pollutant; therefore all previous contemporaneous emission changes are wiped clean for this pollutant.
[e] These increases were superceded by permit 0510003-039-AC issued 9/20/06.

4.0 AMBIENT MONITORING ANALYSIS

4.1 Monitoring Requirements

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 major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2). As discussed in the paragraphs under Pollutant Applicability in Subsection 3.4.2, NO_x is subject to PSD pre-construction monitoring requirements for the proposed modification because the net increase in emissions due to the project exceeds the PSD significant emission rate for this pollutant.

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

An exemption from the pre-construction ambient monitoring requirements is also available if the predicted increase in ambient concentrations, due to the proposed modification, is less than specified *de minimis* concentrations.

Pre-construction monitoring data for NO_2 can be exempted for this project because, as shown in Section 6.0, the proposed modification's NO_2 impacts are predicted to be less than 1 $\mu g/m^3$, annual average, which is less than the *de minimis* monitoring concentration of 14 $\mu g/m^3$, annual average for NO_2.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

5.1 Requirements

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

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

In the case of the proposed project, Boiler No. 7 is undergoing a change in the method of operation. As a result, BACT applies to each pollutant for which Boiler No. 7 has a net emissions increase as a result of the modification [40 CFR 52.21(j)(3)]. Therefore, NO_x emissions from Boiler No. 7 require a BACT analysis. The BACT analysis is presented in the following sections.

5.2 Nitrogen Oxides

5.2.1 Previous BACT Determinations

As part of the BACT analysis, a review was performed of previous BACT determinations for similar biomass-fired industrial, commercial, and electric utility boilers listed in the RACT, BACT, LAER Clearinghouse (RBLC) on EPA's website. From this information, BACT determinations issued within the last 10 years were identified. A summary of these BACT determinations is presented in Table 5-1.

Previous BACT determinations for NO_x emissions from bagasse-fired boilers have ranged from 0.14 to 0.24 lb/MMBtu. From the previous BACT determinations, it is evident that NO_x BACT determinations for bagasse-fired industrial and commercial boilers have typically been based on selective non-catalytic reduction (SNCR) or good combustion practices.

Previous BACT determinations for NO_x emissions from biomass-fired boilers (other than bagasse) have ranged from 0.0.075 to 0.68 lb/MMBtu. From the previous BACT determinations, it is evident that NO_x BACT determinations for these boilers have typically been based on SNCR, good combustion practices, low-NO_x burners (LNBs), or no emission controls. The lowest BACT determination of 0.075 lb/MMBtu on a 24-hour average was for a fluidized bed boiler with an SNCR. A fluidized bed boiler is a significantly different technology from a spreader stoker boiler, such as Boiler No. 7. The next lowest BACT emission limit was 0.12 lb/MMBtu on a 24-hour average for a wood waste-fired boiler.

5.2.2 Control Technology Feasibility

The technically feasible NO_x controls for Boiler No. 7 are shown in Table 5-2. As shown in the table, there are four primary types of NO_x abatement methods, with various techniques within each method. Each available technique was listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency. It is also indicated if Boiler No. 7 will employ the specific technique.

5.2.3 Potential Control Method Descriptions

Removal of Nitrogen

Ultra-Low Nitrogen Fuel – The fuels combusted in Boiler No. 7 will be bagasse, wood chips, and No. 2 fuel oil. Combustion of these fuels results in emissions of NO_x that are lower than conventional fuels due to the characteristically low levels of nitrogen associated with these fuels. U.S. Sugar will control NO_x emissions from Boiler No. 7 through the use of low nitrogen content fuels.

Chemical Reduction of NO_x

Selective Catalytic Reduction – Selective Catalytic Reduction (SCR) uses a catalyst to react injected ammonia to chemically reduce NO_x. The catalyst has a finite life in flue gas and some ammonia slips through without being reacted. SCR has historically used precious metal catalysts, but can now also use base metal and zeolite catalyst materials. Catalyst poisoning due to bagasse combustion excludes SCR as an option for NO_x control for Boiler No. 7. Technical difficulties associated with applying

SCR include no operating experience on bagasse, and likely premature catalyst deactivation due to chemical poisoning of the catalyst resulting from the alkali content of the ash. Based on previous analysis of ash from bagasse firing in Boiler No. 7, the ash contains 0.3 percent sodium, 15 percent potassium, 6 percent phosphorus, 9 percent sulfur, and over 5 percent chlorides (all as oxides). Wood ash has similar characteristics to ash from bagasse.

The high moisture content of bagasse (approximately 50 percent moisture) is also a concern for catalyst operation. The SCR placement would be prior to the air preheater, where the flue gas temperature is in the range of 600 to 1,000 degrees Fahrenheit (°F). High particulate loading prior to the wet cyclone collector would, therefore, be a concern. This could lead to catalyst fouling, reduced NO_x removal efficiency, and failure of the system.

Selective Non-Catalytic Reduction-- In SNCR, ammonia or urea is injected within the boiler or in ducts in a region where the temperature is between 1,600 and 2,000°F. This technology is based on temperature ionizing the ammonia or urea instead of using a catalyst or non-thermal plasma. The temperature window for SNCR is very important because outside of it either more ammonia slips through the system or more NO_x is generated than is being chemically reduced.

SNCR has been demonstrated as a feasible technology for biomass combustion and can achieve NO_x reductions up to 50 percent. Boiler No. 8 at U.S. Sugar has an SNCR system with an emission limit of 0.14 lb/MMBtu. The SNCR system operation has proven satisfactory.

Hybrid SCR/SNCR -- Combination SCR and SNCR systems have been developed as an alternative to traditional SNCR systems. However, the hybrid system would suffer from the same issues of SCR alone applied to a bagasse boiler, i.e., premature catalyst poisoning and catalyst fouling. Therefore, this technology was not considered further.

Reducing Residence Time at Peak Temperature

Air Staging of Combustion -- Combustion air is divided into two streams. The first stream is mixed with fuel in a ratio that produces a reducing flame. The second stream is injected downstream of the flame and creates an oxygen-rich zone. Boiler No. 7 will utilize over-fire air, which acts as air staging of combustion.

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

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

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

Reducing Peak Temperature

Flue Gas Recirculation -- Recirculation of cooled flue gas reduces combustion temperature by diluting the oxygen content of the combustion air and by causing heat to be diluted in a greater mass of flue gas. Heat in the flue gas can be recovered by a heat exchanger. This reduction of temperature lowers the thermal NO_x concentration that is generated. Flue gas recirculation (FGR) is considered technically feasible on the existing Boiler No. 7; however, this technology would have little effect on NO_x emissions while potentially increasing CO and VOC emissions and decreasing boiler efficiency. FGR is not known to be employed on any bagasse boiler currently.

Natural Gas Reburning -- In a boiler outfitted with reburn technology, a set of natural gas burners is installed above the primary combustion zone. Natural gas is injected to form a fuel-rich, oxygen-deficient combustion zone above the main firing zone. Nitrogen oxide (NO), created by the combustion process in the main portion of the boiler, drifts upward into the reburn zone and is converted to molecular nitrogen. The technology requires no catalysts, chemical reagents, or changes to any existing burners. Typical reburn systems also incorporate redesign of the combustion air system to provide less excess air (LEA). Natural gas reburn is a feasible technology for Boiler No. 7. However, natural gas is not currently available at the Clewiston mill. In addition, a reburn system would require displacement of 20 percent of the bagasse with natural gas, which would result in a natural gas cost of millions of dollars annually, while resulting in, at best, 25 percent reduction of NO_x emissions. Therefore, this technology was not considered further.

Over-Fire Air -- When primary combustion uses a fuel-rich mixture, use of overfire air (OFA) completes the combustion. Because the mixture is always off-stoichiometric when combustion is occurring, the temperature is reduced. After all other stages of combustion, the remainder of the fuel is oxidized in the OFA. Boiler No. 7 will utilize an OFA system to promote vigorous mixing of the combustion gases to maximize combustion efficiency and reduce pollutant emissions. The OFA system injects hot air at high velocities into the furnace.

Less Excess Air -- Excess airflow combustion has been correlated to the amount of NO_x generated. Limiting the net excess airflow can limit NO_x content of the flue gas. Boiler No. 7 already utilizes a combustion system that minimizes the amount of excess air in the furnace.

Combustion Optimization -- Combustion optimization refers to the active control of combustion. The active combustion control measures seek to find optimum combustion efficiency and to control combustion at that efficiency. Boiler No. 7 will be optimized for maximum combustion efficiency. However, the nature of bagasse fuel results in continuous changes to optimization points.

Reduce Air Preheat -- Reducing air preheat means reducing the temperature of the combustion air entering the boiler. This acts to reduce peak flame temperature, thereby reducing NO_x emissions. However, this technique can also lead to high CO and VOC emissions. Boiler No. 7 already utilizes ambient air for overfire air, therefore this technique is already employed.

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

LNBs can be employed for natural gas and fuel oil firing. This type of burner is already being utilized on Boiler No. 7.

5.2.4 Economic Analysis

The top-ranked feasible add-on control technology, as shown in Table 5-2, is SNCR. To evaluate the economic impact of SNCR on the project, a cost quote was obtained from FuelTech. The cost analysis for SNCR is presented in Table 5-3.

The operational scenario, presented in Table 5-3, represents the SNCR system being applied only to wood chip burning, which is the proposed project. U.S. Sugar plans to burn wood chips primarily during the off-season, but at other times also, when bagasse is not available. Under this scenario, the

SNCR system would be operated during 5 months of the year during the off-season and other very limited times. The total capital investment (direct capital costs plus indirect capital costs and project contingency) of the SNCR system for Boiler No. 7 is estimated at $2,500,000. The total annualized cost of applying SNCR is estimated at $508,000 per year. The baseline NO_x emissions are based on the increase due to wood chip burning (122.1 TPY; see Table 3-3). The SNCR system will achieve 50 percent NO_x reduction on wood chips. The resulting cost effectiveness of adding SNCR is estimated at over $8,300 per ton of NO_x removed.

5.2.5 Environmental and Energy Impacts

As shown in Section 6.0, the maximum predicted annual NO_2 impacts for the proposed project are less than the EPA significant impact levels. Additional NO_x controls would result in an insignificant reduction of ambient impacts that are already below EPA significance levels for both Class I and II areas.

Energy penalties occur with both SNCR and natural gas reburn. SNCR will require inputs of energy, water, and urea. The urea and energy requirements will equal approximately $0.02 per gallon of reactant. Based on an estimated 34 gallons per hour of urea solution, the urea (water) and energy cost will be $120,000 per year. There will also be a loss in efficiency of the boiler, due to the injection of an aqueous stream and subsequent evaporation in the boiler.

5.2.6 BACT Selection

For U.S. Sugar, the combination of good combustion practices, over-fire air, low excess air, and low nitrogen content fuel (bagasse and wood chips), and No. 2 fuel oil can achieve the maximum amount of emissions reduction economically feasible, is technically feasible, and is demonstrated in practice. Additional controls should be rejected as BACT for Boiler No. 7 for the following reasons:

- Wood chips represent a low-nitrogen-containing fuel.
- SCR has not been demonstrated in practice on a wood-fired boiler. Wood-fired boilers operate in a harsher environment compared to only oil and gas-fired boilers. There are serious concerns related to poisoning and fouling of the catalyst due to constituents in the ash, moisture of the exhaust gas stream, etc.
- The burning of wood chips will be limited on an annual basis.
- The cost of SNCR applied to wood chip burning is over $8,300/ton of NO_x removed.

TABLE 5-1
BACT DETERMINATIONS FOR NO_X EMISSIONS FROM BIOMASS-FIRED INDUSTRIAL & COMMERCIAL BOILERS

Company	State	RBLC ID	Permit Date	Fuel	Throughput	Emission Limits: As Provided in LAER/BACT Clearinghouse	Emission Limits: Converted to lb/MMBtu[a]	Control Equipment Description	Removal Efficiency %
Boilers firing Bagasse:									
US Sugar Corp. - Clewiston Blr No. 8	FL	FL-0257	11/18/2003	Bagasse	936 MMBtu/hr	0.14 lb/MMBtu	0.140	SNCR, Good Combustion & Operating Practices	50
Rio Grande Valley Sugar Growers	TX	TX-0461[b]	10/10/2003	Bagasse	288 MMBtu/hr	48 lb/hr	0.167	Good Combustion Practices	--
				Bagasse	194 MMBtu/hr	32.4 lb/hr	0.167	Good Combustion Practices	--
				Bagasse	202 MMBtu/hr	33.6 lb/hr	0.167	Good Combustion Practices	--
				Bagasse	137 MMBtu/hr	22.68 lb/hr	0.166	Good Combustion Practices	--
				Bagasse	562 MMBtu/hr	135 lb/hr	0.240	Good Combustion Practices	--
US Sugar Corp. - Clewiston Blr No. 4	FL	PSD-FL-272A[d]	5/18/2001	Bagasse	633 MMBtu/hr	0.2 lb/MMBtu	0.200	Good Combustion Practices	--
Atlantic Sugar Association - Blr No. 5	FL	PSD-FL-078B[d]	6/7/2001	Bagasse	255.3 MMBtu/hr	0.16 lb/MMBtu	0.160	Good Combustion Practices	--
US Sugar Corp. - Clewiston	FL	FL-0034	11/29/2000	Bagasse	633 MMBtu/hr	0.2 lb/MMBtu	0.200	Good Combustion Practices	--
US Sugar Corporation - Boiler No. 4	FL	FL-0248	11/19/1999	Bagasse	633 MMBtu/hr	0.2 lb/MMBtu	0.200	Good Combustion Practices	--
Boilers firing Wood and Wood products:									
Sierra Pacific Industries - Skagit Co Lumber Mill	WA	WA-0327[b]	1/25/2006	Bark & Waste Wood	430 MMBtu/hr	0.13 lb/MMBtu (Calendar Day)	0.130	SNCR	48
International Biofuels Inc	VA	VA-0298[b]	12/13/2005	Wood/Woodpaste	77 MMBtu/hr	0.22 lb/MMBtu	0.220	--	--
				Wood/Woodpaste	43 MMBtu/hr	0.22 lb/MMBtu	0.220	--	--
City of Virginia, VA Power Co, Laurention Energy	MN	MN-0058	6/30/2005	Wood	230 MMBtu/hr	0.15 lb/MMBtu (30-day avg)	0.150	SNCR	50
Hibbing Puc/Laurention Energy Authority	MN	MN-0059	6/30/2005	Wood	230 MMBtu/hr	0.15 lb/MMBtu (30-day rolling avg)	0.150	SNCR	50
Darrington Energy LLC	WA	WA-0329	2/11/2005	Wood Waste	403 MMBtu/hr	0.12 lb/MMBtu (24-hr avg)	0.120	SNCR	--
Inland Paperboard and Packaging (Gaylord)	LA	LA-0188	11/23/2004	Bark	787.5 MMBtu/hr	351.38 lb/hr	0.446	Overfire air; Low NO_X burners; good combustion	--
Public Service of New Hampshire - Schiller Station	NH	NH-0013	10/25/2004	Wood & Tree Products	720 MMBtu/hr	0.075 lb/MMBtu (24-hr avg)	0.075	Fluidized Bed Boiler & SNCR	65
Louisiana-Pacific Corporation	WI	WI-0223	6/17/2004	Wood	19.4 MMBtu/hr	8.9 lb/hr	0.459	Good Combustion Practices	--
				Wood	23.8 MMBtu/hr	16.2 lb/hr	0.681	Good Combustion Practices	--
Biomass Energy	OH	OH-0269	1/5/2004	Wood	175 MMBtu/hr	0.44 lb/MMBtu (for each of 7 boilers)	0.440	SNCR	80
Deltic Timber Corporation	AR	AR-0075	8/20/2003	Wood Waste & Bark	64.3 MMBtu/hr	0.3 lb/MMBtu	0.300	Oven Fire Air & Dry Low NO_X Combustion	--
Wellborn Cabinet Inc	AL	AL-0213	4/16/2003	Wood Waste	29.5 MMBtu/hr	14.75 lb/hr	0.500	Boiler Design & Combustion Control	--
Del-Tin Fiber LLC	AR	AR-0072	2/28/2003	Wood Waste	291 MMBtu/hr	87.2 lb/hr	0.300	Low NO_X burners & SNCR	--
West Frazer (South) Inc.	AR	AR-0065	11/7/2002	Wood Waste	29.63 MMBtu/hr	0.3 lb/MMBtu	0.300	Overfire air & Low NO_X Combustion	--
Sierra Pacific Industries - Aberdeen Div	WA	WA-0298	10/17/2002	Waste Wood	310 MMBtu/hr	0.15 lb/MMBtu (24-hr avg)	0.150	SNCR & Boiler Design	--
Meadwestvaco Kentucky Inc	KY	KY-0085	2/27/2002	Bark	631 MMBtu/hr	0.4 lb/MMBtu	0.400	--	--
Martinsville Thermal, LLC - Thermal Ventures	VA	VA-0268	2/15/2002	Wood	120 MMBtu/hr	0.4 lb/MMBtu	0.400	Good Combustion Practices	--
District Energy St. Paul Inc	MN	MN-0046	11/15/2001	Wood	550 MMBtu/hr	0.15 lb/MMBtu	0.150	SNCR	--
Temple-Inland Forest Products Corporation	TX	TX-0345	9/28/2001	Wood	40 MMBtu/hr	57.2 lb/hr	1.430	--	--
International Paper Company - Riegelwood Mill	NC	NC-0092	5/10/2001	Wood Waste	600 MMBtu/hr	0.35 lb/MMBtu	0.350	Good Combustion Practices	--
Duke Energy	OH	OH-0244	11/24/1999	Wood	28.7 MMBtu/hr	0.604 lb/MMBtu	0.604	--	--
Wheelabrator Sherman Energy Company	ME	ME-0026	4/9/1999	Wood	315 MMBtu/hr	0.25 lb/MMBtu (30-day avg)	0.250	Good Combustion Practices	--
Trigen Biopower	GA	GA-0116	11/24/1998	Wood Waste	265.1 MMBtu/hr	66.3 lb/hr	0.250	Bubling Fluidized Bed Combustion	--
Gulf States Paper Corp	AL	AL-0122	10/14/1998	Wood	98 MMBtu/hr	0.3 lb/MMBtu	0.300	--	--
Sierra Pacific Industries - Quincy	CA	CA-0930	5/13/1998	Wood	245.3 MMBtu/hr	56.4 lb/hr	0.230	SNCR	--
Wellborn Cabinet Inc	AL	AL-0107	2/3/1998	Wood	29.5 MMBtu/hr	13.57 lb/hr	0.460	Boiler design & comb. Control: oxygen trim, staged comb., steam injection, & overfire air.	31
				Wood Waste	57.2 MMBtu/hr	0.25 lb/MMBtu	0.250	Staged Combustion	
Gulf States Paper Corporation	AL	AL-0116	12/10/1997	Bark	775 MMBtu/hr	0.3 lb/MMBtu	0.300	Low NO_X natural gas & fuel oil burner	50
Plum Creek Mfg - Evergreen Facility	MT	MT-0007	2/15/1997	Hog Fuel	225 MMBtu/hr	104 lb/hr	0.462	--	--
Boilers firing other Biomass:									
Archer Daniels Midland Company	ND	ND-0022	5/1/2006	Hulls	280 MMBtu/hr	0.2 lb/MMBtu (30-day rolling avg)	0.200	Combustion Control	30
Powerminn 9090 LLC	MN	MN-0057	10/23/2002	Manure	792 MMBtu/hr	0.16 lb/MMBtu (30-day avg)	0.160	SNCR	50
Archer Daniels Midland Co. - Northern	ND	ND-0018	7/9/1998	Hulls	200 MMBtu/hr	0.2 lb/MMBtu	0.200	--	--
				Hulls	280 MMBtu/hr	0.2 lb/MMBtu	0.200	--	--

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2007. 0.160

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

[b] From the draft BACT determination.

[c] Assuming 8,760 hr/yr.

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

TABLE 5-2
NOx CONTROL TECHNOLOGY FEASIBILITY ANALYSIS FOR BOILER NO. 7

NO_x Abatement Method	Technique Now Available	Estimated Efficiency	Technically Feasible? (Y/N)	Demonstrated? (Y/N)	Rank Based on Control Efficiency	Employed by Boiler No. 7? (Y/N)
1. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data	Y	Y	4	Y
2. Chemical reduction of NO_x	Selective Catalytic Reduction (SCR)	35 - 80%	N	N	NA	N
	Selective Non-Catalytic Reduction (SNCR)	35 - 50%	Y	Y	2	N
	Hybrid SNCR/SCR	60 - 90%	N	N	NA	N
3. Reducing residence time at peak temperature	Air Staging of Combustion	50 - 65%	Y	Y	1	Y
	Fuel Staging of Combustion	50 - 65%	Y	Y	1	N
	Inject Steam	50 - 65%	Y	Y	1	N
4. Reducing peak temperature	Flue Gas Recirculation (FGR)	15 -25%	Y	Y	3	N
	Natural Gas Reburning (NGR)	15 -25%	N	N	NA	N
	Over Fire Air (OFA)	15 -25%	Y	Y	3	Y
	Less Excess Air (LEA)	15 -25%	Y	Y	3	Y
	Combustion Optimization	15 -25%	Y	Y	3	Y
	Reduce Air Preheat	15 -25%	Y	Y	3	Y
	Low NO_x Burners (LNB)	15 -25%	Y	Y	3	Y

Note: NA = Not Applicable

TABLE 5-3
COST EFFECTIVENESS OF SNCR SYSTEM WHEN OPERATED IN OFF-CROP SEASON, U.S. SUGAR CLEWISTON

Cost Items	Cost Factors[a]	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
NOxOUT SNCR System	FuelTech quote dated 10/27/06	$1,000,000
Urea Storage tank, vales, piping	10,000 gal	$100,000
Instruments and Controls	Included	$0
Freight	5% of equipment cost	$50,000
Taxes	6% Sales Tax	$60,000
Total PEC:		$1,210,000
Direct Installation Costs		
Installation of SNCR	35% of equipment cost	$423,500
Emissions Monitoring	15% of equipment cost	$181,500
Foundation and Structure Support	8% of equipment cost	$96,800
Spare Parts	5% of equipment cost	$60,500
Total Direct Installation Costs		$762,300
Total DCC (PEC + Direct Installation):		$1,972,300
INDIRECT CAPITAL COSTS (ICC):		
Engineering	2% of PEC (for excluded items)	$24,200
Construction and field expenses	2% of PEC (for excluded items)	$24,200
Contractor Fees	10% of PEC (for excluded items)	$121,000
Startup	1% of PEC	$12,100
Performance test +	1% of PEC	$12,100
Total ICC:		$193,600
PROJECT CONTINGENCY		
Contingencies (retrofit cost)	15% of (DCC+ICC)	$324,885
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	$2,490,785
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	20 hours/week, $16/hr, 153 days/yr (21.86 weeks/yr)	$6,994
Supervisor	15% of operator cost	$1,049
(2) Maintenance	Engineering estimate, 2% PEC	$24,200
(3) Urea Cost	34.1 gal/hr, $0.85/gal, 153 days/yr, 24 hr/day	$106,433
(4) Electricity - Operating	$0.06/kWh, 153 days/yr, 24 hr/day	$15,000
Total DOC:		$153,676
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	$19,346
Property Taxes	1% of total capital investment	$24,908
Insurance	1% of total capital investment	$24,908
Administration	2% of total capital investment	$49,816
Total IOC:		$118,977
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	$235,130
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	$507,784
BASELINE NO_X EMISSIONS (TPY) :	Table 3-3: Net Increase Due to Project (TPY)	122.1
MAXIMUM NO_X EMISSIONS (TPY) :	50% reduction (TPY)	61.1
REDUCTION IN NO_X EMISSONS (TPY):	(TPY)	61.1
COST EFFECTIVENESS:	$ per ton of NO_X Removed	$8,318

Footnotes:

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

6.0 AIR QUALITY IMPACT ANALYSIS

The EPA and FDEP rules require that applicants for major new facilities and major modifications of existing facilities perform a source impact analysis for each applicable pollutant (40 CFR 52.21(k)). This air quality impact analysis is provided to demonstrate that U.S. Sugar's increase in NO_x emissions due to the Boiler No. 7 wood chip firing project will comply with the AAQS and allowable PSD Class I and II increments.

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. This section presents the air quality modeling methodology and results.

6.1 General Air Quality Modeling Analysis Approach

The air quality impact analysis of the U.S. Sugar mill was conducted following EPA and FDEP modeling guidelines for assessing compliance with the AAQS and PSD increments. The U.S. Sugar Clewiston mill is located approximately 103 km from the PSD Class I area of the Everglades National Park (ENP) (see Figure 6-1). Therefore, NO_2 concentrations were also predicted for the ENP.

More detailed descriptions of the models, along with the emission inventory, meteorological data, and receptor grids used in the analysis are presented in the following sections.

6.2 Significant Impact Analysis Approach

6.2.1 Site Vicinity

A significant impact analysis was performed to determine the magnitude and distance to which the project's NO_2 impacts are predicted to exceed the EPA's significant impact levels at any location beyond the Clewiston mill's restricted boundaries. The EPA's significant NO_2 impact level is 1 $\mu g/m^3$ for the annual averaging period for the PSD Class II areas.

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

6.2.2 PSD Class I Areas

Generally, if the facility undergoing the modification is within 200 km of a PSD Class I area, then a significant impact analysis is also performed to evaluate the impact due to the project alone at the PSD Class I area. Because the ENP is located within 200 km of the U.S. Sugar mill, the maximum predicted NO_2 impact due to the proposed project at this area is compared to the proposed EPA's NO_2 significant impact level for PSD Class I areas. The NO_2 PSD Class I significant impact level is 0.1 $\mu g/m^3$ for the annual averaging period (refer to Table 3-1). These recommended levels have never been promulgated as rules, but are the currently accepted criteria to determine whether a proposed project will incur a significant impact on a PSD Class I area.

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

6.3 Air Modeling Analysis Approach

6.3.1 General Procedures

Because there will be a significant increase in NO_x emissions from the Boiler No. 7 wood chip burning project, air modeling analyses are required to determine if the project-only impacts are predicted to be greater than the significant impact levels. These analyses consider impacts due to the proposed project alone. Air quality impacts are predicted using 5 years of meteorological data and selecting the highest predicted ground-level concentrations for comparison to the significant impact levels. To predict the maximum annual and short-term concentrations for the proposed project, a high-resolution receptor grid was used along with 5 years of hourly meteorology data. If the modification's impacts are greater than the significant impact levels, the air modeling analyses must consider other nearby sources and background concentrations to predict a total concentration for comparison to AAQS and PSD increments.

Generally, when using 5-years of meteorological data for the analysis, the highest annual and the HSH short-term concentrations are compared to the applicable AAQS and allowable PSD increments. The HSH concentration is calculated for a receptor field by:

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

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

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

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

6.3.2 PSD Class I Analysis

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

6.4 Model Selection

The selection of an air quality model to calculate air quality impacts was based on its applicability to simulate impacts in areas surrounding the U.S. Sugar Clewiston mill, as well as at the PSD Class I area of interest. Two air quality dispersion models were selected and used in these analyses to address air quality impacts for the proposed project. These models were:

- The American Meteorological Society/EPA dispersion model (AERMOD) and
- The California Puff model (CALPUFF).

6.4.1 AERMOD

The area surrounding the Clewiston mill is mostly rural and flat. The facility is located within a short distance of the southwestern shore of Lake Okeechobee. Based on these features, the AERMOD dispersion model (Version 07026) was selected to evaluate the pollutant impacts due to the facility alone and in combination with other emission sources.

For this analysis, the EPA regulatory default options were used to predict all maximum impacts. These options include:

- Final plume rise at all receptor locations,
- Stack-tip downwash,
- Buoyancy-induced dispersion,
- Default wind speed profile coefficients,
- Default vertical potential temperature gradients, and
- Calm wind processing.

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

The EPA and FDEP recommend that the AERMOD model be used to predict pollutant concentrations at receptors located within 50 km of source. The AERMOD model calculates hourly concentrations based on hourly meteorological data. The AERMOD model is applicable for most applications since it is recognized as containing the latest scientific algorithms for simulating plume behavior in all types of terrain. For evaluating plume behavior within the building wake of structures, the AERMOD model incorporates the Plume Rise Model Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). AERMOD can predict pollutant concentrations for averaging times of annual and 24, 8, 3, and 1 hour.

The AERMOD model was used to predict the maximum pollutant concentrations due to the project in nearby areas surrounding the site. The AERMOD model was also used to predict the maximum pollutant concentrations due to the project's emissions together with appropriate background sources. The predicted concentrations were then compared to the applicable AAQS and PSD Class II increments.

6.4.2 CALPUFF

At distances beyond 50 km from a source, the CALPUFF model, Version 5.711a (EPA, 2003), is recommended for use by the EPA and the Federal Land Manager (FLM). Major features of the CALPUFF model are presented in Table 6-2. The CALPUFF model is a long-range transport model applicable for estimating the air quality impacts in areas that are more than 50 km from a source. The CALPUFF model is maintained by the EPA on the SCRAM internet website. The methods and assumptions used in the CALPUFF model are based on the latest recommendations for modeling analysis as presented in the following reports:

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

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

The CALPUFF model was used to perform a significant impact analysis for the proposed project at the ENP PSD Class I area. In addition, the CALPUFF model was used to predict the proposed project's maximum potential impacts on air quality related values (AQRV) at the PSD Class I areas. Visibility and acid deposition are AQRVs at the ENP.

6.5 Meteorological Data

6.5.1 AERMOD

Meteorological data used in the AERMOD model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations from the National Weather Service (NWS) offices located at the Palm Beach International Airport (PBI) and twice-daily upper air soundings collected at the Florida International University (FIU) in Miami for the years 2001 through

2005. The NWS office at PBI is located approximately 82 km (51 miles) east of the Clewiston mill and is the closest primary weather station to study area considered to have meteorological data representative of the site. The meteorological data from this NWS station have been used for numerous air modeling studies within the sugar industry and for the U.S. Sugar Clewiston mill. Concentrations were predicted using 5 years of hourly meteorological data from 2001 through 2005.

A unique feature of AERMOD is its incorporation of land use parameters for the processing of boundary layer parameters used for the dispersion. Based on the most recent regulatory guidance, the land use parameters should be representative of the data measurement site (i.e., NWS at PBI). Land-use data, representing the average surface roughness, albedo, and Bowen ratio that exist within a 3-km radius of the NWS at PBI were extracted from 1-degree land use files from the U.S. Geographical Survey (USGS) using the AERSURFACE program. AERSURFACE currently extracts land-use data in 12 wind direction sectors covering 360 degrees. These parameters were compared to those estimated in the same manner around the project site. Based on this comparison, the values for all parameters were similar.

6.5.2 CALPUFF

For CALPUFF, the air modeling analysis was conducted using the latest meteorological and geophysical databases that have been developed for use with the most recent versions of CALPUFF. These datasets were prepared by the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) for the purpose of conducting visibility impairment analyses under the BART Rule.

For this project, the VISTAS Florida CALMET domain with 4-km spacing (VISTAS refined Domain 2) was used. The data cover the period from 2001 to 2003. Golder obtained these datasets from the FDEP. The FDEP and FLM have recommended their use for PSD projects.

6.6 Emission Inventory

6.6.1 Significant Impact Analysis

The emissions for the U.S. Sugar Clewiston mill used in the significant impact analysis are summarized in Table 6-3. The proposed increase in NO_x emissions for Boiler No. 7 were used in the PSD Class II and Class I significant impact analyses. The annual NO_x emission increase from the proposed project is 122.1 TPY (see Table 3-3). The short-term increase is based on assuming the boiler operating at its maximum 24-hour heat input rate of 738 MMBtu/hr, and using the increase in NO_x due to wood chip firing (0.311 lb/MMBtu for wood chip firing minus 0.2133 lb/MMBtu for bagasse firing = 0.0977 lb/MMBtu). The stack and operating parameters are presented in Table 6-4. Source locations are in UTM East and North coordinates UTM Zone 17.

The proposed increase in NO_2 air quality impacts for the Boiler No. 7 wood chip burning project are predicted to be less than the PSD Class II significant impact level. Therefore, additional modeling analyses are not required to demonstrate compliance with the AAQS and PSD Class II increments for NO_2.

For the PSD Class I area, the proposed increase in NO_2 air quality impacts for the Boiler No. 7 wood chip burning project is predicted to be less than the PSD Class I significant impact levels. Therefore, additional modeling analyses to demonstrate compliance with the allowable PSD Class I increments are not required.

6.6.2 AAQS and PSD Class II Analyses

As discussed in Section 6.6.1, the maximum impacts from the proposed Boiler No. 7 wood chip burning project were predicted to be less than the NO_2 significant impact levels. As a result, a cumulative source analysis is not required to demonstrate compliance with the NO_2 AAQS and allowable PSD Class II increments.

6.6.3 PSD Class I Analysis

A list of background NO_x PSD facilities was not required because the PSD Class I significant impact levels were not exceeded by the proposed project. The predicted NO_2 impacts within the Class I area of the ENP were used to support the AQRV analysis presented in Section 7.0. For the Class I impact analysis, the net NO_x emissions increase due to the Boiler No. 7 wood chip burning project was modeled for NO_2 impacts for various averaging times.

6.7 Building Downwash Effects

In accordance with current EPA policy, the effect of building downwash effects on predicted air quality concentration levels was evaluated. Building dimensions for all key U.S. Sugar Clewiston mill buildings were entered into the EPA-developed Building Profile Input Program (BPIP, Version 04274) to obtain direction-specific building heights, lengths, and widths for all U.S. Sugar Clewiston mill point sources. The BPIP model was used in its PRIME mode to generate the appropriate PRIME downwash input dimensions for the AERMOD model. The direction-specific building dimensions are input for Hb and lb for 36 radial directions, with each direction representing a 10-degree sector. The Hb is the building height and lb is the lesser of the building height or projected width. In addition, the AERMOD model inputs three additional building parameters that further describe the building/wake configuration:

- Projected length of the building along the flow direction,
- Along-flow distance from the stack to the center of the upwind face of the projected building, and
- Cross-flow distance from the stack to the center of the upwind face of the projected building.

The building dimensions considered in the air modeling analysis for the U.S. Sugar Clewiston mill are presented in Table 6-5.

6.8 Receptor Locations

6.8.1 Site Vicinity

To determine the maximum impact for all pollutants and averaging times in the vicinity of the U.S. Sugar Clewiston mill, a general Cartesian grid was used to predict concentrations on and beyond the facility property line out to 4 km. Receptors were located at the following intervals and distances from the origin:

- Every 100 m from the site fence line to 2,000 m and
- Every 500 m from 2,000 to 4,000 m.

Elevations and hill scale heights were calculated for each receptor using the AERMAP (06341) terrain processor and 7.5-minute Digital Elevation Model (DEM) data from the USGS.

6.8.2 Class I Area

For determining the project's impacts at the PSD Class I areas, pollutant concentrations were predicted in an array of 126 discrete receptors located at the PSD Class I area of the ENP. These receptors were obtained from the NPS.

6.9 Background Concentrations

Because an AAQS analysis is not required for the proposed project, it is not necessary to determine NO_2 background concentrations for use in the modeling analysis.

6.10 Air Quality Impact Analysis Results

6.10.1 PSD Class II Significant Impact Analysis

The maximum NO_2 concentrations predicted for the Boiler No. 7 wood chip burning project only for comparison to the PSD Class II significant impact levels are presented in Table 6-6. Because the project's impacts are predicted to be below the PSD Class II significant impact levels, additional modeling analysis is not required to be performed to address compliance with AAQS and PSD Class II increments.

6.10.2 PSD Class I Significant Impact Analysis

The maximum NO_2 concentrations predicted for the Boiler No. 7 wood chip burning project only for the PSD Class I significant impact analysis at the ENP presented in Table 6-7. All of the maximum impacts are predicted to be below the PSD Class I significant impact levels.

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

6.11 Conclusions

Based on the air quality modeling analyses, the maximum pollutant concentrations due to the proposed Boiler No. 7 modification's emissions are predicted to be less than the PSD Class II and Class I significant impact levels for all pollutants. As a result, more detailed modeling analyses are not required to demonstrate compliance with AAQS and allowable PSD increments. The results of the modeling analysis demonstrate the proposed project will not have a significant affect on air quality and will comply with all applicable AAQS and PSD increments.

TABLE 6-1
MAJOR FEATURES OF THE AERMOD MODEL, VERSION 04300

AERMOD Model Features
• Plume dispersion/growth rates are determined by the profile of vertical and horizontal turbulence, vary with height, and use a continuous growth function.
• In a convective atmosphere, uses three separate algorithms to describe plume behavior as it comes in contact with the mixed layer lid; in a stable atmosphere uses a mechanically mixed layer near the surface.
• Polar or Cartesian coordinate systems for receptor locations can be included directly or by an external file reference.
• Urban model dispersion is input as a function of city size and population density; sources can also be modeled individually as urban sources.
• Stable plume rise: uses Briggs equations with winds and temperature gradients at stack top up to half-way up to plume rise. Convective plume rise: plume superimposed on random convective velocities.
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash.
• Has capability of simulating point, volume, area, and multi-sized area sources.
• Accounts for the effects of vertical variations in wind and turbulence (Brower *et al.*, 1998).
• Uses measured and computed boundary layer parameters and similarity relationships to develop vertical profiles of wind, temperature, and turbulence (Brower *et al.*, 1998).
• Concentration estimates for 1-hour to annual average times.
• Creates vertical profiles of wind, temperature, and turbulence using all available measurement levels.
• Terrain features are depicted by use of a controlling hill elevation and a receptor point elevation.
• Modeling domain surface characteristics are determined by selected direction and month/season values of surface roughness length, Albedo, and Bowen ratio.
• Contains both a mechanical and convective mixed layer height, the latter based on the hourly accumulation of sensible heat flux.
• The method of Pasquill (1976) to account for buoyancy-induced dispersion.
• A default regulatory option to set various model options and parameters to EPA-recommended values.
• Contains procedures for calm-wind and missing data for the processing of short term averages.

Note: AERMOD = The American Meteorological Society and Environmental Protection Agency Regulatory Model.
Source: Paine *et al.*, 2004.

TABLE 6-2
MAJOR FEATURES OF THE CALPUFF MODEL, VERSION 5.11a

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

Note: CALPUFF = California Puff Model
Source: EPA, 2003.

TABLE 6-3
NO_x EMISSIONS USED IN SIGNIFICANT IMPACT ANALYSIS
U.S. SUGAR-CLEWISTON MILL

Emission Unit	Unit ID	Baseline Actual Emissions				Projected Actual Emissions			
		Short-Term		Long-Term		Short-Term		Long-Term	
		lb/hr	g/s	TPY	g/s	lb/hr	g/s	TPY	g/s
Boiler No. 7	B7	157.4 [a]	19.84	379.9 [b]	10.93	229.5 [c]	28.92	502.0 [d]	14.44

[a] Based on 738 MMBtu/hr heat input to the boiler and 0.2133 lb/MMBtu NO_x emission factor from bagasse.

[b] See Table 2-1.

[c] Based on 738 MMBtu/hr heat input to the boiler and 0.311 lb/MMBtu NO_x emission factor from wood.

[d] See Table 2-2.

TABLE 6-4
SUMMARY OF STACK AND OPERATING PARAMETERS AND LOCATIONS FOR BOILER NO. 7, U.S. SUGAR CLEWISTON

		UTM Coordinates [a]		Stack and Operating Parameters					Exit			
		X	Y	Height		Diameter		Flow Rate	Temperature		Velocity	
Emission Unit	ISCST3 ID	km	km	ft	m	ft	m	(acfm)	°F	K	ft/s	m/s
Boiler No. 7	B7	506.1	2957.0	225	68.58	8.0	2.44	309,924	272	406.5	102.8	31.3

[a] Universal Transverse Coordinates, Zone 17, NAD17.

TABLE 6-5
SUMMARY OF BUILDING STRUCTURES CONSIDERED IN THE AIR MODELING ANALYSIS
U.S. SUGAR CLEWISTON

Structure	Height		Length[a]		Width[b]	
	ft	m	ft	m	ft	m
Boiler No. 8 Structures						
Boiler No. 8 Building	98	29.9	127	38.8	72	22.1
Boiler No. 8 ESP	69	21.0	59	18.0	54	16.5
Refinery Buildings						
Electrical Equipment	100	30.5	96	29.1	28	8.4
Support Structure	130	39.6	96	29.1	76	23.2
Dryer Area	100	30.5	96	29.1	39	11.9
Screening & Distribution Towers	150	45.7	126	38.5	69	20.9
Specialty Packaging Facility	40	12.2	82	25.0	202	61.4
Packaging Facility	40	12.2	65	19.8	280	85.3
Warehouse	28	8.5	340	103.5	290	88.3
Electrical & Conditioning Equipment	24	7.3	60	18.2	52	15.9
Bulk Loading	40	12.2	84	25.7	54	16.4
Sugar Silos	136	41.5	112	34.0	68	20.8
Other Mill Buildings						
Pellet Warehouse	46	14.0	527	160.6	105	32.0
RO Plant	51	15.5	39	12.0	20	6.0
Storage and Safety Mechanic	35	10.6	61	18.5	55	16.8
Power House	34	10.4	116	35.3	142	43.3
Boiler No. 1&2 Building	67	20.5	119	36.2	84	25.6
Boiler No. 4 Building	88	26.7	61	18.5	55	16.8
Boiler No. 7 ESP	88	26.7	62	18.8	36	11.0
Boiler No. 7 Building	93	28.3	120	36.6	113	34.4
C Mill Building (C-Tandem)	82	25.0	223	68.0	97	29.6
Evaporators	100	30.5	186	56.8	140	42.6
B Mill Building (B-Tandem)	68	20.7	223	68.0	75	22.9
Process Building	94	28.6	243	74.1	145	44.1
Sugar Warehouse #3	55	16.8	140	42.7	780	237.7
Sugar Warehouse #4	55	16.8	140	42.7	1783	543.5
Sugar Warehouse #5	55	16.8	140	42.7	963	293.5
Clarifiers	56	17.1	100	30.5	124	37.8
Central Control Room	20	6.1	209	63.7	103	31.4
Cooling Tower	53	16.2	77	23.3	53	16.0
B_CPVS	100	30.5	74.9	22.8	50	15.4
Boiler No. 9 Building (Future)	88	26.8	60.8	18.5	50.7	15.5
PSD Baseline Buildings						
A Mill Building (A-Tandem)	69	21.0	243	74.1	67	20.4
Sugar Warehouse #1	37	11.3	391	119.0	104	31.6
Boiler No. 5&6 Building	56	17.1	118	36.0	66	20.1

[a] North-South dimension.

[b] East-West dimension.

TABLE 6-6
PSD CLASS II NO_2 SIGNIFICANT IMPACT ANALYSIS

Pollutant	Averaging Time	Concentration [a] (μg/m^3)	Receptor Location [b] Easting (m)	Receptor Location [b] Northing (m)	Time Period (YYMMDDHH)	EPA Significant Impact Level (μg/m^3)
NO_2	Annual	0.42	505550	2957300	01123124	1
		0.44	505550	2957300	02123124	
		0.48	505550	2957300	03123124	
		0.41	505450	2957200	04123124	
		0.43	505450	2957200	05123124	

Note: YY = Year; MM = Month; DD = Day; HH = Hour.

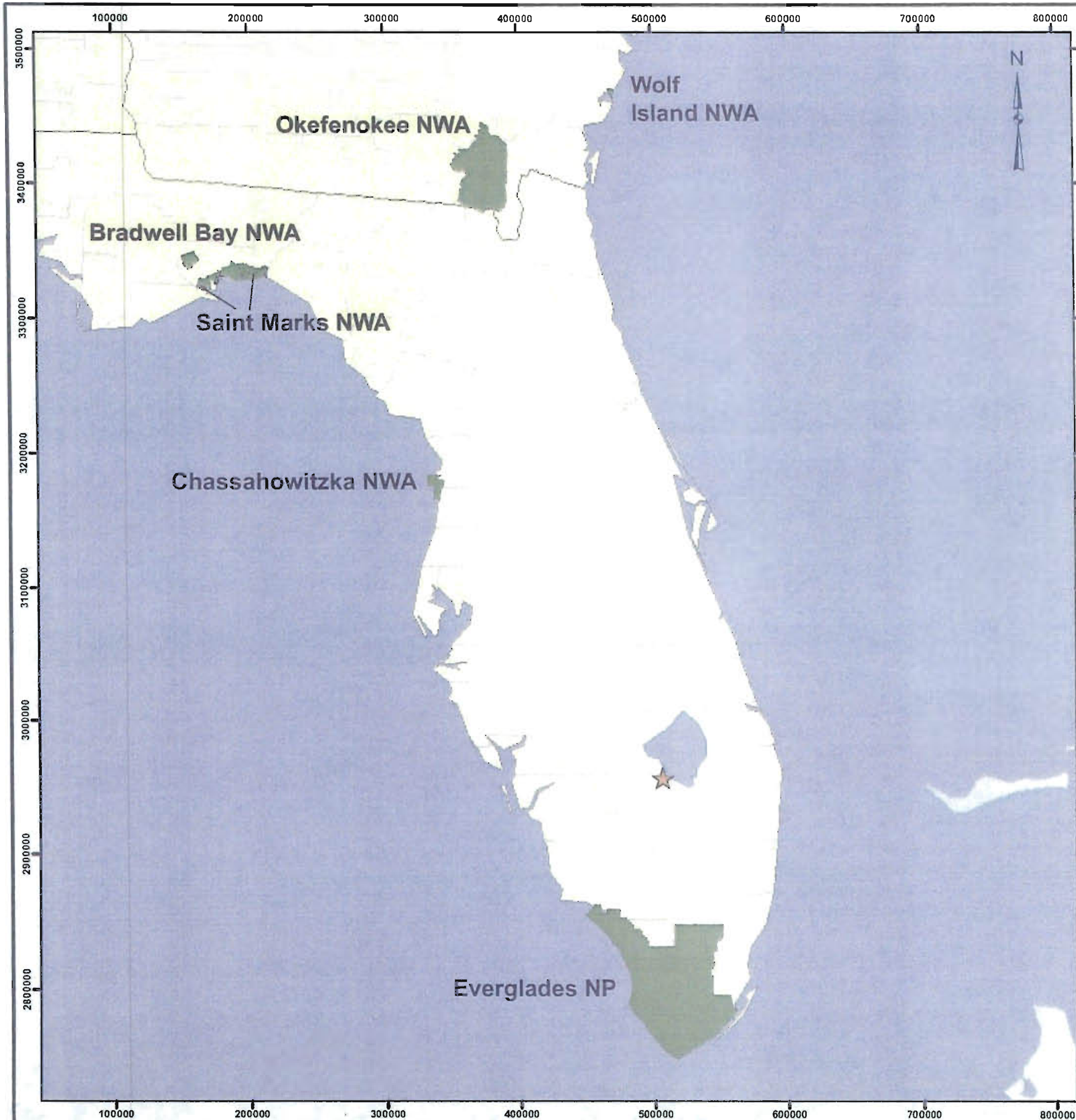
[a] Concentrations are predicted with AERMOD model and five years of surface meteorological data from the National Weather Service (NWS) station at Palm Beach International Airport and upper air soundings from the NWS station at Florida International University, Miami, 2001 to 2005.

[b] UTM Coordinates in Zone 17, NAD27 Datum

TABLE 6-7
PSD CLASS I SIGNIFICANT IMPACT ANALYSIS FOR THE PROPOSED PROJECT

Pollutant	Averaging Time	Concentration[a] (μg/m3) for Year 2001	2002	2003	Proposed EPA Class I Significant Impact Level ($\mu g/m^3$)
Nitrogen Dioxide	Annual	4.65E-05	9.14E-05	8.98E-05	0.1
	24-Hour	0.009	0.014	0.011	-
	8-Hour	0.026	0.038	0.030	-
	3-Hour	0.046	0.056	0.056	-
	1-Hour	0.066	0.102	0.064	-

[a] Based on the CALPUFF (5.711a) model and the 4-km VISTAS Domain for Florida, 2001-2003



LEGEND

Facility Location

Class I Areas

REFERENCE

Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

100,000 0 100,000 Meters

PROJECT

US SUGAR CLEWISTON
BOILER #7 PSD REPORT

TITLE

Facility Location and PSD Class I Areas

Golder Associates
Gainesville, Florida

PROJECT No. 063-7637			SCALE AS SHOWN	REV 0
DESIGN	AB	03 Apr 2007	FIGURE 6-1	
GIS	AB	03 Apr 2007		
CHECK	NV	03 Apr 2007		
REVIEW	SM	03 Apr 2007		

7.0 ADDITIONAL IMPACT ANALYSIS

7.1 Vicinity of U.S. Sugar Clewiston Mill

EPA regulations contained in 40 CFR 52.21(o) require an analysis of "additional impacts", i.e., an analysis of the impacts on soils and vegetation, growth, and impairment to visibility that would occur as a result of the project. This section presents the required analysis for the Boiler No. 7 wood chip burning project.

7.1.1 Impacts to Vegetation and Soils

The area in the vicinity of the U.S. Sugar Clewiston mill is developed and cleared of native vegetation. The primary vegetation, as well as agricultural crop, in the area of the Clewiston mill is sugarcane. Citrus groves are also located in the area, primarily to the west of Clewiston. Some vegetable farming, nurseries, and sod farms are also located in the area. According to the United States Department of Agriculture (USDA) Soil Survey of Hendry County, soils in the area are primarily histocols, which are peat soils with high amounts of organic matter.

As described in the air quality impact analysis presented in Section 6.0, the maximum predicted NO_2 concentrations as a result of the proposed project only are below the significant impact levels. Therefore, no detrimental effects on soils or vegetation should occur in this area due to the proposed project.

7.1.2 Growth Impacts

The proposed wood chip burning project will not increase employment at the U.S. Sugar Clewiston mill. Total heat input to the boiler at the mill will not increase due to the proposed project, since it is only a fuel switch. There are no new facilities, infrastructure, or support services needed for the project. As a result, no significant impacts due to associated growth are expected.

The potential impacts of NO_2 on soils, vegetation, and visibility in the ENP PSD Class I areas are addressed in the following sections.

7.2 PSD Class I Areas

This section focuses on the ecological effects of the proposed facility's impacts on AQRV, as defined under PSD regulations, in the ENP. The location of this Class I area in relation to the Clewiston mill is shown in Figure 6-1.

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 wilderness areas and bioindicators of air pollution (e.g., lichens) are also evaluated.

The predicted increase in ambient concentrations at the Class I areas due to the proposed project were presented in Table 6-7. The increase in emissions used in the modeling analysis was shown in Tables 3-3 and 6-3.

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

The relatively low sensitivity of the soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants

7.2.2 Impacts to Vegetation

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

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

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

Both short-term and long-term increases in NO_2 emissions are expected due to the project; therefore, various averaging times were modeled. By comparison of published toxicity values for NO_2 exposure to short-term and long-term (annual averaging time) modeled concentrations, the possibility of plant damage in the Class I area can be examined for acute and chronic exposure situations. For an acute exposure, the estimated 3-hour maximum NO_2 concentration due to the project only in the Class I area is 0.056 μg/m^3, based on the annual NO_2 concentration of 0.0000914 μg/m^3 and the ratio of 3-hour to annual average NO_2 concentrations from Table 6-7. This concentration is only 0.0017 to 0.0027 percent of the levels that foliar injury to sensitive in plant tissue.

For a chronic exposure, the estimated annual NO_2 concentration due to the project only at the point of maximum impact in the Class I area (0.00009 μg/m^3) is 0.000002 to 0.000005 percent of the levels that caused minimal yield loss and chlorosis in plant tissue.

In summary, the phytotoxic effects from the increase in emissions due to the proposed project are predicted to be minimal. It is important to note that the concentrations of NO_2 were conservatively modeled with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

7.2.3 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 7-1.

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

For impacts on wildlife, the lowest threshold values of NO_x reported to cause physiological changes are shown in Table 7-1. These values are up to orders of magnitude larger than the maximum predicted increase in concentrations for the Class I area. No effects on wildlife AQRVs from NO_2

are expected. These results are considered indications of the risk of other air pollutant emissions predicted from the facility.

7.2.4 Impacts on Visibility

The CAA amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Visibility can take the form of plume blight for nearby areas (i.e., distances within 50 km) or regional haze for long distances (i.e., distances beyond 50 km).

Sources of air pollution can cause visible plumes if emissions of PM_{10} and NO_x are sufficiently large. A plume will be visible if its constituents scatter or absorb sufficient light so that the plume is brighter or darker than its viewing background (e.g., the sky or a terrain feature, such as a mountain). PSD Class I areas, such as national parks and wilderness areas, are afforded special visibility protection designed to prevent plume visual impacts to observers within a Class I area.

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

Currently, there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and FLM of Class I areas that are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in guidelines required by the 1977 CAA amendments and are contained in two documents:

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

The methods and assumptions recommended in these documents were used to assess visibility impairment due to the proposed U.S. Sugar Clewiston mill project.

Based on the FLAG document, current regional haze guidelines characterize a change in visibility by the change in the light-extinction coefficient (b_{ext}). The b_{ext} is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change. An index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

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

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

The purpose of the visibility analysis is to calculate the extinction at each receptor for each day (24-hour period) of the year due to the proposed U.S. Sugar wood chip burning project emission increases only. The emissions used in the visibility analysis are the same as those shown in Table 6-3 for the proposed project. The criteria to determine whether the proposed project's impacts are potentially significant are based on a change in extinction of 5 percent or greater for any day of the year.

Processing of visibility impairment for this study was performed with the CALPUFF model and the CALPUFF post-processing program CALPOST. The analysis was conducted in accordance with the most recent guidance from the FLAG document (December 2000). The CALPUFF postprocessor model CALPOST is used to calculate the combined visibility effects from the different pollutants that are emitted from the proposed project. Daily background extinction coefficients are calculated on an hour-by-hour basis using hourly relative humidity data from CALMET and hygroscopic and non-hygroscopic extinction components specified in the FLAG document (visibility method 2). For the Class I area evaluated, the hygroscopic and non-hygroscopic components are 0.9 and 8.5 inverse mega meter (Mm^{-1}). CALPOST then predicts the percent extinction change for each day of the year.

Results

The results of the refined regional haze analysis are presented in Table 7-2. The results indicate that the proposed project's maximum predicted impact on visibility at the ENP is 0.82 percent. This value is below the FLM's screening criteria of 5 percent change. Therefore, the Boiler No. 7 wood chip burning project is not expected to have an adverse impact on the existing regional haze in the ENP.

TABLE 7-1
EXAMPLES OF REPORTED EFFECTS OF AIR POLLUTANTS 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 7-2
MAXIMUM 24-HOUR AVERAGE VISIBILITY IMPAIRMENT PREDICTED FOR THE BOILER NO. 7 PROJECT AT THE EVERGLADES NATIONAL PARK PSD CLASS I AREA

Area	Visibility Impairment (%) [a]			Visibility Impairment Criteria (%)
	2001	2002	2003	
BACKGROUND EXTINCTION CALCULATIONS: METHOD 2 WITH RHMAX = 95 PERCENT				
	0.84	0.60	0.82	5.0

[a] Concentrations are highest predicted using the VISTAS 4-km Florida Domains, 2001 to 2003.
Background extinctions calculated using FLAG Document (December 2000) and stated method

TABLE 7-3
TOTAL NITROGEN DEPOSITION RATES PREDICTED FOR THE PROPOSED PROJECT
AT THE EVERGLADES NATIONAL PARK PSD CLASS I AREA

	Total Deposition (Wet + Dry) for Year						Deposition Analysis Threshold[b]
	2001		2002		2003		
PSD Class I Area	($g/m^2/s$)	(kg/ha/yr)	($g/m^2/s$)	(kg/ha/yr)	($g/m^2/s$)	(kg/ha/yr)	(kg/ha/yr)
Everglades National Park	1.836E-13	0.00006	2.216E-13	0.00007	1.762E-13	0.00006	0.01

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

$g/m^2/s$	x	0.001	kg/g
	x	10000	m^2/hectare
	x	3600	sec/hr
	x	8760	hr/yr =kg/ha/yr
	or		
$g/m^2/s$	x	3.1536E+08	= kg/ha/yr

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

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APPENDIX A

EMISSION FACTORS

TABLE A-1
PAST ACTUAL ANNUAL (1997-2006) EMISSION FACTORS FROM ANNUAL OPERATING REPORTS FOR BOILER NO. 7, U.S. SUGAR CLEWISTON

Source Description	Annual Operation (hr/yr)	Annual Process/Fuel	Factor Units	Pollutant Emission Factors[A]							
				SO_2	NO_x	CO	PM	PM_{10}	VOC	SAM	Lead
<u>Boiler No. 7</u>											
1997 Actual Emission Factors											
--No. 2 Fuel Oil (0.05% S)	2,664	344.68 10^3 gallons	lb/1,000 gallon	7.85 [B]	20 [B]	5 [B]	0.1 [B]	0.09 [C]	0.2 [B]	0.100 [B]	1.220E-06 [B]
--Bagasse		232,559 tons Bagasse	lb/ton Bagasse	0.101 [D]	1.627 [D]	2.318 [D]	0.022 [D]	0.019 [C]	0.072 [D]	0.050 [D]	4.450E-04 [B]
1998 Actual Emission Factors											
--No. 2 Fuel Oil (0.03% S)	4,176	927.62 10^3 gallons	lb/1,000 gallon	4.71 [B]	20 [B]	5 [B]	0.1 [B]	0.09 [C]	0.2 [B]	0.100 [B]	1.220E-06 [B]
--Bagasse		299,685 tons Bagasse	lb/ton Bagasse	0.101 [D]	1.627 [D]	2.318 [D]	0.022 [D]	0.019 [C]	0.072 [D]	0.050 [D]	4.450E-04 [B]
1999 Actual Emission Factors											
--No. 2 Fuel Oil (0.05% S)	6,264	2,809.14 10^3 gallons	lb/1,000 gallon	7.85 [B]	20 [B]	5 [B]	2 [B]	1.7 [C]	0.216 [B]	0.100 [B]	1.220E-06 [B]
--Bagasse		451,741 tons Bagasse	lb/ton Bagasse	0.101 [D]	1.778 [D]	1.094 [D]	0.137 [D]	0.116 [C]	0.007 [D]	0.050 [D]	1.220E-06 [B]
2000 Actual Emission Factors											
--No. 2 Fuel Oil (0.05% S)	6,672	1,493.41 10^3 gallons	lb/1,000 gallon	7.85 [B]	24 [B]	5 [B]	2 [B]	1.7 [C]	0.2 [B]	0.285 [B]	1.510E-03 [B]
--Bagasse		522,874 tons Bagasse	lb/ton Bagasse	0.101 [D]	1.577 [D]	0.533 [D]	0.108 [D]	0.092 [C]	0.007 [D]	0.050 [D]	4.450E-04 [B]
2001 Actual Emission Factors											
--No. 2 Fuel Oil (0.05% S)	5,788	2,440.51 10^3 gallons	lb/1,000 gallon	7.85 [B]	24 [B]	5 [B]	2 [B]	1.7 [C]	0.2 [B]	0.285 [B]	1.510E-03 [B]
--Bagasse		351,558 tons Bagasse	lb/ton Bagasse	0.101 [D]	1.339 [D]	2.822 [D]	0.065 [D]	0.055 [C]	0.821 [D]	0.050 [D]	4.450E-04 [B]
2002 Actual Emission Factors											
--No. 2 Fuel Oil (0.05% S)	6,240	3,653.64 10^3 gallons	lb/1,000 gallon	7.85 [B]	24 [B]	5 [B]	2 [B]	1.7 [C]	0.2 [B]	0.285 [B]	1.220E-06 [B]
--Bagasse		381,176 tons Bagasse	lb/ton Bagasse	0.101 [D]	1.454 [D]	1.476 [D]	0.144 [D]	0.134 [E]	0.050 [D]	0.050 [D]	4.450E-04 [B]
2003 Actual Emission Factors											
--No. 2 Fuel Oil (0.05% S)	6,137	3,552.74 10^3 gallons	lb/1,000 gallon	7.85 [B]	24 [B]	5 [B]	2 [B]	1.7 [C]	0.2 [B]	0.285 [B]	1.220E-06 [B]
--Bagasse		375,958 tons Bagasse	lb/ton Bagasse	0.101 [D]	1.462 [D]	4.457 [D]	0.108 [D]	0.100 [E]	0.259 [D]	0.050 [D]	2.450E-05 [F]
2004 Actual Emission Factors											
--No. 2 Fuel Oil (0.05% S)	7,138	1,094.30 10^3 gallons	lb/1,000 gallon	7.85 [B]	24 [B]	5 [B]	2 [B]	1.7 [C]	0.2 [B]	0.285 [B]	1.220E-06 [B]
--Bagasse		435,549 tons Bagasse	lb/ton Bagasse	0.101 [D]	1.462 [D]	4.457 [D]	0.108 [D]	0.100 [E]	0.259 [D]	0.050 [D]	2.450E-05 [F]
2005 Actual Emission Factors											
--No. 2 Fuel Oil (0.0315% S)	3,909	729.57 10^3 gallons	lb/1,000 gallon	4.95 [B]	24 [B]	5 [B]	2 [B]	1.7 [C]	0.2 [B]	0.285 [B]	1.220E-06 [B]
--Bagasse		225,626 tons Bagasse	lb/ton Bagasse	0.468 [D]	1.512 [D]	1.202 [D]	0.151 [D]	0.140 [E]	0.043 [D]	0.050 [D]	2.450E-05 [F]
2006 Actual Emission Factors											
--No. 2 Fuel Oil (0.0407% S)	521	60.55 10^3 gallons	lb/1,000 gallon	6.39 [B]	24 [B]	5 [B]	2 [B]	1.7 [C]	0.2 [B]	0.284 [B]	1.220E-06 [B]
--Bagasse		36,133 tons Bagasse	lb/ton Bagasse	0.468 [D]	1.433 [D]	1.555 [D]	0.108 [D]	0.100 [E]	0.058 [D]	0.050 [D]	2.450E-05 [F]

[A] TRS, Mercury, and Fluorides are not reported in the facility Annual Operating Reports (AORs).
[B] Based on current AP-42 emission factors at the time of the AOR submittal.
[C] Assuming 85% of PM is PM_{10}.
[D] Based on compliance test data (see Table A-5).
[E] Assuming 93% of PM is PM_{10}.
[F] Based on average industry test data of 3.4E-06 lb/MMBtu or less.

TABLE A-2
REVISED EMISSION FACTORS USED TO DETERMINE PAST ACTUAL ANNUAL EMISSIONS (1997-2006) FOR BOILER NO. 7, U.S. SUGAR CLEWISTON

Source Description	Annual Operation (hr/yr)	Annual Process/Fuel	Factor Units	Pollutant Emission Factors										
				SO_2	NO_X	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluorides
<u>Boiler No. 7</u>														
1997 Actual Emission Factors														
--No. 2 Fuel Oil (0.05% S)	2,664	344.68 10^3 gallons	lb/1,000 gallon	7.10 [A]	24 [A]	5 [A]	2 [A]	1.7 [B]	0.2 [C]	- [D]	0.35 [A]	1.22E-03 [E]	4.05E-04 [E]	- [D]
--Bagasse		1,674,425 MMBtu/yr	lb/MMBtu	0.0397 [G]	0.2133 [H]	0.2460 [H]	0.0117 [H]	0.0113 [I]	0.0288 [H]	- [D]	0.0072 [J]	3.06E-05 [F]	1.18E-06 [F]	- [D]
1998 Actual Emission Factors														
--No. 2 Fuel Oil (0.03% S)	4,176	927.62 10^3 gallons	lb/1,000 gallon	4.26 [A]	24 [A]	5 [A]	2 [A]	1.7 [B]	0.2 [C]	- [D]	0.21 [A]	1.22E-03 [E]	4.05E-04 [E]	- [D]
--Bagasse		2,157,732 MMBtu/yr	lb/MMBtu	0.0397 [G]	0.2084 [H]	0.2236 [H]	0.0149 [H]	0.0145 [I]	0.0279 [H]	- [D]	0.0072 [J]	3.06E-05 [F]	1.18E-06 [F]	- [D]
1999 Actual Emission Factors														
--No. 2 Fuel Oil (0.05% S)	6,264	2,809.14 10^3 gallons	lb/1,000 gallon	7.10 [A]	24 [A]	5 [A]	2 [A]	1.7 [B]	0.2 [C]	- [D]	0.35 [A]	1.22E-03 [E]	4.05E-04 [E]	- [D]
--Bagasse		3,252,535 MMBtu/yr	lb/MMBtu	0.0397 [G]	0.1995 [H]	0.3193 [H]	0.0140 [H]	0.0136 [I]	0.0351 [H]	- [D]	0.0072 [J]	3.06E-05 [F]	1.18E-06 [F]	- [D]
2000 Actual Emission Factors														
--No. 2 Fuel Oil (0.05% S)	6,672	1,493.41 10^3 gallons	lb/1,000 gallon	7.10 [A]	24 [A]	5 [A]	2 [A]	1.7 [B]	0.2 [C]	- [D]	0.35 [A]	1.22E-03 [E]	4.05E-04 [E]	- [D]
--Bagasse		3,764,693 MMBtu/yr	lb/MMBtu	0.0397 [G]	0.2039 [H]	0.2948 [H]	0.0159 [H]	0.0154 [I]	0.0333 [H]	- [D]	0.0072 [J]	3.06E-05 [F]	1.18E-06 [F]	- [D]
2001 Actual Emission Factors														
--No. 2 Fuel Oil (0.05% S)	5,788	2,440.51 10^3 gallons	lb/1,000 gallon	7.10 [A]	24 [A]	5 [A]	2 [A]	1.7 [B]	0.2 [C]	- [D]	0.35 [A]	1.22E-03 [E]	4.05E-04 [E]	- [D]
--Bagasse		2,531,218 MMBtu/yr	lb/MMBtu	0.0397 [G]	0.1999 [H]	0.3230 [H]	0.0159 [H]	0.0155 [I]	0.0347 [H]	- [D]	0.0072 [J]	3.06E-05 [F]	1.18E-06 [F]	- [D]
2002 Actual Emission Factors														
--No. 2 Fuel Oil (0.05% S)	6,240	3,653.64 10^3 gallons	lb/1,000 gallon	7.10 [A]	24 [A]	5 [A]	2 [A]	1.7 [B]	0.2 [C]	- [D]	0.35 [A]	1.22E-03 [E]	4.05E-04 [E]	- [D]
--Bagasse		2,744,467 MMBtu/yr	lb/MMBtu	0.0397 [G]	0.2050 [H]	0.3127 [H]	0.0198 [H]	0.0193 [I]	0.0120 [H]	- [D]	0.0072 [J]	3.06E-05 [F]	1.18E-06 [F]	- [D]
2003 Actual Emission Factors														
--No. 2 Fuel Oil (0.05% S)	6,137	3,552.74 10^3 gallons	lb/1,000 gallon	7.10 [A]	24 [A]	5 [A]	2 [A]	1.7 [B]	0.2 [C]	- [D]	0.35 [A]	1.22E-03 [E]	4.05E-04 [E]	- [D]
--Bagasse		2,706,898 MMBtu/yr	lb/MMBtu	0.0397 [G]	0.2050 [H]	0.3127 [H]	0.0198 [H]	0.0193 [I]	0.0120 [H]	- [D]	0.0072 [J]	3.06E-05 [F]	1.18E-06 [F]	- [D]
2004 Actual Emission Factors														
--No. 2 Fuel Oil (0.05% S)	7,138	1,094.30 10^3 gallons	lb/1,000 gallon	7.10 [A]	24 [A]	5 [A]	2 [A]	1.7 [B]	0.2 [C]	- [D]	0.35 [A]	1.22E-03 [E]	4.05E-04 [E]	- [D]
--Bagasse		3,135,953 MMBtu/yr	lb/MMBtu	0.0397 [G]	0.2050 [H]	0.3127 [H]	0.0198 [H]	0.0193 [I]	0.0120 [H]	- [D]	0.0072 [J]	3.06E-05 [F]	1.18E-06 [F]	- [D]
2005 Actual Emission Factors														
--No. 2 Fuel Oil (0.0315% S)	3,909	729.57 10^3 gallons	lb/1,000 gallon	4.47 [A]	24 [A]	5 [A]	2 [A]	1.7 [B]	0.2 [C]	- [D]	0.22 [A]	1.22E-03 [E]	4.05E-04 [E]	- [D]
--Bagasse		1,624,507 MMBtu/yr	lb/MMBtu	0.0397 [G]	0.2050 [H]	0.3127 [H]	0.0198 [H]	0.0193 [I]	0.0120 [H]	- [D]	0.0072 [J]	3.06E-05 [F]	1.18E-06 [F]	- [D]
2006 Actual Emission Factors														
--No. 2 Fuel Oil (0.0407% S)	521	60.55 10^3 gallons	lb/1,000 gallon	5.78 [A]	24 [A]	5 [A]	2 [A]	1.7 [B]	0.2 [C]	- [D]	0.28 [A]	1.22E-03 [E]	4.05E-04 [E]	- [D]
--Bagasse		260,158 MMBtu/yr	lb/MMBtu	0.0397 [G]	0.2050 [H]	0.3127 [H]	0.0198 [H]	0.0193 [I]	0.0120 [H]	- [D]	0.0072 [J]	3.06E-05 [F]	1.18E-06 [F]	- [D]

[A] Based on AP-42 Table 1.3-1, "Criteria Pollutant Emission Factors for Fuel Oil Combustion" (9/98), No. 2 Fuel Oil, normal firing. $SO_2 = 142*S$, where S= sulfur content.
[B] Assuming 85% of PM is PM_{10} for No. 2 Fuel Oil.
[C] Based on AP-42 Table 1.3-3, "Emission Factors for Total Organic Compounds (TOC), Methan, and Nonmethane TOC (NMTOC) from Uncontrolled Fuel Oil Combustion" (9/98), Distillate oil fired.
[D] No emission factors available for fluorides and total reduced sulfur emitted from boilers combusting No. 2 fuel oil or bagasse.
[E] Based on AP-42 Table 1.3-10, "Emission Factors for Trace Elements from Distillate Fuel Oil Combustion Sources" (9/98), and 135,000 Btu/gal for No. 2 Fuel Oil.
[F] Based on average value from laboratory fuel analysis.
[G] Based on average of stack tests performed 11/18/1997 and 2/4/2005. See Table A-5.
[H] Five year average emission value from stack testing. See Table A-5.
[I] Based on AP-42 Table 1.8-1, "Emission Factors for Bagasse-Fired Boilers" (9/98), where PM_{10} is shown to be approximately 97.1% of PM.
[J] Based on stack test performed 11/18/1997. See Table A-5.

TABLE A-3
BASELINE ACTUAL EMISSIONS FROM BOILER NO. 7, U.S. SUGAR CLEWISTON

Source Description	Pollutant Emission Rate (TPY) [a]									
	SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluorides
Boiler No. 7											
1997 Actual Emissions											
--No. 2 Fuel Oil	1.22	4.14	0.86	0.34	0.29	0.03	-	0.06	2.09E-04	6.98E-05	-
--Bagasse	33.20	178.61	205.98	9.77	9.49	24.10	-	5.99	2.56E-02	9.88E-04	-
--Total	***34.43***	***182.75***	***206.85***	***10.11***	***9.78***	***24.13***	-	***6.05***	***2.58E-02***	***1.06E-03***	-
1998 Actual Emissions											
--No. 2 Fuel Oil	1.98	11.13	2.32	0.93	0.79	0.09	-	0.10	5.64E-04	1.88E-04	-
--Bagasse	42.79	224.79	241.23	16.12	15.66	30.08	-	7.71	3.30E-02	1.27E-03	-
--Total	***44.76***	***235.92***	***243.55***	***17.05***	***16.45***	***30.17***	-	***7.81***	***3.36E-02***	***1.46E-03***	-
1999 Actual Emissions											
--No. 2 Fuel Oil	9.97	33.71	7.02	2.81	2.39	0.28	-	0.49	1.71E-03	5.69E-04	-
--Bagasse	64.49	324.48	519.19	22.74	22.09	57.01	-	11.63	4.98E-02	1.92E-03	-
--Total	***74.47***	***358.19***	***526.21***	***25.55***	***24.48***	***57.29***	-	***12.12***	***5.15E-02***	***2.49E-03***	-
2000 Actual Emissions											
--No. 2 Fuel Oil	5.30	17.92	3.73	1.49	1.27	0.15	-	0.26	9.07E-04	3.02E-04	-
--Bagasse	74.65	383.74	554.89	29.90	29.04	62.65	-	13.46	5.76E-02	2.22E-03	-
--Total	***79.95***	***401.66***	***558.62***	***31.39***	***30.31***	***62.79***	-	***13.72***	***5.85E-02***	***2.52E-03***	-
2001 Actual Emissions											
--No. 2 Fuel Oil	8.66	29.29	6.10	2.44	2.07	0.24	-	0.43	1.48E-03	4.94E-04	-
--Bagasse	50.19	252.98	408.84	20.18	19.61	43.89	-	9.05	3.87E-02	1.49E-03	-
--Total	***58.85***	***282.26***	***414.94***	***22.62***	***21.68***	***44.14***	-	***9.48***	***4.02E-02***	***1.99E-03***	-
2002 Actual Emissions											
--No. 2 Fuel Oil	12.97	43.84	9.13	3.65	3.11	0.37	-	0.64	2.22E-03	7.40E-04	-
--Bagasse	54.42	281.30	429.09	27.24	26.46	16.50	-	9.81	4.20E-02	1.62E-03	-
--Total	***67.39***	***325.14***	***438.22***	***30.89***	***29.57***	***16.86***	-	***10.45***	***4.42E-02***	***2.36E-03***	-
2003 Actual Emissions											
--No. 2 Fuel Oil	12.61	42.63	8.88	3.55	3.02	0.36	-	0.62	2.16E-03	7.19E-04	-
--Bagasse	53.67	277.45	423.21	26.86	26.10	16.27	-	9.68	4.14E-02	1.60E-03	-
--Total	***66.29***	***320.08***	***432.09***	***30.42***	***29.12***	***16.63***	-	***10.30***	***4.36E-02***	***2.32E-03***	-
2004 Actual Emissions											
--No. 2 Fuel Oil	3.88	13.13	2.74	1.09	0.93	0.11	-	0.19	6.65E-04	2.22E-04	-
--Bagasse	62.18	321.42	490.29	31.12	30.23	18.85	-	11.21	4.80E-02	1.85E-03	-
--Total	***66.07***	***334.56***	***493.03***	***32.22***	***31.16***	***18.96***	-	***11.40***	***4.86E-02***	***2.07E-03***	-
2005 Actual Emissions											
--No. 2 Fuel Oil	1.63	8.75	1.82	0.73	0.62	0.07	-	0.08	4.43E-04	1.48E-04	-
--Bagasse	32.21	166.51	253.99	16.12	15.66	9.77	-	5.81	2.49E-02	9.58E-04	-
--Total	***33.84***	***175.26***	***255.81***	***16.85***	***16.28***	***9.84***	-	***5.89***	***2.53E-02***	***1.11E-03***	-
2006 Actual Emissions											
--No. 2 Fuel Oil	0.17	0.73	0.15	0.06	0.05	0.01	-	0.01	3.68E-05	1.23E-05	-
--Bagasse	5.16	26.67	40.67	2.58	2.51	1.56	-	0.93	3.98E-03	1.53E-04	-
--Total	***5.33***	***27.39***	***40.83***	***2.64***	***2.56***	***1.57***	-	***0.94***	***4.02E-03***	***1.66E-04***	-

TPY = Tons per year.

Notes:
[a] See Table A-2 for emission factors and operating data.

TABLE A-4
SUMMARY OF BASELINE 2-YEAR AVERAGE ACTUAL EMISSIONS FROM BOILER NO. 7, U.S. SUGAR CLEWISTON

Source Description	Pollutant Emission Rate (TPY) [a]										
	SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluorides
Boiler No. 7											
1997 - 1998 Average Emissions	39.59	209.33	225.20	13.58	13.11	27.15	-	6.93	0.03	0.0013	-
1998 - 1999 Average Emissions	59.61	297.05	384.88	21.30	20.46	43.73	-	9.97	0.04	0.0020	-
1999 - 2000 Average Emissions	77.21	379.92	542.42	28.47	27.39	60.04	-	12.92	0.05	0.0025	-
2000 - 2001 Average Emissions	69.40	341.96	486.78	27.01	26.00	53.47	-	11.60	0.05	0.0023	-
2001 - 2002 Average Emissions	63.12	303.70	426.58	26.76	25.62	30.50	-	9.96	0.04	0.0022	-
2002 - 2003 Average Emissions	66.84	322.61	435.16	30.65	29.34	16.75	-	10.37	0.04	0.0023	-
2003 - 2004 Average Emissions	66.18	327.32	462.56	31.32	30.14	17.79	-	10.85	0.05	0.0022	-
2004 - 2005 Average Emissions	49.96	254.91	374.42	24.53	23.72	14.40	-	8.65	0.04	0.0016	-
2005 - 2006 Average Emissions	19.59	101.33	148.32	9.75	9.42	5.70	-	3.41	0.01	0.0006	-
Average Actual Emissions of Highest 2-Year Period	'99-'00	'99-'00	'99-'00	'03-'04	'03-'04	'99-'00	--	'99-'00	'99-'00	'99-'00	--
--*Total*	**77.21**	**379.92**	**542.42**	**31.32**	**30.14**	**60.04**	-	**12.92**	**0.05**	**0.0025**	-

TPY = Tons per year.

Notes:
[a] See Table A-2 for emission factors.

TABLE A-5
EMISSIONS AND PLANT OPERATING DATA FOR BOILER NO. 7 STACK TESTS

Test Date	Crop Season	Steam Production (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate (TPH)	PM			CO			NO_X			VOC			SAM		SO_2	
					Emission Rate (lb/MMBtu)	Averaging Period	Avg. Rate (lb/MMBtu)	Emission Rate (lb/MMBtu)	Averaging Period	Avg. Rate (lb/MMBtu)	Emission Rate (lb/MMBtu)	Averaging Period	Avg. Rate (lb/MMBtu)	Emission Rate (lb/MMBtu)	Averaging Period	Avg. Rate (lb/MMBtu)	Emission Rate (lb/MMBtu)	Avg. Rate (lb/MMBtu)	Emission Rate (lb/MMBtu)	Avg. Rate (lb/MMBtu)
Bagasse Firing																				
11/17/1997	1997-1998	348,373	727.67	101.06	0.0032	1997-2001	0.0117	0.3210	1997-2001	0.2460	0.2264	1997-2001	0.2133	0.0118	1997-2001	0.0288	0.0072	0.0072	--	0.0397
11/18/1997	1997-1998	356,538	743.33	103.24	--			--			--			--			--		0.0140	
2/8/1999	1998-1999	354,719	725.97	100.83	0.0192	1998-2002	0.0149	0.1520	1998-2002	0.2236	0.2466	1998-2002	0.2084	0.0007	1998-2002	0.0279	--	0.0072	--	0.0397
12/17/1999	1999-2000	364,345	751.65	104.40	0.0121	1999-2003	0.0140	0.2897	1999-2003	0.3193	0.1888	1999-2003	0.1995	0.0154	1999-2003	0.0351	--	0.0072	--	0.0397
1/5/2001	2000-2001	327,500	666.22	92.53	0.0150	2000-2004	0.0159	0.0745	2000-2004	0.2948	0.2187	2000-2004	0.2039	0.0011	2000-2004	0.0333	--	0.0072	--	0.0397
1/9/2002	2001-2002	329,896	702.32	97.55	0.0088	2001-2005	0.0159	0.3931	2001-2005	0.3230	0.1861	2001-2005	0.1999	0.1150	2001-2005	0.0347	--	0.0072	--	0.0397
11/15/2002	2002-2003	347,199	736.65	102.31	0.0196	2002-2006	0.0198	0.2088	2002-2006	0.3127	0.2015	2002-2006	0.2050	0.0073	2002-2006	0.0120	--	0.0072	--	0.0397
12/30/2003	2003-2004	340,888	713.52	99.10	0.0144	2002-2006	0.0198	0.6303	2002-2006	0.3127	0.2025	2002-2006	0.2050	0.0365	2002-2006	0.0120	--	0.0072	--	0.0397
2/4/2005	2004-2005	227,758	485.88	67.48	0.0216	2002-2006	0.0198	0.1674	2002-2006	0.3127	0.2105	2002-2006	0.2050	0.0065	2002-2006	0.0120	--	0.0072	0.0653	0.0397
1/5/2006	2005-2006	338,728	700.63	97.31	0.0153	2002-2006	0.0198	0.2157	2002-2006	0.3127	0.1988	2002-2006	0.2050	0.0080	2002-2006	0.0120	--	0.0072	--	0.0397
1/25/2007	2006-2007	305,754	631.59	87.72	0.0283	2002-2006	0.0198	0.3413	2002-2006	0.3127	0.2117	2002-2006	0.2050	0.0017	2002-2006	0.0120	--	0.0072	--	0.0397
Average =		331,063	689.58	95.78																
Maximum =		364,345	751.65	104.40																
Minimum =		227,758	485.88	67.48																
75% Bagasse, 25% Wood Chips Firing																				
5/3/2005	2005	221,935	459.03	--	--	--	--	0.1763	--	0.1763	0.3110	--	0.3110	--	--	--	--	--	--	--

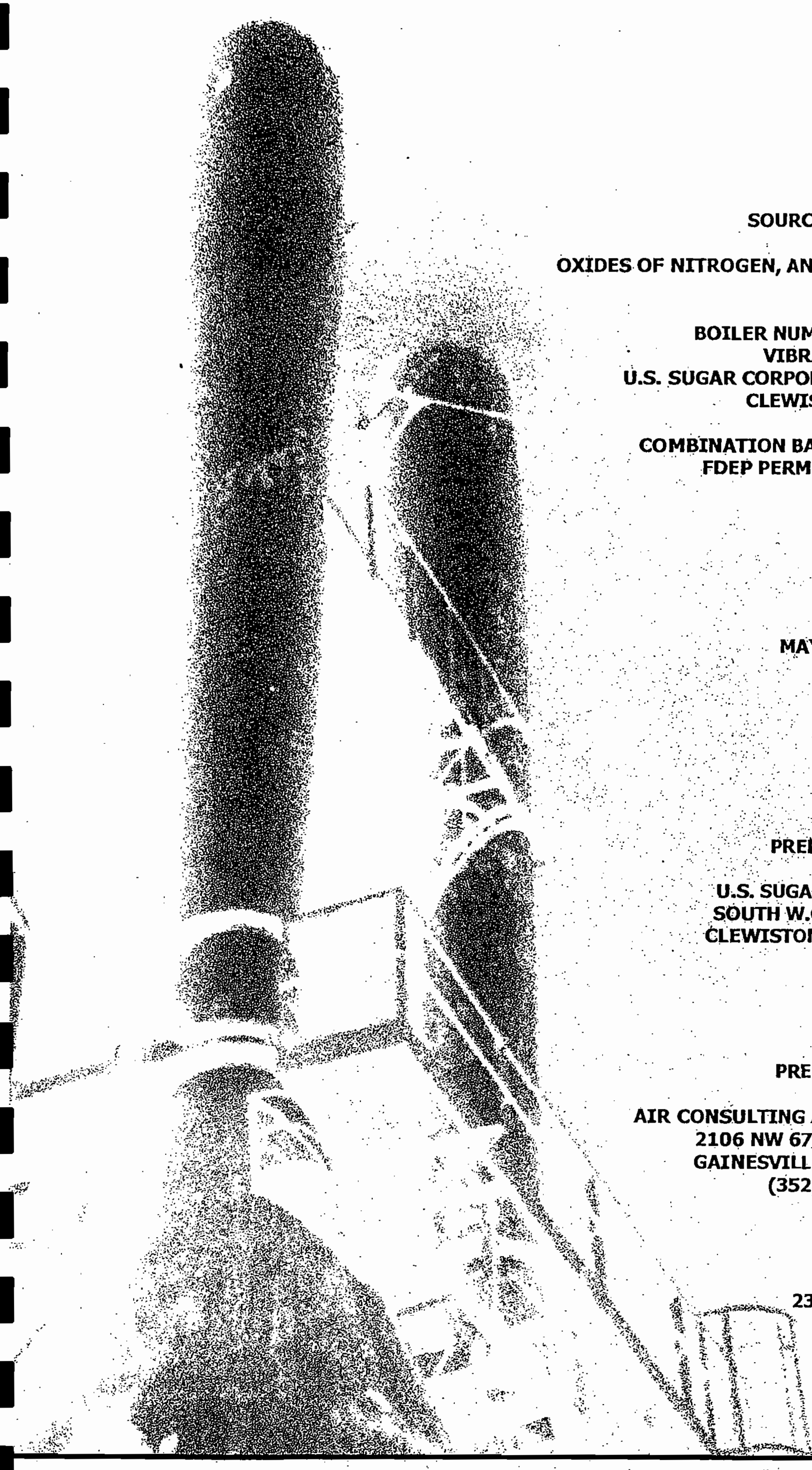
TABLE A-6
PAST ACTUAL OPERATING CONDITIONS OF BOILER NO. 7

		Fuel Usage						2-Year Average				Percent of Total Heat Input	
	Plant Operation	No. 2 Fuel Oil	Bagasse	Heat Input Rate (MMBtu/yr)[a]			2-Year	Plant Operation	Heat Input Rate (MMBtu/yr)				
Year	(hours)	(10^3 gallons/yr)	(tons/yr)	Fuel Oil	Bagasse	Total	Period	(hours)	Fuel Oil	Bagasse	Total	Fuel Oil	Bagasse
1997	2,664	344.68	232,559	46,532	1,674,425	1,720,957	--	--	--	--	--		
1998	4,176	927.62	299,685	125,228	2,157,732	2,282,960	1997 - 1998	3,420	85,880	1,916,078	2,001,959	4.3%	95.7%
1999	6,264	2,809.14	451,741	379,234	3,252,535	3,631,769	1998 - 1999	5,220	252,231	2,705,134	2,957,365	8.5%	91.5%
2000	6,672	1,493.41	522,874	201,610	3,764,693	3,966,303	1999 - 2000	6,468	290,422	3,508,614	3,799,036	7.6%	92.4%
2001	5,788	2,440.51	351,558	329,469	2,531,218	2,860,686	2000 - 2001	6,230	265,540	3,147,955	3,413,495	7.8%	92.2%
2002	6,240	3,653.64	381,176	493,241	2,744,467	3,237,709	2001 - 2002	6,014	411,355	2,637,842	3,049,198	13.5%	86.5%
2003	6,137	3,552.74	375,958	479,620	2,706,898	3,186,518	2002 - 2003	6,189	486,431	2,725,682	3,212,113	15.1%	84.9%
2004	7,138	1,094.30	435,549	147,731	3,135,953	3,283,683	2003 - 2004	6,638	313,675	2,921,425	3,235,100	9.7%	90.3%
2005	3,909	729.57	225,626	98,492	1,624,507	1,722,999	2004 - 2005	5,524	123,111	2,380,230	2,503,341	4.9%	95.1%
2006	521	60.55	36,133	8,174	260,158	268,332	2005 - 2006	2,215	53,333	942,332	995,666	5.4%	94.6%
							Average Actual Operating Conditions of Highest 2-Year Period						
								'03 - '04	**'02 - '03**	**'99 - '00**	**'99 - '00**		
								6,638	**486,431**	**3,508,614**	**3,799,036**		

[a] Heat input rates based on 135,000 Btu/gal for No. 2 fuel oil, and 3,600 Btu/lb for bagasse. See Table A-1 for fuel usage amounts.

APPENDIX B

EXCERPTS FROM BOILER NO. 7 TESTING ON WOOD CHIPS



SOURCE TEST REPORT
FOR
OXIDES OF NITROGEN, AND CARBON MONOXIDE EMISSIONS

BOILER NUMBER 7 – ESP OUTLET
VIBRATING GRATE
U.S. SUGAR CORPORATION – CLEWISTON MILL
CLEWISTON, FLORIDA

COMBINATION BAGASSE AND WOOD CHIPS
FDEP PERMIT 0510003-028-AC

MAY 3-5, 2005

PREPARED FOR:

U.S. SUGAR CORPORATION
SOUTH W.C. OWEN AVENUE
CLEWISTON, FLORIDA 33440

PREPARED BY:

AIR CONSULTING AND ENGINEERING, INC.
2106 NW 67TH PLACE, SUITE 4
GAINESVILLE, FLORIDA 32653
(352) 335-1889

238-04-03

2.0 SUMMARY AND DISCUSSION OF RESULTS

Table 1 is a summary of the emission results and flue gas parameters.

A combination of Bagasse and Wood Chips were used to fire the boiler.

Oxides of nitrogen emissions were 0.318, 0.314 and 0301 lbs/MMBTU while the boiler was fired with a fuel mixture of 15% Wood Chips and 45% Bagasse. Firing with Bagasse alone resulted NO_x emissions of 0.249 lbs/MMBTU. The permitted NOx limit for the boiler is 0.25 lbs/MMBTU.

Carbon monoxide emissions were 0.139, 0.246 and 0.144 lbs/MMBTU while fired with the fuel mixture and 0.245 lbs/MMBTU while fired with Bagasse alone. The permitted CO limit is 0.7 lbs/MMBTU.

Volumetric flow data, emission summaries and strip chart copies and data logger records are presented in Appendices A, B and C.

Production rate summaries are provided in Appendix D. This data was obtained from control room recordings of steam flow, temperature, and pressure as well as feed water temperature and pressure. Steam integrator readings were recorded at the beginning and at the end of the each particulate run.

Table 1. Emission Summary
Boiler 7 - ESP Outlet
United States Sugar Corporation - Clewiston Mill
Clewiston, Florida
May 3-5, 2005

Run Number	Date	Time	Fuel	Steam Rate	Heat Input	CO_2	Oxygen	Flow Rate	CO Emissions		NOx Emissions	
				lbs/hr	MMBTUH	%	%	dscfm	lbs/MMBTU	lbs/hr	lbs/MMBTU	lbs/hr
1	5/3/05	1323-1423	25% Wood Chip/ 75% Bagasse	242727	502.1	10.9	10.4	162497	0.139	69.93	0.318	159.50
2	5/3/05	1437-1537	25% Wood Chip/ 75% Bagasse	227077	468.0	10.1	10.9	164363	0.246	115.32	0.314	147.01
3	5/4/05	1136-1236	100% Bagasse	193125	401.8	9.4	11.2	153399	0.245	98.43	0.249	100.05
4	5/5/05	1440-1540		Run aborted - lack of Wood Chips in fuel mixture								
5	5/5/05	1701-1801	25% Wood Chip/ 75% Bagasse	196000	407.0	9.0	11.4	160047	0.144	58.79	0.301	122.57

Fuel Percentages were calculated from belt speeds. 15% wood chips/45% bagasse belt speeds would correspond to a 25%wood chip/75%bagasse fuel mixture

Heat Input calculations are based on steam parameters and a boiler efficiency of 55%

3.0 PROCESS DESCRIPTION AND OPERATION

The Number 7 Boiler at US Sugar Corporation's Clewiston facility is a vibrating grate unit. The heat input is rated at 812 million BTU per hour (MMBTUH) on an 1-hour average and 738 MMBTUH on a 24-hour average, with a steam production of 385,000 pounds per hour (lbs/hr) based on the 1-hour average and 350,000 lbs/hr based on the 24-hour average heat input. The steam is used to produce electricity as well as steam for the A & B train sugar mills, which in turn produce bagasse fuel to fire the boiler(s).

The Number 7 Boiler is also capable of firing Number 2 fuel oil for start-up periods and as supplemental fuel if the bagasse fuel feed is insufficient. During this test series, the boiler was fired with a mixture of 25% Wood Chips and 75% Bagasse. The fuel percentages are based on belt speed. Full speed was identical for both belts. The belt conveying the wood chips was operating at 15% of its full speed while the bagasse conveyer belt was operated at 45% of full speed. Fuel analysis and boiler operating parameters are presented in Appendix D.

Particulate emissions are controlled by a wet bottom cyclone dust collector followed by an electrostatic precipitator (ESP). The cyclone removes sand and partially combusted bagasse fibers to protect the induced draft fan and ESP.

Table 1. Proximate, Ultimate, and Heat Content Analyses Results for Wood Fuel, U.S. Sugar Clewiston

Parameter	Units	Analysis Results (dry basis) for Sample Weeks (collection dates)									
		2/23/2005	3/17/2005	4/15/2005	4/27/2005	5/3/2005	4/25/05 - 5/6/05	5/10/2005	5/13/05 - 5/20/05	5/19/2005	6/8/2005
		Composit e	Composite Wks 1-2	Composite WPB Wks 1-2	Composite WPB A Week 3	Southeastern Composite Week 2	Southeastern Composite	BLT Test #7 Nox	Southeastern Composite	SE Organic	D.J. Casey
No. of Samples Composited		6	6	6	6	6	6	6	6	6	6
Moisture	%, as received	26.44	32.27	26.93	27.54	34.08	31.94	32.89	34.18	34.09	35.87
Ash	%, as received	2.01	4.36	12.22	5.33	11.14	18.08	30.67	25.72	22.24	21.93
Ash	%, dry	2.74	6.43	16.72	7.35	16.90	26.57	45.70	39.08	33.74	34.19
HHV	Btu/lb, as receivec	6,154	5,443	5,719	5,797	4,870	4,362	3,160	3,418	3,779	3,463
HHV	Btu/lb, dry	8,366	8,037	7,827	8,000	7,387	6,410	4,709	5,193	5,734	5,400
Air Dry Loss	%	22.61	31.20	25.21	26.21	31.99	29.73	28.29	29.68	31.55	31.56
Arsenic	ppm, dry	<10	1.7	9.5	9.1	1.0	0.9	0.6	1.3	1.0	ND
Chromium	ppm, dry	<0.4	5.7	17	40	<1	10	9	<8	<7	ND
Copper	ppm, dry	5.4	12	52.7	38	<10	13	27	17	12	ND

Note: % = percent.
Btu/lb = British thermal unit per pound.
HHV = higher heating value.
lb/MMBtu = pounds per million British thermal unit.

AIR CONSULTING and ENGINEERING, INC.
BOILER PARAMETERS and HEAT INPUT CALCULATIONS

COMPANY NAME:	U.S.S.C.
LOCATION:	CLEWISTON, FLORIDA
SOURCE:	BOILER 7
DATE:	5/3/05
RUN NUMBER:	1

BEGIN INTEGRATOR TIME:	1:23 PM
END INTERGRATOR TIME:	2:29 PM
TOTAL TIME:	1:06
TOTAL MINUTES:	66
OIL METER INITIAL READING:	0
OIL METER FINAL READING:	0
OIL METER FACTOR:	1
OIL USAGE (gph)	0
STEAM INTEGRATOR INITIAL READING:	1723
STEAM INTEGRATOR FINAL READING:	1990
STEAM INTEGRATOR FACTOR:	1000
STEAM RATE (lbs/Hr)	242727
FEEDWATER:	
TEMPERATURE (F):	251.0
PRESSURE (psia):	1277.3
ENTHALPY (BTU/lb):	222.1
STEAM:	
TEMPERATURE (F):	719.2
PRESSURE (psia):	637.5
ENTHALPY (BTU/lb):	1359.9
BOILER EFFICIENCY (percent):	55.0
HEAT INPUT:	
NET STEAM (MMBTU/Hr):	502.1
HEAT INPUT FROM OIL @ 150000 BTU/gal (MMBTU/Hr):	0.0
HEAT INPUT FROM NON-OIL (MMBTU/Hr):	502.1
ALLOWABLE PM EMISSION FROM OIL (lb/MMBTU):	0.10
ALLOWABLE PM EMISSION FROM NON-OIL (lb/MMBTU):	0.15
TOTAL ALLOWABLE PM EMISSION (lb/Hr):	75.32
TOTAL ALLOWABLE PM EMISSION (lb/MMBTU):	0.15

AIR CONSULTING and ENGINEERING, INC.
BOILER PARAMETERS and HEAT INPUT CALCULATIONS

COMPANY NAME: U.S.S.C.
LOCATION: CLEWISTON, FLORIDA
SOURCE: BOILER 7
DATE: 5/3/2005
RUN NUMBER: 2

BEGIN INTEGRATOR TIME:	2:37 PM
END INTERGRATOR TIME:	3:42 PM
TOTAL TIME:	1:05
TOTAL MINUTES:	65
OIL METER INITIAL READING:	0
OIL METER FINAL READING:	0
OIL METER FACTOR:	1
OIL USAGE (gph)	0
STEAM INTEGRATOR INITIAL READING:	2023
STEAM INTEGRATOR FINAL READING:	2269
STEAM INTEGRATOR FACTOR:	1000
STEAM RATE (lbs/Hr)	227077
FEEDWATER:	
TEMPERATURE (F):	248.8
PRESSURE (psia):	1293.5
ENTHALPY (BTU/lb):	219.9
STEAM:	
TEMPERATURE (F):	708.0
PRESSURE (psia):	630.5
ENTHALPY (BTU/lb):	1353.5
BOILER EFFICIENCY (percent):	55.0
HEAT INPUT:	
NET STEAM (MMBTU/Hr):	468.0
HEAT INPUT FROM OIL @ 150000 BTU/gal (MMBTU/Hr):	0.0
HEAT INPUT FROM NON-OIL (MMBTU/Hr):	468.0
ALLOWABLE PM EMISSION FROM OIL (lb/MMBTU):	0.10
ALLOWABLE PM EMISSION FROM NON-OIL (lb/MMBTU):	0.15
TOTAL ALLOWABLE PM EMISSION (lb/Hr):	70.21
TOTAL ALLOWABLE PM EMISSION (lb/MMBTU):	0.15

AIR CONSULTING and ENGINEERING, INC.
BOILER PARAMETERS and HEAT INPUT CALCULATIONS

COMPANY NAME: U.S.S.C.
LOCATION: CLEWISTON, FLORIDA
SOURCE: BOILER 7
DATE: 5/4/05
RUN NUMBER: 1, 3

BEGIN INTEGRATOR TIME:	11:36 AM
END INTERGRATOR TIME:	12:40 PM
TOTAL TIME:	1:04
TOTAL MINUTES:	64
OIL METER INITIAL READING:	0
OIL METER FINAL READING:	0
OIL METER FACTOR:	1
OIL USAGE (gph)	0
STEAM INTEGRATOR INITIAL READING:	6099
STEAM INTEGRATOR FINAL READING:	6305
STEAM INTEGRATOR FACTOR:	1000
STEAM RATE (lbs/Hr)	193125
FEEDWATER:	
TEMPERATURE (F):	250.0
PRESSURE (psia):	1303.7
ENTHALPY (BTU/lb):	221.2
STEAM:	
TEMPERATURE (F):	724.3
PRESSURE (psia):	593.0
ENTHALPY (BTU/lb):	1365.5
BOILER EFFICIENCY (percent):	55.0
HEAT INPUT:	
NET STEAM (MMBTU/Hr):	401.8
HEAT INPUT FROM OIL @ 150000 BTU/gal (MMBTU/Hr):	0.0
HEAT INPUT FROM NON-OIL (MMBTU/Hr):	401.8
ALLOWABLE PM EMISSION FROM OIL (lb/MMBTU):	0.10
ALLOWABLE PM EMISSION FROM NON-OIL (lb/MMBTU):	0.15
TOTAL ALLOWABLE PM EMISSION (lb/Hr):	60.27
TOTAL ALLOWABLE PM EMISSION (lb/MMBTU):	0.15

AIR CONSULTING and ENGINEERING, INC.
BOILER PARAMETERS and HEAT INPUT CALCULATIONS

COMPANY NAME: U.S.S.C.
LOCATION: CLEWISTON, FLORIDA
SOURCE: BOILER 7
DATE: 5/5/05
RUN NUMBER: 4 **RUN ABORTED**

BEGIN INTEGRATOR TIME:	11:36 AM
END INTERGRATOR TIME:	12:40 PM
TOTAL TIME:	1:04
TOTAL MINUTES:	64
OIL METER INITIAL READING:	0
OIL METER FINAL READING:	0
OIL METER FACTOR:	1
OIL USAGE (gph)	0
STEAM INTEGRATOR INITIAL READING:	6099
STEAM INTEGRATOR FINAL READING:	6305
STEAM INTEGRATOR FACTOR:	1000
STEAM RATE (lbs/Hr)	193125
FEEDWATER:	
TEMPERATURE (F):	250.0
PRESSURE (psia):	1303.7
ENTHALPY (BTU/lb):	221.2
STEAM:	
TEMPERATURE (F):	724.3
PRESSURE (psia):	593.0
ENTHALPY (BTU/lb):	1365.5
BOILER EFFICIENCY (percent):	55.0
HEAT INPUT:	
NET STEAM (MMBTU/Hr):	401.8
HEAT INPUT FROM OIL @ 150000 BTU/gal (MMBTU/Hr):	0.0
HEAT INPUT FROM NON-OIL (MMBTU/Hr):	401.8
ALLOWABLE PM EMISSION FROM OIL (lb/MMBTU):	0.10
ALLOWABLE PM EMISSION FROM NON-OIL (lb/MMBTU):	0.15
TOTAL ALLOWABLE PM EMISSION (lb/Hr):	60.27
TOTAL ALLOWABLE PM EMISSION (lb/MMBTU):	0.15

AIR CONSULTING and ENGINEERING, INC.
BOILER PARAMETERS and HEAT INPUT CALCULATIONS

COMPANY NAME:	U.S.S.C.	15% WOOD CHIPS 45% BAGASSE
LOCATION:	CLEWISTON, FLORIDA	
SOURCE:	BOILER 7	
DATE:	5/5/2005	
RUN NUMBER:	5	

BEGIN INTEGRATOR TIME:	5:01 PM
END INTERGRATOR TIME:	6:01 PM
TOTAL TIME:	1:00
TOTAL MINUTES:	60
OIL METER INITIAL READING:	0
OIL METER FINAL READING:	0
OIL METER FACTOR:	1
OIL USAGE (gph)	0
STEAM INTEGRATOR INITIAL READING:	1470
STEAM INTEGRATOR FINAL READING:	1666
STEAM INTEGRATOR FACTOR:	1000
STEAM RATE (lbs/Hr)	196000
FEEDWATER:	
TEMPERATURE (F):	250.0
PRESSURE (psia):	1307.5
ENTHALPY (BTU/lb):	221.2
STEAM:	
TEMPERATURE (F):	717.8
PRESSURE (psia):	568.7
ENTHALPY (BTU/lb):	1363.1
BOILER EFFICIENCY (percent):	55.0
HEAT INPUT:	
NET STEAM (MMBTU/Hr):	406.9
HEAT INPUT FROM OIL @ 150000 BTU/gal (MMBTU/Hr):	0.0
HEAT INPUT FROM NON-OIL (MMBTU/Hr):	406.9
ALLOWABLE PM EMISSION FROM OIL (lb/MMBTU):	0.10
ALLOWABLE PM EMISSION FROM NON-OIL (lb/MMBTU):	0.15
TOTAL ALLOWABLE PM EMISSION (lb/Hr):	61.04
TOTAL ALLOWABLE PM EMISSION (lb/MMBTU):	0.15

AIR CONSULTING and ENGINEERING, INC.
COMPLETE EMISSION DATA

COMPANY NAME:	U.S.S.C.	15% WOOD CHIPS 45% BAGASSE
LOCATION:	CLEWISTON, FLORIDA	
SOURCE:	BOILER 7	
DATE:	5/5/05	

RUN WAS ABORTED LACK OF WOOD CHIPS IN FUEL MIXTUR

RUN NUMBER:	4		IMPINGER ml.	0.0
BEGIN TIME (hour : minute):	2:40 PM		SILICA GEL. gms.	0.0
END TIME (hour : minute):	3:40 PM		% O2:	0.00
TOTAL RUN TIME:	60	MINUTES	% CO2:	0.00
BAROMETRIC PRESSURE:	30.03	inches Hg.	"F" FACTOR:	NA
STACK PRESSURE:	29.48	inches Hg.		
NOZZLE DIAMETER:	NA	INCHES		
METER CORR. FACTOR:	0.997			
FINAL METER:	0.000	CUBIC FT.		
INITIAL METER:	0.000	CUBIC FT.		
STACK AREA:	85.573	SQ. FT.		
PITOT Cp:	0.84			

EMISSION RESULTS

NOZZLE AREA (SQ. FT.):	NA	VOLUMETRIC FLOW(ACFM):	#DIV/0!
AVG. SQ. RT. VEL. HEAD:	0.8221	VOLUMETRIC FLOW(WVSCFM):	#DIV/0!
AVG. VEL. HEAD (in H2O):	0.6800	VOLUMETRIC FLOW(DSCFM):	#DIV/0!
AVG. STACK TEMP. (F):	379.6	**STEAM RATE (LB/Hr):**	**193125**
AVG. METER TEMP. (F):	71.2		
AVG. ORIFICE DIFFERENTIAL:	1.600	**PARTICULATE EMISSION RATE:**	
METER ACF:	0	**POUNDS PER HOUR:**	**#VALUE!**
METER SCF:	0.000	**POUNDS PER MMBTU:**	**#VALUE!**
MEASURED SCF MOISTURE:	0.000		
MEASURED MOISTURE %:	#DIV/0!	**ALLOWABLE EMISSION RATE:**	
STACK TEMP. (deg. C):	193.1	**POUNDS PER HOUR:**	**60.27**
VAPOR PRESSURE:	391.0	**POUNDS PER MMBTU:**	**0.150**
SATURATION MOISTURE %:	NA		
PERCENT WATER VAPOR:	#DIV/0!		
GAS MOLECULAR WT.(dry):	28.00		
GAS MOLECULAR WT.(wet):	#DIV/0!		
PERCENT EXCESS AIR:	NA		
AVERAGE VELOCITY(FPS):	#DIV/0!		
MMBTUH(if applicable):	**401.82**		
PERCENT ISOKINETIC:	NA		

NOTE: O2 & CO2 VALUES FICTICIOUS FOR USE OF 30 AS MOLECULAR WT.

AIR CONSULTING and ENGINEERING, INC.
COMPLETE EMISSION DATA

COMPANY NAME:	U.S.S.C.	**15% WOOD CHIPS 45% BAGASSE**		
LOCATION:	CLEWISTON, FLORIDA			
SOURCE:	BOILER 7			
DATE:	5/5/2005			

RUN NUMBER:	5		IMPINGER ml.	78.0
BEGIN TIME (hour : minute):	5:01 PM		SILICA GEL. gms.	7.0
END TIME (hour : minute):	6:01 PM		% O2:	11.42
TOTAL RUN TIME:	60	MINUTES	% CO2:	9.04
BAROMETRIC PRESSURE:	30.03	inches Hg.	"F" FACTOR:	NA
STACK PRESSURE:	29.48	inches Hg.		
NOZZLE DIAMETER:	NA	INCHES		
METER CORR. FACTOR:	0.997			
FINAL METER:	862.849	CUBIC FT.		
INITIAL METER:	841.204	CUBIC FT.		
STACK AREA:	85.573	SQ. FT.		NA
PITOT Cp:	0.84			NA

EMISSION RESULTS

NOZZLE AREA (SQ. FT.):	NA	VOLUMETRIC FLOW(ACFM):	305361
AVG. SQ. RT. VEL. HEAD:	0.8234	VOLUMETRIC FLOW(WVSCFM):	29892
AVG. VEL. HEAD (in H2O):	0.6813	VOLUMETRIC FLOW(DSCFM):	160047
AVG. STACK TEMP. (F):	376.0	**STEAM RATE (LB/Hr):**	**196000**
AVG. METER TEMP. (F):	75.8		
AVG. ORIFICE DIFFERENTIAL:	1.600		
METER ACF:	21.645		
METER SCF:	21.422		
MEASURED SCF MOISTURE:	4.001		
MEASURED MOISTURE %:	15.74		
STACK TEMP. (deg. C):	191.1		
VAPOR PRESSURE:	374.8		
SATURATION MOISTURE %:	NA		
PERCENT WATER VAPOR:	15.74		
GAS MOLECULAR WT.(dry):	29.90		
GAS MOLECULAR WT.(wet):	28.03		
PERCENT EXCESS AIR:	119.225		
AVERAGE VELOCITY(FPS):	59.5		
MMBTUH(if applicable):	**406.95**		
PERCENT ISOKINETIC:	NA		