GEORGIA-PACIFIC CORPORATION

PALATKA MILL

PSD PERMIT APPLICATION
FOR
NO. 4 COMBINATION BOILER MODIFICATIONS

PALATKA (PUTNAM COUNTY), FLORIDA

JULY 2006

RECEIVED
JUL 18 2006
BUREAU OF AIR REGULATION

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

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

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

Air Operation Permit – Use this form to apply for:

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

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Georgia-Pacific Corporation**
2. Site Name: **Palatka Mill**
3. Facility Identification Number: **1070005**
4. Facility Location:
   Street Address or Other Locator: **North of CR 216; West of US 17**
   City: **Palatka** County: **Putnam** Zip Code: **32177**
5. Relocatable Facility? ☐ Yes ☒ No
6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Myra Carpenter, Superintendent of Environmental Affairs**
2. Application Contact Mailing Address:
   Organization/Firm: **Georgia-Pacific Corporation**
   Street Address: **P.O. Box 919**
   City: **Palatka** State: **FL** Zip Code: **32178-0919**
3. Application Contact Telephone Numbers:
   Telephone: **(386) 325-2001** ext. Fax: **(386) 328-0014**
4. Application Contact Email Address: **myra.carpenter@gapac.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	7-14-06
2. Project Number(s):	1070005-038-AC
3. PSD Number (if applicable):	PSD-FL-380
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

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

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

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

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

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

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

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

Application Comment

This application is for the implementation of physical changes to the No. 4 Combination Boiler to allow the increased firing of bark/wood in the boiler. These modifications include upgrades to the bark feed and ash handling system, upgrades to the boiler combustion air system including installation of a new over fire air system, upgrades to the electrical and control equipment, modifications to the existing electrostatic precipitator, and installation of a new dust collector.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
016	No. 4 Combination Boiler	AC1A	$7,500 (paid)

Application Processing Fee

Check one: ☐ Attached - Amount: __ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1. Owner/Authorized Representative Name:
Theodore D. Kennedy, Vice President, Georgia-Pacific, Palatka Operations

2. Owner/Authorized Representative Mailing Address:
Organization/Firm: **Georgia-Pacific Corporation**
Street Address: **P.O. Box 919**
City: **Palatka** State: **FL** Zip Code: **32178**

3. Owner/Authorized Representative Telephone Numbers:
Telephone: **(386) 325-2001** ext. Fax: **(386) 328-0014**

4. Owner/Authorized Representative Email Address: **Ted.Kennedy@gapac.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 FOR TDK   7/17/06
Date

APPLICATION INFORMATION

Application Responsible Official Certification

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

1. Application Responsible Official Name:

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

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

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

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

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

   Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff**
Registration Number: **19011**

2. Professional Engineer Mailing Address:
Organization/Firm: **Golder Associates Inc.****
Street Address: **6241 NW 23rd Street, Suite 500**
City: **Gainesville** State: **FL** Zip Code: **32653**

3. Professional Engineer Telephone Numbers:
Telephone: **(352) 336-5600** ext.**545** Fax: **(352) 336-6603**

4. Professional Engineer Email Address: **dbuff@golder.com**

5. Professional Engineer Statement:

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

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

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

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

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

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

David A. Buff
Signature

7/14/06
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) **434.0**
North (km) **3283.4**

2. Facility Latitude/Longitude:
Latitude (DD/MM/SS) **29/41/0**
Longitude (DD/MM/SS) **81/40/45**

3. Governmental Facility Code: **0**

4. Facility Status Code: **A**

5. Facility Major Group SIC Code: **26**

6. Facility SIC(s): **2611, 2621**

7. Facility Comment :

Facility Contact

1. Facility Contact Name:
Myra Carpenter, Superintendent of Environmental Affairs

2. Facility Contact Mailing Address:
Organization/Firm: **Georgia-Pacific Corporation**
Street Address: **P.O. Box 919**
City: **Palatka** State: **FL** Zip Code: **32178-0919**

3. Facility Contact Telephone Numbers:
Telephone: **(386) 325-2001** ext. Fax: **(386) 328-0014**

4. Facility Contact Email Address: **myra.carpenter@gapac.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 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:	

APPLICATION INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM (Particulate Matter - Total)	**A**	**N**
PM_{10} (Particulate Matter - PM)	**A**	**N**
SO_2 (Sulfur Dioxide)	**A**	**N**
NO_x (Nitrogen Oxides)	**A**	**N**
CO (Carbon Monoxide)	**A**	**N**
VOC (Volatile Organic Compounds)	**A**	**N**
SAM (Sulfuric Acid Mist)	**A**	**N**
TRS (Total Reduced Sulfur)	**A**	**N**
H001 (Acetaldehyde)	**A**	**N**
H021 (Beryllium Compounds)	**B**	**N**
H043 (Chloroform)	**A**	**N**
H095 (Formaldehyde)	**A**	**N**
H106 (Hydrochloric Acid)	**A**	**N**
H115 (Methanol)	**A**	**N**
HAPs (Total Hazardous Air Pollutants)	**A**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

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

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **GP-FI-C1** ☐ Previously Submitted, Date:_____

2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **GP-FI-C2** ☐ Previously Submitted, Date:_____

3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID:_____ ☒ Previously Submitted, Date: **May 2005**

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location:
   ☐ Attached, Document ID:_____ ☒ Not Applicable (existing permitted facility)

2. Description of Proposed Construction or Modification:
   ☒ Attached, Document ID: **PSD Report**

3. Rule Applicability Analysis:
   ☒ Attached, Document ID: **PSD Report**

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

5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.):
   ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable

6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.):
   ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable

7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.):
   ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable

8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.):
   ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable

9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.):
   ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable

10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.):
    ☐ Attached, Document ID:_____ ☒ Not Applicable

APPLICATION INFORMATION

Additional Requirements for FESOP Applications

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

Additional Requirements for Title V Air Operation Permit Applications

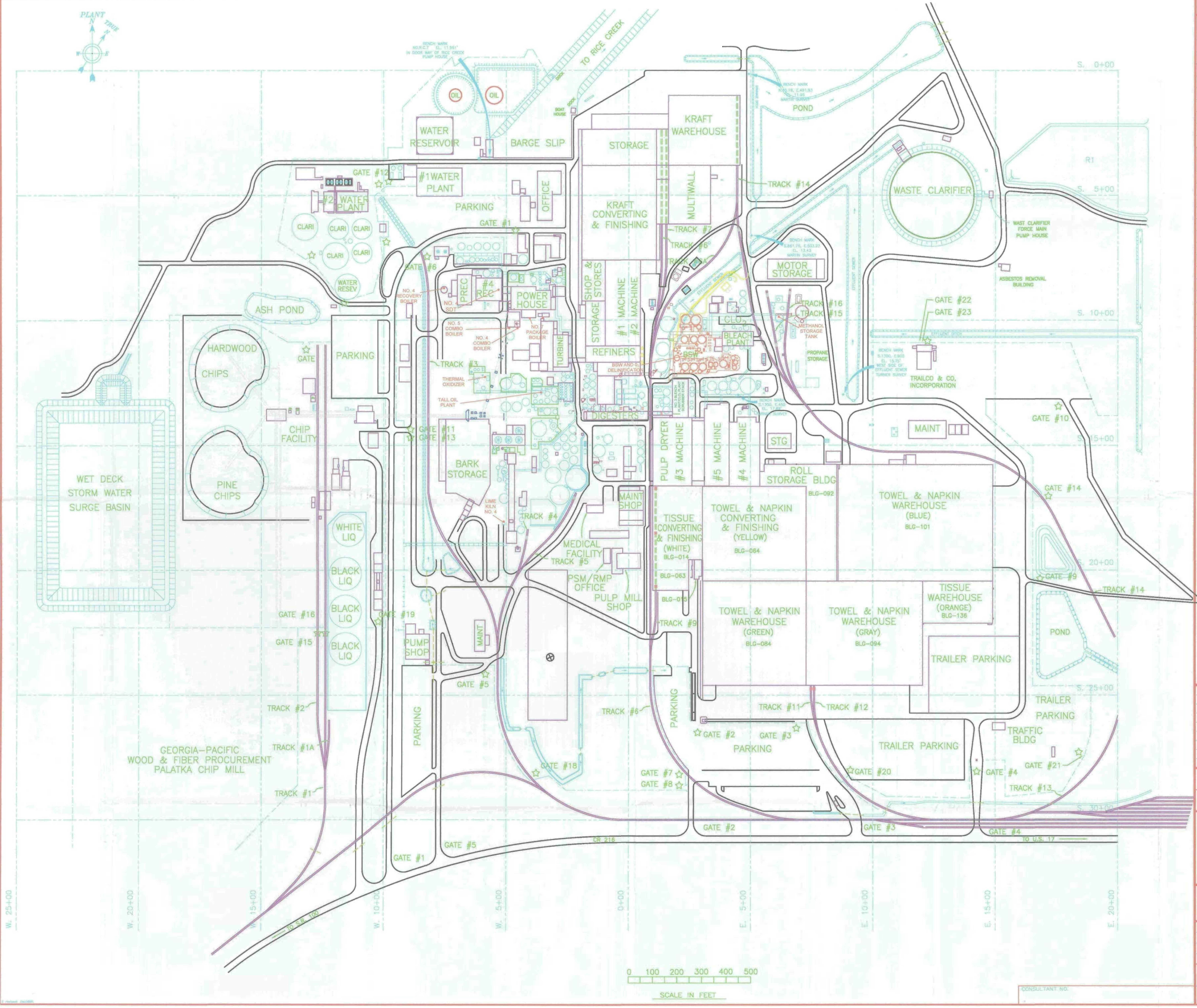
1. List of Insignificant Activities (Required for initial/renewal applications only):
   ☐ Attached, Document ID:_____ ☐ Not Applicable (revision application)
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would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

Additional Requirements Comment

ATTACHMENT GP-FI-C1

FACILITY PLOT PLAN

1070005



NOTES

LEGEND & INFORMATION	
☆	GATE
═	RAILROAD TRACK
— — · —	FENCE

GATE #	DESCRIPTION
1	MAIN GATE
2	EAST GATE
3	OLD CONSTRUCTION GATE
4	TRUCK TRAFFIC GATE
5	CONSTRUCTION GATE
6	R.R. GATE
7	R.R. GATE
8	PERIMETER GATE
9	PERIMETER GATE
10	CONSTRUCTION GATE
11	INNER MILL VEHICLE GATE
12	PERSONNEL GATE
13	PERSONNEL GATE
14	R.R. GATE
15	R.R. GATE
16	R.R. GATE
17	CONSTRUCTION GATE
18	R.R. GATE
19	CHIP TRUCK SCALE
20	R.R. GATE
21	PERSONNEL GATE
22	PERSONNEL GATE
23	PERSONNEL GATE

REV.	DATE	DESCRIPTION	DRN.	CH'D	AP'D
8	5/29/03	CHANGED WOOD PRODUCTS TITLE	VHT		
7	5/19/03	CHANGED DIKE AT OIL STORAGE TANKS	VHT		
6	8/28/02	ADDED UTILITY BRIDGE	VHT		
5	4/11/02	ADDED #3 BLEACH PLANT & NEW CLO2	VHT		
11	01/26/06	ISSUED FOR RECORD	JAL	JCH	JCH
10	04/07/05	ADDED TISSUE WHS, DREGS SYS & DRY STGE	VHT		
9	7/1/03	ADDED SURFACE WATER AND GATES	VHT	SP	
/	/	#21, #22, & #23	/		

CROSS-REFERENCE NO.
E-290-8469-1-0105-001

HUDSON NO.

Georgia-Pacific
THE GROWTH COMPANY
PALATKA OPERATIONS

MILL PLOT PLAN
Attachment GP-FI-CI

DRAWN. TRUJILLO	05/01/96	SCALE	1" = 150'
CHECKED		AFE NO.	
APPROVED		FILENAME	
APPROVED		AREA	

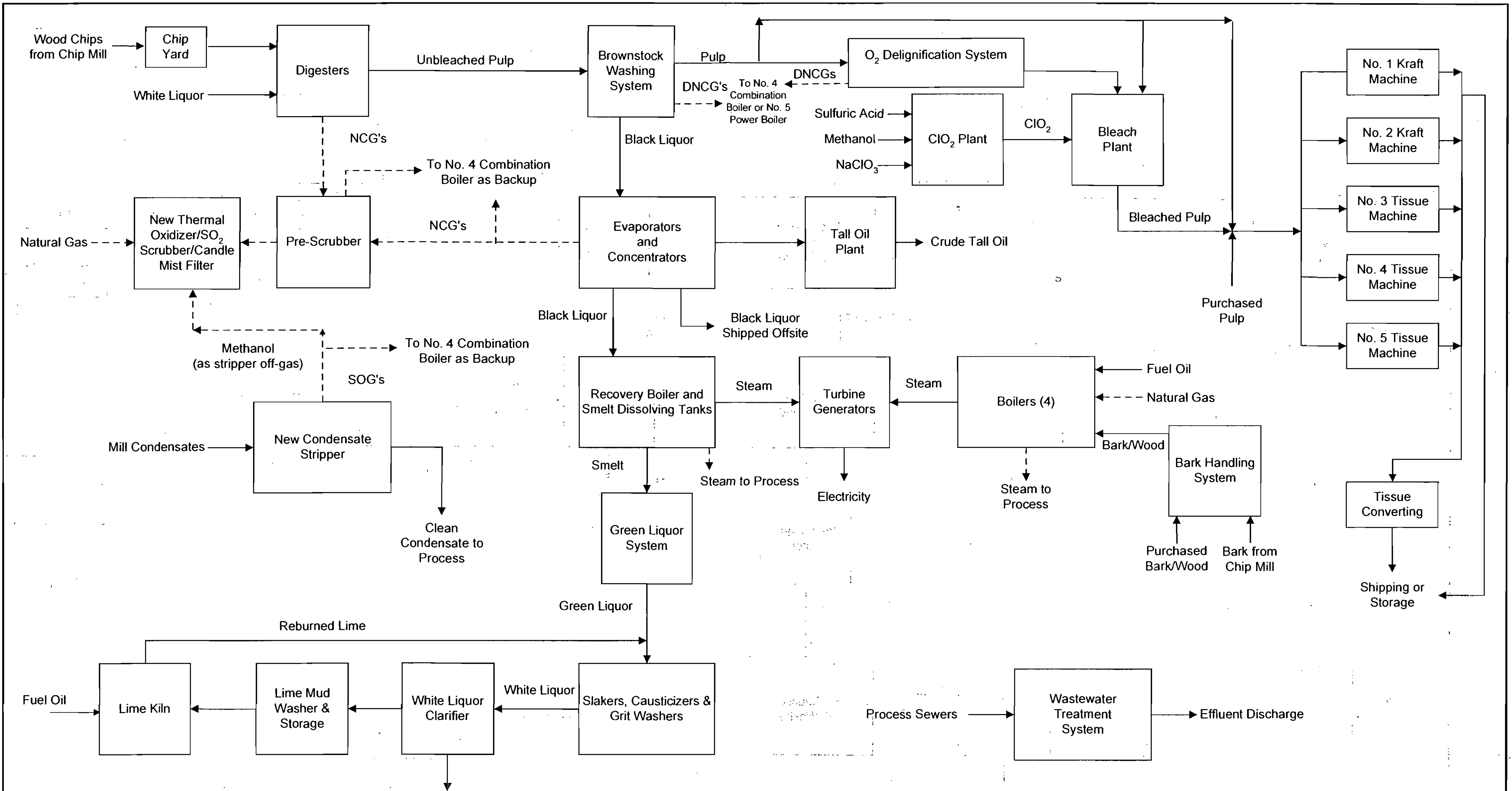
G-P DRAWING NO.
290-8469CV-001-0105-001

CONSULTANT:
CONSULTANT NO.

REV. 11

ATTACHMENT GP-FI-C2

PROCESS FLOW DIAGRAM



ADBP = Air Dried Bleached Pulp
ADUP = Air Dried Unbleached Pulp
CTO = Crude Tall Oil
NCGs = Noncondensable Gases

Attachment GP-FI-C2
Facility Process Flow Diagram
Georgia-Pacific Palatka Operations
Palatka, Florida

Process Flow Legend

Solid/Liquid ——→
Gas - - - - →

Filename: 0537627/4.4 No4 CB/GP-FI-C2_061306.VSD

Date: 6/15/06

Golder Associates

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
   No. 4 Combination Boiler (EU 016)

3. Emissions Unit Identification Number: **016**

4. Emissions Unit Status Code: **A**	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: **26**	8. Acid Rain Unit? ☐ Yes ☒ No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    Dilute Non-condensable Gases (DNCGs) from the Brown Stock Washing System and the O_2 Delignification System sources are routed to the No. 4 Combination Boiler or the No. 5 Power Boiler for TRS and HAP destruction as the primary control device. Exhaust gases from the No. 4 Combination Boiler will be routed to its existing ESP for PM control. In addition, the existing No. 5 Power Boiler ESP may be used for additional PM control. A new mechanical dust collector will also be installed where the existing dust collectors are currently located, which is prior to the existing No. 4 Combination Boiler ESP.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

   Centrifugal Collector
   Electrostatic Precipitator

2. Control Device or Method Code(s): **007, 010**

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:	
3. Maximum Heat Input Rate: **564** 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 is based on firing bark/wood only or in combination with No. 6 fuel oil. Maximum heat input rate shall not be exceeded as a 3-hour average. The maximum heat input rate on an annual basis is synthetically limited to 4,042,127 MMBtu/yr. Natural gas is used as a start-up fuel.**	

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: **No. 4 Combination Boiler**	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: **237** feet	7. Exit Diameter: **8** feet
8. Exit Temperature: **466** °F	9. Actual Volumetric Flow Rate: **278,400** acfm	10. Water Vapor: **22** %
11. Maximum Dry Standard Flow Rate: **135,400** 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 data based on actual stack testing. The dscfm is corrected to 10-percent O_2.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Wood/Bark**		
2. Source Classification Code (SCC): **1-02-009-02**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **59.4**	5. Maximum Annual Rate: **425,487**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **9.5**
10. Segment Comment: **Maximum hourly rate is based on maximum 3-hr average of 564 MMBtu/hr and 4,750 Btu/lb (bark/wood).** **Hourly: 564 MMBtu/hr x 1 lb/4,750 Btu x 1 ton/2,000 lbs = 59.4 TPH** **Annual: Based on 4,042,127 MMBtu/yr, which is GP's proposed maximum annual rate.** **4,042,127 MMBtu/yr x 1 lb/4,750 Btu x 1 ton/2,000 lbs = 425,487 TPY**		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Residual Oil; Grade 6 Oil**		
2. Source Classification Code (SCC): **1-02-004-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **2.791**	5. Maximum Annual Rate: **5,100**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2.35**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
10. Segment Comment: **Maximum 3-hour: 418.6 MMBtu/hr x 1 gal/150,000 Btu = 2,791 gal/hr (max. 3-hour avg.)** **Annual: Limited to 5,100,000 gal/yr as proposed permit condition.** **Residual oil may include No. 6 fuel oil and on-spec used oil.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Natural Gas; >100 MMBtu**		
2. Source Classification Code (SCC): **1-02-006-01**	3. SCC Units: **Million Cubic Feet Burned**	
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: **1,020**
10. Segment Comment: **Natural gas used as a start-up fuel.**		

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	007	010	EL
PM_{10}	007	010	NS
SO_2			EL
NO_x			NS
CO			NS
VOC			NS
HAPs			NS
H095 (Formaldehyde)			NS
H106 (Hydrochloric Acid)			NS
H115 (Methanol)			NS
TRS			EL

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22.6** lb/hour **80.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.04 lbs/MMBtu** Reference: **BACT Proposed Limit**	7. Emissions Method Code: **0**

8. Calculation of Emissions:

Hourly: Due to wood/bark firing –
564 MMBtu/hr x 0.04 lbs/MMBtu = 22.6 lbs/hr
Annual: Due to wood/bark firing –
4,042,127 MMBtu/yr x 0.04 lbs/MMBtu x ton/2,000 lbs = 80.8 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Maximum emissions based on bark/wood firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MMBtu/yr.

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: **0.04 lbs/MMBtu**	4. Equivalent Allowable Emissions: **22.6** lb/hour **80.8** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Proposed limit for bark/wood firing.** **Hourly: 564 MMBtu/hr x 0.04 lbs/MMBtu = 22.6 lbs/hr** **Annual: 4,042,127 MMBtu/yr x 0.04 lbs/MMBtu x ton/2,000 lbs = 80.8 TPY**	

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: **0.04 lbs/MMBtu**	4. Equivalent Allowable Emissions: **16.7** lb/hour **15.3** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Proposed limit for No. 6 fuel oil firing. Hourly emissions based on: 418.6 MMBtu/hr x 0.04 lbs/MMBtu = 16.7 lbs/hr** **Annual fuel oil firing limit based on: 5,100,000 gal/yr x 150,000 Btu/gal x MMBtu/10^6 Btu x 0.04 lbs/MMBtu x ton/2,000 lbs = 15.3 TPY**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.7** lb/hour **59.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **74 % of PM** Reference: **AP-42, Table 1.6-1**	7. Emissions Method Code: **3**
8. Calculation of Emissions: **Max. Hourly: 22.6 lbs/hr PM x 0.74 = 16.7 lbs/hr** **Max. Annual: 80.8 TPY PM x 0.74 = 59.8 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Maximum emissions based on bark/wood firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MMBtu/yr.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **SO_2**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **2,117.0** lb/hour **1,808.8** tons/year

4. Synthetically Limited? ☒ Yes ☐ No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year

6. Emission Factor: **2.35% Sulfur**
Reference: **Current Title V Limit**

7. Emissions Method Code: **0**

8. Calculation of Emissions:

Maximum 24-hour average emissions are 1,921.4 lbs/hr SO_2.
Refer to Attachment GP-EU1-F1.8.

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Refer to Attachment GP-EU1-F1.8. Emissions synthetically limited due to proposed annual limit on fuel oil firing (5.1 million gal/yr) and limit on sulfur content (2.35% S). Includes emissions due to burning of NCGs/SOGs/DNCGs.

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 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.35% Sulfur**	4. Equivalent Allowable Emissions: **1,075.5** lb/hour **982.8** tons/year
5. Method of Compliance: **Fuel Analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Proposed permit limit for fuel oil firing only. Proposed annual fuel oil firing limit of 5,100,000 gal/yr.** **5,100,000 gal/yr x 8.2 lbs/gal x 0.0235 lbs S/lb oil x 2 lbs SO_2/lb S x ton/2,000 lbs = 982.8 TPY** **418.6 MMBtu/hr x gal/150,000 Btu x 8.2 lbs/gal x 0.0235 lbs S/lb oil x 2 lbs SO_2/lb S = 1,075.5 lbs/hr**	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **462.9 lbs/yr (prorated based on actual minutes of NCG burning)**	4. Equivalent Allowable Emissions: **462.9** lb/hour **264.9** tons/year
5. Method of Compliance: **Tracking of time and pulp production during which LVHC NCGs are burned. LVHC NCG burning limited to maximum of 264.9 TPY SO_2.**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions reflect LVHC NCG/SOG burning only. Hourly emissions based on 462.9 lbs/hr from LVHC NCG burning and 496.0 lbs/hr from SOG burning.** **Refer to Attachment GP-EU1-F1.8. Permit No. 1070005-024-AC.**	

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.70 lbs SO_2/ton ADUP**	4. Equivalent Allowable Emissions: **82.6** lb/hour **236.3** tons/year
5. Method of Compliance: **Tracking of time during which HVLC (dilute NCGs) are burned. HVLC burning time allowed for 8,760 hr/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions reflect HVLC (dilute NCGs) burning only. Permit No. 1070005-024-AC.** **118 TPH ADUP x 0.35 lbs S/ton ADUP x 2 lbs SO_2/lb S = 82.6 lbs/hr** **675,250 TPY ADUP x 0.35 lbs S/ton ADUP x 2 lbs SO_2/lb S x ton/2,000 lbs = 236.3 TPY**	

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 4 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **496.0 lbs/hr (prorated based on actual minutes of SOG burning)**	4. Equivalent Allowable Emissions: **496.0** lb/hour **283.8** tons/year
5. Method of Compliance: **Tracking of time and pulp production during which SOGs are burned. SOGs burning limited to maximum of 283.8 TPY SO_2.**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions reflect SOG burning only. Refer to Attachment GP-EU1-F1.8 and Permit No. 1070005-024-AC.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **178.6** lb/hour **534.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.24 lb/MMBtu for bark/wood** **0.27 lb/MMBtu for fuel oil** Reference: **Proposed limit based on test data and vendor information.**	7. Emissions Method Code: **0**

8. Calculation of Emissions:

Hourly:

Wood/Bark - 564 MMBtu/hr x 0.24 lbs/MMBtu = 135.4 lbs/hr

SOGs – 0.9 lbs NO_x/1,000 gal condensate (based on NCASI TB 802) x 48,000 gal/hr condensate = 43.2 lbs/hr

Total – 135.4 + 43.2 = 178.6 lbs/hr

Annual:

Wood/Bark – 3,277,127 MMBtu/yr x 0.24 lbs/MMBtu (based on test data) x ton/2,000 lbs = 393.3 TPY

Fuel Oil – 5,100,000 gal/yr x 150,000 Btu/gal x 0.27 lbs/MMBtu (based on AP-42, Table 1.3-1) x ton/2,000 lbs x MMBtu/10^6 Btu = 103.3 TPY

SOGs – Burned up to 20% of the time: 43.2 lbs/hr x 8,760 hr/yr x 0.20 x ton/2,000 lbs = 37.84 TPY

Total – 393.3 + 103.3 + 37.84 = 534.4 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Maximum annual emissions based on maximum fuel oil burning with remainder due to bark/wood burning plus NO_x due to SOG burning. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MMBtu/yr. Factors in lb/MMBtu are proposed BACT limits based on an over-fire air system and low NO_x burners.

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: **0.24 lbs/MMBtu for bark/wood**	4. Equivalent Allowable Emissions: **135.4** lb/hour **485.1** tons/year
5. Method of Compliance: **EPA Method 7 or 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Proposed limit for bark/wood firing only.** **Hourly: 564 MMBtu/hr x 0.24 lbs/MMBtu = 135.4 lbs/hr.** **Annual: 4,042,128 MMBtu/yr x 0.24 lbs/MMBtu = 485.1 TPY.**	

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: **0.27 lbs/MMBtu for oil**	4. Equivalent Allowable Emissions: **113.0** lb/hour **103.3** tons/year
5. Method of Compliance: **EPA Method 7 or 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Proposed limit for fuel oil firing only. Based on AP-42 factor for normal firing with low-NO$_x$ burners (Table 1.3-1):** **Hourly: 418.6 MMBtu/hr x 0.27 lbs/MMBtu = 113.0 lbs/hr** **Annual: 5,100,000 gal/yr x 150,000 Btu/gal x 0.27 lbs/MMBtu x ton/2,000 lbs = 103.3 TPY**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **282.0** lb/hour **1,010.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.5 lb/MMBtu** Reference: **Proposed BACT limit**	7. Emissions Method Code: **0**

8. Calculation of Emissions:

Max. Hourly: Due to wood/bark firing –
564 MMBtu/hr x 0.50 lbs/MMBtu = 282.0 lbs/hr
Max. Annual: Due to wood/bark firing –
4,042,127 MMBtu/yr x 0.50 lbs/MMBtu x ton/2,000 lbs = 1,010.5 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Emission factor shown is for bark/wood firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MMBtu/yr.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **9.6** lb/hour **34.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.017 lb/MMBtu** Reference: **AP-42, Table 1.6-4**	7. Emissions Method Code: **3**

8. Calculation of Emissions:

Max. Hourly: Due to wood/bark firing –
564 MMBtu/hr x 0.017 lbs/MMBtu = 9.6 lbs/hr
Max. Annual: Due to wood/bark firing –
4,042,127 MMBtu/yr x 0.017 lbs/MMBtu x ton/2,000 lbs = 34.4 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Emission factor shown is for bark/wood firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MMBtu/yr.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **TRS**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.6** lb/hour **15.7** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5 ppmvd @ 10% O_2** Reference: **Rule 62-296.404(3)(f)1 and Permit No. 1070005-024-AC.**	7. Emissions Method Code: **0**

8. Calculation of Emissions:

Hourly: **5 ppmvd/10^6 x 14.7 lb/in^2 x 144 in^2/ft^2 x 135,400 dscfm x 60 min/hr x 34 lb_m/lb-mole / 1,545.6 ft-lb_f/lb-mole -°R x 1/528°R = 3.6 lbs/hr**

Annual: **3.6 lbs/hr x 8,760 hr/yr x 1 ton/2,000 lbs = 15.7 TPY**

TRS reported as H_2S.

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Limit applies when the No. 4 Combination Boiler is being used as a backup combustion device for LVHC (NCG/SOG) gas stream, or as the primary combustion device for the HVLC (DNCG) gas stream, since these are the only times the No. 4 Combination Boiler will have TRS emissions.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5 ppmvd @10% O_2**	4. Equivalent Allowable Emissions: **3.6** lb/hour **15.7** tons/year
5. Method of Compliance: **Maintain minimum temperature of 1,200°F and the 0.5-second residence time as required by rule at 150,000 lbs/hr steaming rate.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.404(3)(f)1 and Permit No. 1070005-024-AC.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE30**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **30** % Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **Annual test using EPA Method 9.**	
5. Visible Emissions Comment: **Permit No. 1070005-024-AC. Applies to carbonaceous fuel burning only, or to carbonaceous fuel combined with fuel oil.**	

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 _____ of _____

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

Continuous Monitoring System: Continuous Monitor _____ of _____

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: GP-EU1-I1 ☐ Previously Submitted, Date ____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: GP-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: GP-EU1-I3 ☐ Previously Submitted, Date ____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ 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: GP-EU1-I7 ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☒ Attached, Document ID: **Part B** ☐ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☒ Attached, Document ID: **Part B** ☐ 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

EMISSIONS UNIT INFORMATION

Section [1] of [1]

No. 4 Combination Boiler

Additional Requirements Comment

ATTACHMENT GP-EU1-F1.8

CALCULATION OF EMISSIONS

ATTACHMENT GP-EU1-F1.8
CALCULATION OF EMISSIONS
NO. 4 COMBINATION BOILER

1. MAXIMUM 1-HOUR AND 3-HOUR SO_2 EMISSION RATE

(Refer to ATTACHMENT GP-EU1-F1.8a)

A. LOW-VOLUME, HIGH CONCENTRATION (LVHC) NON-CONDENSABLE GASES (NCGs)

Maximum hourly pulp production = 118 tons per hour (TPH) air-dried unbleached pulp (ADUP).

Sulfur loading from LVHC gas stream = 378 lbs S/hr; based on 1,850 tons per day (TPD) ADUP pulp production.

Therefore, sulfur loading at 118 TPH ADUP = 378 x 118 / (1,850 ÷ 24) = 578.6 lbs S/hr.

Pre-scrubber sulfur removal efficiency estimated to be at least 60%.

Conversion of sulfur to SO_2:

1 lb mol SO_2/1 lb mol S x 64 lbs SO_2/lb mol SO_2 x lb mol S/32 lbs S = 2 lbs SO_2/lb S

578.6 lbs S/hr x 2 lbs SO_2/lb S x (1-0.6) = 462.9 lbs/hr SO_2

B. STRIPPER OFF-GASES (SOGs)

Sulfur loading from SOG stream = 162 lbs S/hr; based on 1,850 TPD ADUP pulp production.

Therefore, sulfur loading at 118 TPH ADUP = 162 x 118 / (1,850 ÷ 24) = 248.0 lbs S/hr.

248.0 lbs/hr S x 2 lbs SO_2/lb S = 496.0 lbs/hr SO_2

SOGs do not go through pre-scrubber.

C. FUEL OIL FIRING

Based on 2.35 percent sulfur fuel oil, which is equivalent to 0.0235 lbs S/lbs oil.

418.6 MMBtu/hr x 1 gal/150,000 Btu x 8.2 lbs/gal x 0.0235 lbs S/lbs oil x 2 lbs SO_2/lb S = 1,075.5 lbs/hr

D. HIGH-VOLUME, LOW CONCENTRATION (HVLC) DILUTE NCGs (DNCGs)

Sulfur loading from DNCG stream = 0.35 lbs S/ton ADUP

Based on 118 TPH ADUP pulp production rate:

118 TPH ADUP x 0.35 lbs S/ton ADUP x 2 lbs SO_2/lb S = 82.6 lbs/hr SO_2

E. TOTAL

Total Hourly: 462.9 lbs/hr + 496.0 lbs/hr + 1,075.5 lbs/hr + 82.6 lbs/hr = 2,117.0 lbs/hr

2. MAXIMUM 24-HOUR SO_2 EMISSION RATE

(Refer to ATTACHMENT GP-EU1-F1.8b)

A. LVHC NCGs

Sulfur loading from LVHC gas stream = 378 lbs S/hr x 2,300 / 1,850 = 470 lbs S/hr; based on 2,300 TPD ADUP pulp production.

Pre-scrubber sulfur removal efficiency estimated to be at least 60%.

Conversion of sulfur to SO_2:

470 lbs S/hr x 2 lbs SO_2 /lb S x (1-0.6) = 376 lbs /hr SO_2

376 lbs/hr SO_2 x 24 hrs/day = 9,023 lbs/day SO_2

B. SOGs

Sulfur loading from SOG stream = 162 lbs S/hr x 2,300 / 1,850 = 201 lbs S/hr; based on 2,300 TPD ADUP pulp production.

SOGs do not go through pre-scrubber.

201 lbs/hr S x 2 lbs SO_2/lb S = 402.8 lbs/hr SO_2

402 lbs/hr SO_2 x 24 hrs/day = 9,667.5 lbs/day SO_2

C. FUEL OIL FIRING

418.6 MMBtu/hr x 1 gal / 150,000 Btu x 8.2 lbs oil/gal x 0.0235 lbs S/lb oil x 2 lbs SO_2/lb S = 1,075.5 lbs/hr

1,075.5 lbs/hr SO_2 x 24 hrs/day = 25,812.6 lbs/day SO_2

D. HVLC DNCGs

Based on 2,300 tons/day ADUP pulp production rate.

2,300 TPD ADUP x 0.35 lbs S/ton ADUP = 1,610.0 lbs/day SO_2

E. TOTAL

Total 24-Hour: 9,023 lbs/day + 9,668 lbs/day + 25,812.6 lbs/day + 1,610.0 lbs/day = 46,113 lbs/day

24-hour average = 46,113 lbs/day ÷ 24 hrs/day = 1,921 lbs/hr SO_2

3. MAXIMUM ANNUAL SO_2 EMISSION RATE

(Refer to ATTACHMENT GP-EU1-F1.8c)

A. LVHC NCGs

Sulfur loading from LVHC gas stream = 378 lbs S/hr; based on 1,850 TPD ADUP, maximum monthly average (675,250 TPY) pulp production:

LVHC NCG burning in No. 4 Combination Boiler limited to 20% on an operating hours basis.

Pre-scrubber sulfur removal efficiency estimated to be at least 60%.

Conversion of sulfur to SO_2:

378 lbs S/hr x 2 lbs SO_2/lb S x (1-0.6) x 0.20 x 8,760 hrs/yr ÷ 2,000 lbs/ton = 264.9 TPY SO_2

B. SOGs

Sulfur loading from SOG stream = 162 lbs S/hr; based on 1,850 TPD ADUP, maximum monthly average (675,250 TPY) pulp production.

SOG burning in No. 4 Combination Boiler limited to 20% on an operating hours basis.

SOGs do not go through pre-scrubber.

162 lbs S/hr x 2 lbs SO_2/lb S x 0.20 x 8,760 hrs/yr ÷ 2,000 lbs/ton = 283.8 TPY SO_2

C. FUEL OIL FIRING

Annual fuel oil firing limited to 5,100,000 gal/yr. Based on 2.35 percent sulfur fuel oil, which is equivalent to 0.0235 lbs S/lbs oil.

5,100,000 gal/yr x 8.2 lbs/gal x 0.0235 lbs S/lb oil x 2 lbs SO_2/lb S x 1 ton/2,000 lbs = 982.8 TPY SO_2.

D. HVLC DNCGs

Based on 1,850 TPD ADUP, maximum monthly average pulp production rate, or 675,250 TPY ADUP.

675,250 TPY ADUP x 0.35 lbs S/ton ADUP x 2 lbs SO_2/lb S x 1 ton/2,000 lbs = 236.3 TPY SO_2

E. BARK/WOOD FIRING

Heat input to boiler limited to 4,042,127 MMBtu/yr. Total fuel oil limited to 5,100,000 gal/year.

Therefore, remainder of heat input due to bark/wood = 4,042,127 MMBtu/yr – (5,100,000 gal/year x 150,000 Btu/gal) = 3,277,127 MMBtu/yr

SO_2 Emission factor = 0.025 lb/MMBtu (AP-42, Table 1.6-2)

3,277,127 MMBtu/yr x 0.025 lb/MMBtu x ton/2,000 lb = 41.0 TPY SO_2

F. TOTAL

Total Annual: 264.9 TPY + 283.8 TPY + 982.8 TPY + 236.3 TPY + 41.0 = 1,808.8 TPY SO_2.

Note: Emissions do not account for SO_2 removal in boiler.

ATTACHMENT GP-EU1-F1.8a
CALCULATION OF MAXIMUM HOURLY SO2 EMISSIONS FROM NO. 4 COMBINATION BOILER

Source	Maximum Pulp Production (TPH ADUP)	Uncontrolled TRS Emissions		Potential Uncontrolled SO_2 Emissions (lbs/hr)	Pre-scrubber Sulfur Removal Efficiency (%)	Maximum SO_2 Emission Rate[c] (lbs/hr)
		lbs S/hr[a]	lbs S/ton ADUP[b]			
FUEL OIL COMBUSTION						
Permitted No. 6 Fuel Oil Burning @ 2.35% S	--	--	--	1,075.5 [d]	--	1,075.5
LVHC/SOG DESTRUCTION						
LVHC NCGs	118	578.6	--	1,157.3	60 [e]	462.9
Condensate Stripper Off-Gas	118	248.0	--	496.0	0	496.0
Subtotal	118	826.6	--	1,653.3		958.9
HVLC DESTRUCTION						
HVLC DNCGs	118	--	0.35	82.6	--	82.6
					TOTALS	2,117.0

Note:

NCGs = noncondensable gases	SO_2 = sulfur dioxide	HVLC = high volume, low concentration
TRS = total reduced sulfur	LVHC = low volume, high concentration	DNCGs = dilute noncondensable gases
TPH = tons per hour	SOG = condensate stripper off-gas	

Footnotes:

[a] As sulfur, based on pulp production of 118 TPH. Based on engineering estimates and test data, which shows 70%/30% split of sulfur between NCGs and SOG.

[b] As sulfur. Based on worst-case engineering estimate from AMEC Forest Industry Consulting.

[c] No removal of SO_2 in No. 4 Combination Boiler is assumed.

[d] Based on 418.6 MMBtu/hr fuel oil usage; 150,000 Btu/gal; 2.35% sulfur; and the equation: SO_2 = gal/hr oil x % S oil/100 x 8.2 lbs/gal x 2 lbs SO_2/lbs S

[e] TRS pre-scrubber provides minimum of 60% sulfur removal.

ATTACHMENT GP-EU1-F1.8b
CALCULATION OF MAXIMUM 24-HOUR SO2 EMISSIONS FROM NO. 4 COMBINATION BOILER

Source	Maximum Pulp Production (TPD ADUP)	Uncontrolled TRS Emissions lbs S/hr[a]	Uncontrolled TRS Emissions lbs S/ton ADUP[b]	Potential Uncontrolled SO_2 Emissions (lbs/hr)	Pre-scrubber Sulfur Removal Efficiency (%)	Maximum SO_2 Emission Rate[c] lbs/hr	Maximum SO_2 Emission Rate[c] lbs/day
FUEL OIL COMBUSTION							
Permitted No. 6 Fuel Oil Burning @ 2.35% S	--	--	--	1,075.5 [d]	--	1,075.5	25,812.6
LVHC/SOG DESTRUCTION							
LVHC NCGs	2,300	469.9	--	939.9	60 [e]	376.0	9,023.0
Condensate Stripper Off-Gas	2,300	201.4	--	402.8	0	402.8	9,667.5
Subtotal	2,300	671.4	--	1,342.7		778.8	18,690.4
HVLC DESTRUCTION							
HVLC DNCGs	2,300	--	0.35	67.1	--	67.1	1,610.0
					TOTALS	1,921.4	46,113.0

Note:

NCGs = noncondensable gases
TRS = total reduced sulfur
TPH = tons per hour
SO_2 = sulfur dioxide
LVHC = low volume, high concentration
SOG = condensate stripper off-gas
HVLC = high volume, low concentration
DNCGs = dilute noncondensable gases

Footnotes:

[a] As sulfur, based on pulp production of 2,300 TPD. Based on engineering estimates and test data, which shows 70%/30% split of sulfur between NCGs and SOG.

[b] As sulfur. Based on worst-case engineering estimate from AMEC Forest Industry Consulting.

[c] No removal of SO_2 in No. 4 Combination Boiler is assumed.

[d] Based on 418.6 MMBtu/hr fuel oil usage; 150,000 Btu/gal; 2.35% sulfur; and the equation: SO_2 = gal/hr oil x % S oil/100 x 8.2 lbs/gal x 2 lbs SO_2/lbs S

[e] TRS pre-scrubber provides minimum of 60% sulfur removal.

ATTACHMENT GP-EU1-F1.8c

CALCULATION OF MAXIMUM ANNUAL SO2 EMISSIONS FRON NO. 4 COMBINATION BOILER

Source	Maximum Pulp Production (TPY ADUP)	Uncontrolled TRS Emissions		Potential Uncontrolled SO_2 Emissions (lbs/hr)	Pre-scrubber Sulfur Removal Efficiency (%)	Maximum SO_2 Emission Rate [c] (TPY)
		lbs/hr [a]	lbs S/ton ADUP [b]			
FUEL OIL COMBUSTION						
Maximum No. 6 Fuel Oil Burning @ 2.35% S	--	--	--	--	--	982.8 [d]
BARK/WOOD COMBUSTION						
Remainder of Heat Input	--	--	--	--	--	41.0 [f]
LVHC/SOG DESTRUCTION @ 20% UPTIME						
LVHC NCGs	675,250	378.0	--	756.0	60 [e]	264.9
Condensate Stripper Off-Gas	675,250	162.0	--	324.0	0	283.8
Subtotal	675,250	540.0	--	1,080.0		548.7
HVLC DESTRUCTION @ 100% UPTIME						
HVLC DNCGs	675,250	--	0.35	--	--	236.3
					TOTALS	1,808.8

Note:

NCGs = noncondensable gases

TRS = total reduced sulfur

TPH = tons per hour

SO_2 = sulfur dioxide

LVHC = low volume, high concentration

SOG = condensate stripper off-gas

HVLC = high volume, low concentration

DNCGs = dilute noncondensable gases

Footnotes:

[a] As sulfur, based on pulp production of 1,850 TPD ADUP (675,250 TPY ADUP). Based on engineering estimates and test data, which shows 70%/30% split of sulfur between NCGs/SOG.

[b] As sulfur. Based on worst-case engineering estimate from AMEC Forest Industry Consulting.

[c] No removal of SO_2 in No. 4 Combination Boiler is assumed.

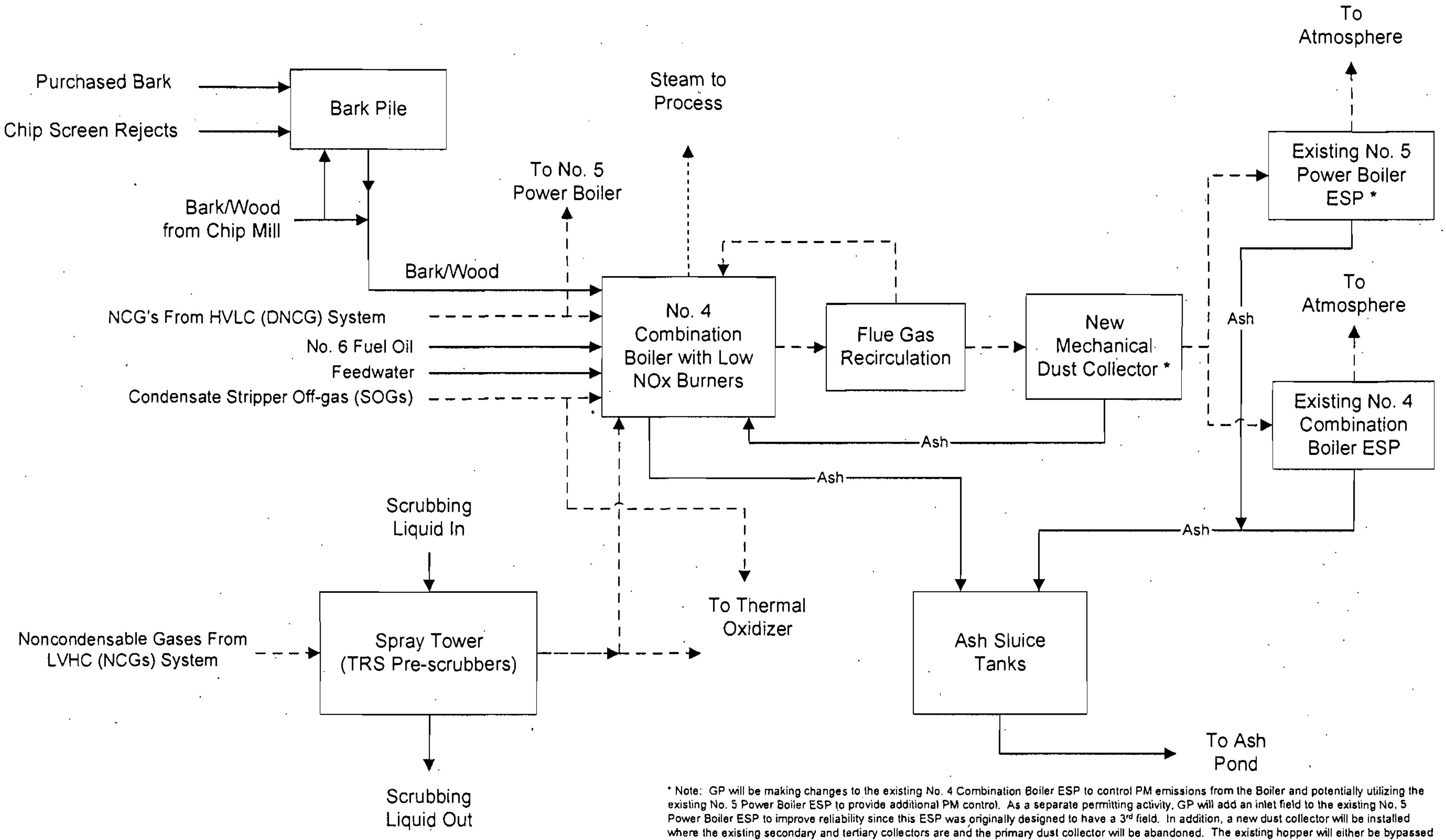
[d] Based on 5,100,000 gal/yr fuel oil usage; 150,000 Btu/gal; 2.35% sulfur; and the equation: SO_2 = gal oil x % S oil/100 x 8.2 lbs/gal x 2 lbs SO_2/lbs S.

[e] TRS pre-scrubber provides minimum of 60% sulfur removal.

[f] Based on total heat input to boiler (4,042,127 MMBtu/yr) minus maximum fuel oil input (765,000 MMBtu/yr) = 3,277,127 MMBtu/yr and AP-42 factor of 0.025 lb SO_2/MMBtu for wood/bark burning.

ATTACHMENT GP-EU1-I1

PROCESS FLOW DIAGRAM



* Note: GP will be making changes to the existing No. 4 Combination Boiler ESP to control PM emissions from the Boiler and potentially utilizing the existing No. 5 Power Boiler ESP to provide additional PM control. As a separate permitting activity, GP will add an inlet field to the existing No. 5 Power Boiler ESP to improve reliability since this ESP was originally designed to have a 3rd field. In addition, a new dust collector will be installed where the existing secondary and tertiary collectors are and the primary dust collector will be abandoned. The existing hopper will either be bypassed with new ductwork or gutted and used to remove heavy particulate.

Attachment GP-EU1-I1
Process Flow Diagram
No. 4 Combination Boiler
Georgia-Pacific Palatka Mill

Process Flow Legend

Solid/Liquid ———→
Gas – – – –→
Steam - - - - - - - →

Filename: 4.4 No. 4 CB/GP-EU1-I1_061306.VSD
Date: 06/15/06

Golder Associates

ATTACHMENT GP-EU1-I2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT GP-EU1-I2

NO. 4 COMBINATION BOILER
FUEL ANALYSIS

Fuel	Density (lb/gal)	Moisture (%)	Weight % Sulfur	Weight % Ash	Heat Capacity
No. 6 Fuel Oil[a]	8.2	----	2.35	0.15	145,000 - 150,000 Btu/gallon
Bark/Wood	----	38	----	2.45	4,500 Btu/lb

Note: This unit is equipped with natural gas igniters which are only used for approximately 10 seconds during startup. Heat input and emissions from the igniters are negligible.

[a] Fuel oil may include on-spec used oil.

ATTACHMENT GP-EU1-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

ATTACHMENT GP-EU1-I3

CONTROL EQUIPMENT
NO. 4 COMBINATION BOILER

The No. 4 Combination Boiler is equipped with a new multiclone dust collector and an existing electrostatic precipitator (ESP) for particulate matter control. Design information for the control devices is presented below.

Parameter	**No. 4 Combination Boiler – Mechanical Dust Collector**
Manufacturer	To Be Determined
Inlet Gas Temp (°F)	700
Inlet Gas Flow (ACFM)	280,000
Pressure Drop (in. H_2O)	<3
Control Efficiency (%)	80-90

Parameter	**No. 4 Combination Boiler - Electrostatic Precipitator**
Manufacturer	Research Cottrell
Inlet Gas Temp (°F)	325
Gas Flow Rate (ACFM)	455,000
Primary Voltage (V)	0-600
Secondary Voltage (kVdc)	0-90
Primary Current (A)	0-150
Secondary Current (A)	0-1.0
Control Efficiency (%)	99.5

The existing No. 5 Power Boiler ESP will potentially be utilized to provide additional particulate matter control. Design information for the No. 5 Power Boiler ESP is presented below.

Parameter	**No. 5 Power Boiler Electrostatic Precipitator**
Manufacturer	Research Cottrell
Inlet Gas Temp (°F)	325
Gas Flowrate (acfm)	455,000
Primary Voltage (V)	0-600
Secondary Voltage (kVdc)	0-90
Primary Current (A)	0-150
Secondary Current (A)	0-1.0
Control Efficiency (%)	99.5

ATTACHMENT GP-EU1-I7

OTHER INFORMATION REQUIRED BY RULE OR STATUTE

ATTACHMENT GP-EU1-I7

LIST OF APPLICABLE REGULATIONS

40 CFR 63, Subpart DDDDD – NESHAPs for Industrial Boilers

40 CFR 63.443(d)(4)–MACT Standards - HAP Reduction in a Boiler or Lime Kiln

40 CFR 63.443(e)(1)–Periods of Excess Emissions

62-296.310–General Test Requirements

62-296.404(3)(f)–Kraft Pulp Mills

62-296.404(4)(e)–Kraft Pulp Mills

62-296.410(1)(b)–Carbonaceous Fuel Burning Equipment

62-296.410(3)–Test Methods and Procedures

62-297.401(1)(a)–EPA Method 1 - Sample and Velocity Traverses for Stationary Sources

62-297.401(2)–EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate

62-297.401(3)–EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight

62-297.401(4)–EPA Method 4 - Determination of Moisture Content in Stack Gases

62-297.401(5)–EPA Method 5 - Determination of Particulate Emissions from Stationary Sources

62-297.401(6)–EPA Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources

62-297.401(9)(a)–EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources

TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

LIST OF TABLES

TABLE OF CONTENTS
(continued)

LIST OF APPENDICES

TABLE OF CONTENTS
(continued)

LIST OF ACRONYMS AND ABBREVIATIONS

AAQS	Ambient Air Quality Standards
AOR	annual operating report
APH	air preheater
B&W	Babcock & Wilcox
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
GP	Georgia-Pacific Corporation
H_2O	water
HAP	hazardous air pollutant
HCl	hydrogen chloride
Hg	mercury
HSH	highest, second-highest
km	kilometer
LAER	lowest achievable emission rate

TABLE OF CONTENTS
(continued)

LIST OF ACRONYMS AND ABBREVIATIONS (cont'd)

lbs/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
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
NHPP	New Hope Power Partnership
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

TABLE OF CONTENTS
(continued)

LIST OF ACRONYMS AND ABBREVIATIONS (cont'd)

SAM	sulfuric acid mist
scf/hr	standard cubic foot per hour
SCR	selective catalytic reduction
SIL	significant impact level
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 Clewiston Mill
µm	micrometer
$\mu g/m^3$	micrograms per cubic meter
VOC	volatile organic compound

1.0 INTRODUCTION

Georgia-Pacific Corporation (GP) is proposing changes to the No. 4 Combination Boiler at its Kraft pulp and paper mill located in Palatka, Putnam County, Florida. The GP Palatka Mill consists of the following major process operations: chipyard, digester system, brownstock washing system, bleaching system, chemical recovery area, paper drying/converting/warehousing, and power/utilities area. The Mill is currently operating under Title V Permit No. 1070005-034-AV, most recently issued on December 20, 2005.

GP currently operates the No. 4 Combination Boiler, which burns bark/wood, No. 6 fuel oil and on-spec used oil, and small quantities of natural gas (during start-up) to generate steam for the various papermaking process operations. In addition, the Boiler serves as a destruction device for noncondensable gases (NCGs), stripper off-gases (SOGs), and dilute, noncondensable gases (DNCGs), which are generated by various process sources. GP is requesting changes to the No. 4 Combination Boiler in order to increase the actual amount of bark/wood fuel that can be burned in the Boiler.

The changes GP is proposing will also allow the Boiler to meet the Maximum Achievable Control Technology (MACT) standards for Industrial, Commercial and Institutional Boilers and Process heaters, promulgated under Title 40 of the Code of Federal Regulations, Part 63 (40 CFR 63), Subpart DDDDD. The compliance date for existing boilers under Subpart DDDDD is September 13, 2007.

GP is proposing a number of changes to the No. 4 Combination Boiler, including:

- Upgrading the bark/wood fuel delivery system by replacing worn out feed system parts, replacing the existing bark surge bin, modifying conveyors to accommodate these changes, and installing new air swept bark distributors;
- Installing a new overfire air (OFA) system;
- Installing a new mechanical dust collector to replace the existing cyclones;
- Making changes to the existing electrostatic precipitator (ESP) used to control particulate matter (PM) emissions from the Boiler, and potentially utilizing the existing No. 5 Power Boiler ESP to provide additional PM control (in this case, a new ESP will be installed for the No. 5 Power Boiler);
- Modifying the NCG piping for incorporation into the new OFA system;

- Installing new low-nitrogen oxides (NO_x) burners (LNB) for fuel oil firing. The new burners will be of the same capacity and number as the existing burners; and

GP is also evaluating installing new baffles for better undergrate air distribution for the No. 4 Combination Boiler. Engineering evaluations are ongoing, and final engineering may dictate that some of these changes will be implemented, while others may not.

The project will result in an increase in the actual amount of bark/wood fuel burned in the Boiler. In addition, the current permitted maximum bark/wood heat input and burning rate will be increased as part of this project. The increase in the bark/wood burned in the Boiler will offset No. 6 fuel oil that is normally combusted.

GP is also permanently shutting down the No. 4 Power Boiler as part of this project.

Actual-to-potential emission increases for this project have been added to increases for other past and future projects, even though those projects are unrelated. GP continues to believe this process of aggregating unrelated projects, as dictated by the Florida Department of Environmental Protection (FDEP), is inconsistent with past guidance on this topic. Nevertheless, in the interest of time, the combined increases are presented in this application. Based on the comparison of past actual annual emissions to future potential annual emissions from the No. 4 Combination Boiler and other projects GP is proposing, emission increases of NO_x, carbon monoxide (CO), PM, particulate matter less than or equal to 10 microns (PM_{10}), volatile organic compounds (VOCs), and sulfuric acid mist (SAM) will trigger new source review (NSR) under the federal and State prevention of significant deterioration (PSD) regulations.

For each pollutant 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 that are below specified significant impact levels;

2. Application of best available control technology (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 which are 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 four additional sections, followed by appendices. A description of the project, including air emission sources 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. Supporting documentation is presented in the Appendices.

The air quality impact analysis and additional impact analysis required by PSD rules is being submitted to the FDEP in a separate modeling report as Attachment C of the No. 4 Recovery Boiler/No. 4 Lime Kiln application. That application is being submitted concurrently with this No. 4 Combination Boiler application.

2.0 PROJECT DESCRIPTION

GP is proposing to modify the No. 4 Combination Boiler to increase the actual amount of bark/wood burned in the Boiler. As part of the project, GP is also proposing to permanently shutdown the No. 4 Power Boiler. The facility is currently operating under Title V Permit No. 1070005-034-AV, issued December 20, 2005. The facility is located west of U.S. Hwy 17, on State Road (SR) 216, north of Palatka in Putnam County. A plot plan of the facility, showing stack locations, is presented in Attachment GP-FI-C1 of the application form. The following sections describe the proposed projects in more detail.

2.1 Existing Operations

GP currently operates the No. 4 Combination Boiler to provide steam to the papermaking process and the turbine generators that provide electricity for the facility. The Boiler is of Babcock & Wilcox (B&W) design, with a design steam rating of 360,000 pounds per hour (lbs/hr). Actual maximum hourly steam production in 2005 for the Boiler was 383,500 lbs/hr, with a maximum 24-hour production of 344,000 lbs/hr.

- The No. 4 Combination Boiler is currently permitted to burn the following fuels and gases:
- Carbonaceous fuel, such as tree bark and wood fuel (supplied from the Bark Handling System).
- No. 6 fuel oil, with a sulfur content not to exceed 2.35 percent by weight, with or without blended on-spec used oil.
- Natural gas as a startup fuel (the natural gas may be kept on pilot for flame safety).
- NCGs from the low-volume, high concentration (LVHC) gas collection system, and/or SOGs (as a backup to the Thermal Oxidizer). DNCGs from the Brown Stock Washer and Oxygen Delignification Systems are burned in the Boiler as the primary destruction device. The burning of the NCGs, SOGs, and DNCGs in the No. 4 Combination Boiler was all permitted as part of the pollution control projects (PCPs) to control emissions of hazardous air pollutants (HAPs).

The No. 4 Combination Boiler currently is permitted to operate up to a maximum heat input rate of 512.7 million British thermal units per hour (MMBtu/hr) for carbonaceous fuel burning, as a 24-hour average. Based on a nominal heat content of 4,750 British thermal units per pound (Btu/lb), this heat input rate is equivalent to a maximum bark/wood burning rate of 54.0 tons per hour (TPH), as a 24-hour average.

The maximum heat input for the Boiler when firing No. 6 fuel oil is 418.6 MMBtu/hr. Based on a heating value for No. 6 fuel oil of 150,000 British thermal units per gallon (Btu/gal), this heat input rate is equivalent to 2,791 gallons per hour (gal/hr) of fuel oil. The Boiler contains a total of six oil guns.

PM emissions from the No. 4 Combination Boiler are controlled by means of a centrifugal collector, followed by an ESP.

This emissions unit is regulated under Rule 62-296.410, Florida Administrative Code (F.A.C.), Carbonaceous Fuel Burning Equipment; Rule 62-296.404, F.A.C., Kraft Pulp Mills; and 40 CFR, Part 63, Subpart S. This emissions unit is also subject to the requirements of 40 CFR 63, Subpart DDDDD (National Emissions Standards for Hazardous Air Pollutants 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

GP is proposing modifications to the No. 4 Combination Boiler to allow the Boiler to burn an increased amount of bark/wood and to meet the MACT requirements. The Boiler is currently permitted to burn up to 1,296 tons per day (TPD) of bark/wood (at 4,750 Btu/lb minimum heating value). However, historically the Boiler has not been able to achieve this rate due to the bark/wood feeders, limited combustion air supply, and limited ash removal capabilities. For example, during the last 2 years, the maximum bark/wood usage rate for any day was only 1,130 tons.

GP is requesting changes to the No. 4 Combination Boiler in order to increase the actual and permitted amount of bark/wood fuel that can be burned in the Boiler. The changes GP is proposing to the No. 4 Combination Boiler include:

- Upgrading the bark/wood fuel delivery system by replacing worn out feed system parts, replacing the existing bark surge bin, modifying conveyors to accommodate these changes, and installing new air swept bark distributors.

- Installing a new OFA system.
- Installing a new mechanical dust collector to replace the existing cyclones.
- Making changes to the existing ESP used to control PM emissions from the No. 4 Combination Boiler, and potentially utilizing the existing No. 5 Power Boiler ESP as an additional control device. In this case, a new ESP will be installed for the No. 5 Power Boiler.
- Modifying the NCG piping for incorporation into the new OFA system.
- Installing new LNBs for fuel oil firing. The new burners will be of the same capacity and number as the existing burners.

GP is also evaluating installing new baffles for better undergrate air distribution for the No. 4 Combination Boiler. Engineering evaluations are ongoing, and final engineering may dictate that some of these changes will be implemented, while others may not.

As mentioned above, GP is upgrading the OFA system on the Boiler. Such systems have been installed on a number of bark/wood boilers throughout the country, and have resulted in positive improvements to boilers, including increased combustion efficiency and a reduction in the amount of excess air used in a boiler. These systems also decrease emissions of PM, PM_{10}, CO, and VOC on a pound-per-million-British-thermal-unit (lb/MMBtu) basis, while not increasing NO_x emissions on a lb/MMBtu basis. GP has not committed to a specific vendor at this time.

The project will result in an increase in the actual amount of bark/wood fuel burned in the No. 4 Combination Boiler on a short-term basis and an annual average basis. The current permitted maximum hourly bark/wood heat input and burning rates will also be increased as part of this project. The future hourly maximum heat input rate will be 564 MMBtu/hr, equivalent to 59.4 TPH of bark/wood at 4,750 lb/MMBtu. This represents a 10-percent increase over the current permit limit of 512.7 MMBtu/hr. The current permit limit was based on a 24-hour average until January 2005, when FDEP revised the limit to be a 1-hour average (permit no. 1070005-028-AC/PSD-FL-341). In order to regain the ability to achieve a 24-hour average heat input rate of 512.7 MMBtu, the higher hourly limit of 564 MMBtu/hr is necessary.

In order to limit future potential emissions from the No. 4 Combination Boiler, GP is requesting an annual limitation on heat input rate to the Boiler of 4,042,127 million British thermal units per year (MMBtu/yr). This is equivalent to 425,487 tons per year (TPY) wet wood at 4,750 Btu/lb.

The maximum hourly heat input rate when firing No. 6 fuel oil will not be affected by the proposed project. However, it is likely that the project will result in an actual reduction in annual fuel oil usage in the Boiler, since the preferred fuel is bark/wood. GP will maintain the fuel oil sulfur content at 2.35 percent. However, future annual No. 6 fuel oil consumption in the No. 4 Combination Boiler will be limited to 5,100,000 gallons per year (gal/yr) in order to limit the future potential annual sulfur dioxide (SO_2) emissions from the Boiler and avoid PSD review for that pollutant. In addition, GP will install new LNBs to control NO_x emissions while firing fuel oil. The LNBs will have the same heat input capacity and number as the current burners.

As part of the project, GP is also proposing to permanently shut down the No. 4 Power Boiler. The No. 4 Power Boiler is permitted to fire only No. 6 fuel oil.

2.3 Air Emission Estimates and Pollution Control Equipment

PM/PM_{10} emissions from the No. 4 Combination Boiler are currently controlled by mechanical dust collectors and an ESP. GP will replace the existing dust collectors with a new dust collector. In addition, GP is proposing to upgrade the Boiler fuel feed system and OFA system, and to replace the existing fuel oil burners with low-NO_x burners. This upgrade is expected to reduce PM/PM_{10}, CO, and VOC emissions, while not increasing NO_x emissions on a lb/MMBtu basis for bark/wood burning or No. 6 fuel oil burning. The changes will also allow the Boiler to meet the MACT standards for Industrial, Commercial and Institutional Boilers and Process Heaters.

GP is also considering measures to maximize ESP performance. The ESP serving the No. 4 Combination Boiler has three fields. There is no physical room to add another field. However, GP is considering utilizing the No. 5 Power Boiler ESP to act as the fourth, fifth, and sixth fields for the No. 4 Combination Boiler ESP. In this case, GP would install a new ESP for the No. 5 Power Boiler, allowing its existing ESP to become available. The exhaust gases from the No. 4 Combination Boiler ESP would be routed to the No. 5 Power Boiler ESP, and then exhausted to the atmosphere either through the No. 5 Power Boiler stack or through the existing No. 4 Combination Boiler stack.

2.3.1 Past Actual Emissions

The past actual average emissions for 2004 through 2005 from the No. 4 Combination Boiler are presented in Table 2-1. The past actual emissions for the No. 4 Combination Boiler were obtained from the Annual Operating Reports (AORs) submitted to the FDEP for these sources, except for the following differences:

- SO_2 emissions for fuel oil firing were corrected to reflect the equation in the Title V operating permit for the Boiler (see footnote "j" in Table 2-1).

- Past actual NO_x emissions for bark/wood firing were reported in the AORs based on the U.S. Environmental Protection Agency (EPA) Publication AP-42 emission factor (0.22 lb/MMBtu). However, this factor is a general factor and may not be representative of an individual boiler. Very limited test data on the No. 4 Combination Boiler indicates that NO_x emissions in the range of 0.15 to 0.28 lb/MMBtu. These tests were conducted for the purpose of assessing the affects of SOG burning in the No. 4 Combination Boiler. Separate tests conducted in October 2005 indicated NO_x emissions in the range of 0.21 to 0.27 lb/MMBtu, with an average NO_x emission rate of 0.24 lb/MMBtu. Although oil was burned during the six tests, it only accounted for a small percentage as compared to the amount of bark/wood burned. Although limited information is available concerning current NO_x emissions from the Boiler, the calculations use the higher NO_x factor (0.24 lb/MMBtu), uncontrolled for both the current actual and future potential emissions (since no increase in emissions on a lb/MMBtu basis is expected due to the OFA system). This approach results in a greater net increase in NO_x emissions due to the project.

- Past actual NO_x emissions from No. 6 fuel oil firing were reported in the AORs based upon the NO_x factor in AP-42 of 47 lbs/1000 gal, equivalent to 0.31 lb/MMBtu. This factor is reasonable, based on the NO_x test data from the No. 4 Combination Boiler.

- Past actual PM emissions were calculated based on actual fuel oil usage, wood/bark burned, and stack test data (refer also to Table 5-4 in Section 5.0). PM_{10} emissions were estimated at 63 percent of PM for fuel oil and 74 percent of PM for wood/bark for a boiler with an ESP control device. This is based on data presented in AP-42, Section 1.3, Table 1.3-4.

- VOC emissions due to wood/bark burning were based on an updated emission factor of 0.017 lb/MMBtu from AP-42, Section 1.3.

- SAM emissions were not reported in the AORs for the Boiler. Therefore, SAM was calculated based on a derivation from the AP-42, Table 1.3-1, by multiplying the SO_2 emissions by 4.4 percent [3.6 percent of SO_2 becomes sulfur trioxide (SO_3), then taking into account the ratio of SAM and SO_3 molecular weights (98/80)].

- Mercury (Hg) and fluorides (F) emissions were not reported in the AORs. Hg and F emissions were calculated based on the actual amount of fuel oil or wood/bark burned in the No. 4 Combination Boiler. Emission factors for Hg and F while burning fuel oil were obtained from AP-42, Table 1.3-11, and the emission factor for Hg while burning wood/bark was obtained from AP-42, Table 1.6-4. No F emissions were reported in AP-42 for wood/bark burning.

Refer to the footnotes in Table 2-1 for further explanations of these changes.

The past actual short-term emissions for the No. 4 Combination Boiler are presented in Appendix A. Table A-1 summarizes the past actual 24-hour emissions for the highest bark/wood burning day from 2004 through 2005, which was March 11, 2004. Table A-2 summarizes the past actual 24-hour emissions for the highest fuel oil burning day from 2004 through 2005, which was January 17, 2005. Refer to the footnotes in Tables A-1 and A-2 for explanation of the emission factors used to determine the past actual short-term emissions.

The No. 4 Power Boiler will be shut down as part of the proposed project. These emissions are used in the PSD netting analysis (refer to Section 3.0) to determine PSD applicability for the proposed project. The past actual emissions for the No. 4 Power Boiler are also presented in Table 2-1. The No. 4 Power Boiler operated only about 830 hours during 2003. Calendar years 2001 and 2002 were the last years the Boiler operated normally. Therefore, these 2 years were used as the basis of the past actual emissions in the PSD netting analysis.

The past actual emissions for the No. 4 Power Boiler were obtained from the AORs submitted to the FDEP for this source, except for the following differences:

- PM10 emissions for the year 2001 were recalculated based on AP-42, Section 1.3, Table 1.3-5, which provides an equation for industrial boilers with no control device firing No. 6 fuel oil (see footnote "l" in Table 2-1).

- SAM emissions were not reported in the AORs for the Boiler. Therefore, SAM was calculated based on a derivation from EPA Publication AP-42, Table 1.3-1, by multiplying the SO2 emissions by 4.4 percent [3.6 percent of SO2 becomes SO3, then taking into account the ratio of SAM and SO3 molecular weights (98/80)].

- Hg and F emissions were not reported in the AOR. Hg and F emissions were calculated based on the actual amount of fuel oil burned in the No. 4 Power Boiler. Emission factors were obtained from AP-42, Table 1.3-11.

Table A-3 in Appendix A contains the past actual 24-hour emissions for the No. 4 Power Boiler based on the highest fuel oil burning day, which was November 4, 2002. Refer to the footnotes in Table A-3 for explanations of the emission factors used to determine the short-term emissions.

2.3.2 Future Potential Emissions

The future potential annual emissions for the modified No. 4 Combination Boiler are presented in Table 2-2 and Tables B-1 and B-2 of Appendix B. The future potential short-term emissions for the No. 4 Combination Boiler are presented in Tables B-3 and B-4 of Appendix B. In each case, the worst-case fuel mix was determined and used to estimate the maximum emissions.

As discussed above, future annual heat input to the No. 4 Combination Boiler will be limited to 4,042,127 MMBtu/yr to limit the potential emissions from the Boiler. Future No. 6 fuel oil burning will be limited to 5,100,000, gal/yr with a maximum sulfur content of 2.35 percent. The new LNBs will be designed to limit NO_x emissions to 0.27 lb/MMBtu when burning fuel oil. This represents a 15 percent reduction from the past actual emissions of 0.31 lb/MMBtu for No. 6 fuel oil burning.

As described previously, no increase in NO_x emissions due to bark/wood firing is expected on a lb/MMBtu basis due to the new OFA system. The past actual NO_x emissions for bark/wood firing were based on a factor of 0.24 lb/MMBtu, which is based on actual test data.

PM emissions from the No. 4 Combination Boiler will be limited to 0.04 lb/MMBtu, which is much lower than the National Emission Standards for Hazardous Air Pollutants (NESHAPs) promulgated for Industrial, Commercial and Institutional Boilers and Process Heaters (40 CFR 63, Subpart DDDDD) (see Sections 3.3.2 and 3.4.3.2). Subpart DDDDD limits PM emissions to 0.07 lb/MMBtu. The proposed limit is a significant reduction from the current PM limit of 0.3 lb/MMBtu for wood/bark burning and 0.1 lb/MMBtu for fuel oil burning. The proposed emission limit is equivalent to 16.7 lbs/hr and 15.0 TPY for No. 6 fuel oil, and 22.6 lbs/hr and 80.8 TPY for wood/bark-firing (refer to Appendix B for calculations).

In order to meet the lower PM limit, GP will install a new dust collector to replace the existing dust collectors and make improvements to the existing ESP system. This may include utilizing the No. 5 Power Boiler ESP, along with the No. 4 Combination Boiler ESP for PM control for the No. 4 Combination Boiler.

The burning of NCGs, SOGs, and DNCGs in the No. 4 Combination Boiler will not be affected in any manner by the proposed project. The Boiler serves as the backup to the Thermal Oxidizer for the destruction of total reduced sulfur (TRS) and HAPs contained in the NCGs and SOGs. The Boiler will continue to serve in this manner and this part of the process will not be affected by increased operation of the Boiler on bark/wood. The Boiler will continue to serve as the primary destruction device for the DNCGs.

Emissions of SO_2, SAM, TRS, and other pollutants due to NCGs/SOGs/DNCGs burning in the Boiler have been addressed previously through construction permits and PCP exclusions. GP believes that emissions from the Boiler due to NCGs/SOGs/DNCGs destruction should not be included in the determination of PSD applicability for the No. 4 Combination Boiler project, for the following reasons:

- The destruction of NCGs/SOGs/DNCGs is required by federal regulations (40 CFR 63, Subpart S);
- The No. 4 Combination Boiler serves as a control device for the destruction of these gases;
- The process units that generate these gases will be unaffected by the No. 4 Combination Boiler project;
- The Boiler's emissions due to NCGs/SOGs/DNCGs destruction will remain unaffected by the No. 4 Combination Boiler project;
- These emissions have previously been approved through air construction permits and a PCP exclusion from PSD requirements, including a modeling demonstration of compliance with ambient standards and PSD increments;
- Requiring these same emissions to now undergo PSD review would penalize GP for meeting the federal requirements, and negate the effect of the PCP in its entirety; and
- EPA rules or guidance do not contain a specific requirement to include such emissions in the PSD applicability determination.

As a result, emissions due to NCGs/SOGs/DNCGs burning in the No. 4 Combination Boiler have been excluded from both the past actual and future potential emissions for the purpose of determining PSD applicability for the project, as shown in Tables 2-1 and 2-2.

2.4 Effects on Other Emission Units

Only one other emission unit at the GP Palatka Mill may potentially be affected (*i.e.*, increased process rates or increased actual air emission rates) due to the proposed modification of the No. 4 Combination Boiler. Wood chips and bark are supplied to the No. 4 Combination Boiler by the Bark Handling System. Since the actual amount of bark/wood consumed in the Boiler will be increasing as part of this project, the Bark Handling System may be affected by this proposed project.

GP recently obtained a PSD permit for changes to the Bark Handling System, including the installation of a new bark hog (Permit No. 1070005-028-AC/PSD-FL-341). The PSD application was based on the maximum bark/wood processing rate through the Bark Handling System, which is also the maximum rate needed to support the maximum annual bark/wood firing rate of the No. 4 Combination Boiler. Since the maximum permitted annual bark/wood firing rate for the No. 4 Combination Boiler is not increasing due to the proposed project, and since the Bark Handling System has recently undergone PSD review in a separate action with this maximum rate, the Bark Handling System is not considered "affected" by the proposed No. 4 Combination Boiler project.

However, since GP is proposing changes to other sources at the Palatka Mill in the same general timeframe, the FDEP has asked that the following projects be included in the PSD applicability analysis:

- No. 4 Lime Kiln (shell replacement);
- No. 4 Recovery Boiler (tube replacements, air system upgrades, crystallizer, and evaporators); and
- Bark Handling System (various upgrades).

The 2004-2005 past actual and future potential emission calculations for these sources are contained in Appendix C and Appendix D, respectively. The past actual and future potential emissions from the No. 4 Combination Boiler and other projects are summarized in Tables 2-3 and 2-4.

TABLE 2-1
SUMMARY OF PAST ACTUAL ANNUAL EMISSIONS FROM NO. 4 COMBINATION BOILER AND NO. 4 POWER BOILER, GP PALATKA

Source Description	EU ID	Pollutant Emission Rate (TPY)										
		SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM[a]	Lead	Mercury	Fluorides
<u>No. 4 Power Boiler</u>												
2001 Actual Emissions	014	296.2	36.2	3.9	19.8	17.19 [l]	0.22	--	13.0 [m]	0.009	0.000087 [g]	0.029 [g]
2002 Actual Emissions		245.0	31.1	3.3	16.5	14.29	0.19	--	10.8 [m]	0.001	0.000075 [g]	0.025 [g]
Average Actual Emissions		**270.6**	**33.6**	**3.6**	**18.1**	**15.7**	**0.20**	**--**	**11.9**	**0.005**	**0.000081**	**0.027**
<u>No. 4 Combination Boiler</u>	016	--	--	--	--	--	--	--	--	--	--	--
2004 Actual Emissions												
--Fuel Oil Usage		763.6 [j]	102.3	10.9	13.1 [c]	8.2 [c]	0.6	--	33.6 [m]	0.003 [o]	0.00025 [h]	0.081 [h]
--Wood/Bark Usage		33.8	324.2 [b]	810.6	121.6 [d]	90.0 [f]	23.0 [k]	--	1.5 [m]	0.065 [p]	0.0047 [i]	--
--NCG/SOG Burning		281.9	19.1	--	--	--	--	0.47 [n]	12.4 [m]	--	--	--
--Total (Without NCGs/SOG)		**797.4**	**426.5**	**821.5**	**134.6**	**98.2**	**23.6**	**0.0**	**35.1**	**0.07**	**0.005**	**0.08**
2005 Actual Emissions												
--Fuel Oil Usage		813.1 [j]	108.9	11.6	14.0 [c]	8.8 [c]	0.6	--	35.8 [m]	0.003 [o]	0.00026 [h]	0.086 [h]
--Wood/Bark Usage		30.3	291.0 [b]	727.4	49.7 [d]	36.8 [f]	20.6 [k]	--	1.3 [m]	0.058 [p]	0.0042 [i]	--
--NCG/SOG Burning		279.5	16.5	--	--	--	--	0.47 [n]	12.3 [m]	--	--	--
--Total (Without NCGs/SOG)		**843.4**	**399.9**	**739.0**	**63.7**	**45.6**	**21.3**	**0.0**	**37.1**	**0.06**	**0.005**	**0.09**
Average Actual Emissions												
--Total (Without NCGs/SOG)		**820.4**	**413.2**	**780.3**	**99.2**	**71.9**	**22.4**	**0.0**	**36.1**	**0.065**	**0.0047**	**0.084**

TPY = tons per year.

Footnotes:

[a] Not reported on AOR.

[b] NO_x from wood/bark based on 0.24 lb/MMBtu (converted to lb/ton wood/bark by multiplying by 9 MMBtu/ton) and actual wood/bark burning rate (300,219 TPY for 2004 and 269,420 TPY for 2005).

[c] PM based on the actual fuel oil usage (4,351,660 gal/yr in 2004 and 4,633,380 gal/yr in 2005), heat content of fuel oil (150,000 Btu/gal), and actual stack test data (0.03 lb/MMBtu on 1/8/04 and 0.05 lb/MMBtu on 8/18/05).

[d] PM based on the actual wood/bark burned (300,219 TPY in 2004 and 269,420 TPY in 2005), heat content of wood/bark (4,500 Btu/lb), and actual stack test data (0.09 lb/MMBtu on 1/8/04 and 0.041 lb/MMBtu on 8/18/05).

[c] PM_{10} = 63% of PM, which is based on AP-42 Section 1.3, Table 1.3-4, for utility boilers firing residual oil with an ESP. (Note: no factor available for industrial boiler with an ESP).

[f] PM_{10} = 74% of PM, which is based on the ratio of individual emission factors for PM and PM_{10} from AP-42 Table 1.6-1 for wood-residue fired boilers with an ESP (0.054 lb/MMBtu for PM; 0.04 lb/MMBtu for PM10).

[g] Mercury and Fluoride emissions based on actual fuel oil usage (1,323,000 gal/yr for 2002 and 1,540,000 gal/yr for 2001) and emission factors from AP-42 Section 1.3-11 (Hg = 1.13E-04 lb/1000 gal; F = 3.73E-02 lb/1000 gal).

[h] Mercury and Fluoride emissions based on actual fuel oil usage (4,351,660 gal/yr in 2004 and 4,633,380 gal/yr in 2005) and emission factors from AP-42 Section 1.3-11 (Hg = 1.13E-04 lb/1000 gal; F = 3.73E-02 lb/1000 gal).

[i] Mercury based on actual wood/bark burned (300,219 TPY in 2004 and 269,420 TPY in 2005) and emission factor from AP-42 Section 1.6-4 (Hg = 3.5E-06 lb/MMBtu converted to 3.15E-05 lb/ton bark by multiplying by 9 MMBtu/ton).

[j] SO_2 emissions recalculated based on equation in Title V permit: 0.164 x %S x gallons fuel fired / 2000 lbs/ton = tons SO_2

[k] VOC revised based on updated AP-42 factor for wood firing of 0.017 lb/MMBtu; Lead based on 4.8E-05 lb/MMBtu.

[l] Based on AP-42 Section 1.3, Table 1.3-5, for industrial boilers firing residual oil with no PM control device: 7.17*[1.12(%S)+0.37] lb/1000gal.

[m] Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil (Table 1.3-1): 3.6% of SO_2 becomes SO_3 then take into account the

[n] Based on maximum permitted rate for TRS.

[o] Lead emissions based on actual fuel oil usage (4,351,660 gal/yr in 2004 and 4,633,380 gal/yr in 2005) and emission factors from AP-42 Section 1.3-11 (Pb = 1.51E-03 lb/1000 gal).

[p] Lead emissions based on actual wood/bark burned (300,219 TPY in 2004 and 269,420 TPY in 2005) and emission factors from AP-42 Section (Pb = 4.8E-05 lb/MMBtu converted to lb/ton wood/bark by multiplying by 9 MMBtu/ton).

Source: Annual Operating Reports submitted to Florida DEP, unless otherwise noted.

TABLE 2-2
FUTURE POTENTIAL ANNUAL EMISSIONS FOR DIFFERENT FUEL BURNING SCENARIOS, NO. 4 COMBINATION BOILER, GP PALATKA

Source Description	Pollutant Emission Rate (TPY)										
	SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Hg	F
No. 4 Combination Boiler											
--Max Fuel Oil & Wood/Bark Usage	1,023.7	496.5	1,010.5	80.8	59.8	34.4	--	45.0	0.097	0.007	0.095
--NCGs/SOG Burning	785.0	37.8	--	--	--	--	15.7	34.5	--	--	--
--Maximum for Any Fuel (With NCGs/SOG/DNCGs)	**1,808.7**	**534.4**	**1,010.5**	**80.8**	**59.8**	**34.4**	**15.7**	**79.6**	**0.097**	**0.007**	**0.095**
--Maximum for Any Fuel (Without NCGs/SOG/DNCGs)	**1,023.7**	**496.5**	**1,010.5**	**80.8**	**59.8**	**34.4**	**0.0**	**45.0**	**0.097**	**0.007**	**0.095**

TPY = tons per year.

Source: Annual emissions from Tables B-1 and B-2.

TABLE 2-3
PAST ACTUAL ANNUAL (2004-2005) EMISSIONS FOR THE NO. 4 COMBINATION BOILER AND OTHER PROJECTS, GP PALATKA

Source Description	EU ID	Pollutant Emission Rate (TPY)										
		SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluoride
2004 Actual Emissions [c]												
No. 4 Combination Boiler [b]	016	797.4	426.5	821.5	134.6	98.2	23.6	--	35.1	0.068	5.0E-03	0.081
No. 4 Lime Kiln	017	0.04	129.5	5.4	30.4	29.9	2.3	2.3	0.0017	0.160	--	--
No. 4 Recovery Boiler	018	17.4	464.7	1,285.0	213.0	159.8	1.2	8.9	2.4	0.012	6.7E-05	--
No. 4 Smelt Dissolving Tank	019	27.2	56.2	9.3	41.2	37.1	93.1	6.1	--	0.010	6.7E-05	--
Black Liquor/Green Liquor Tanks	042	--	--	--	--	--	9.6	3.0	--	--	--	--
Caustic Area	042	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Bark Handling System (March 2005) [a]	--	--	--	--	14.6	10.6	175.4	--	--	--	--	--
2005 Actual Emissions [c]												
No. 4 Combination Boiler [b]	016	843.4	399.9	739.0	63.7	45.6	21.3	--	37.1	0.062	4.5E-03	0.086
No. 4 Lime Kiln	017	0.04	73.3	8.2	72.1	70.9	2.6	2.8	0.0018	0.160	--	--
No. 4 Recovery Boiler	018	12.0	481.7	1,213.5	56.3	42.2	17.8	13.7	0.53	0.012	6.9E-05	--
No. 4 Smelt Dissolving Tank	019	28.2	58.0	9.5	28.6	25.7	95.7	4.1	--	0.010	6.9E-05	--
Black Liquor/Green Liquor Tanks	042	--	--	--	--	--	9.7	3.0	--	--	--	--
Caustic Area	042	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Bark Handling System (March 2005) [a]	--	--	--	--	14.6	10.6	175.4	--	--	--	--	--
Average 2004 & 2005 Actual Emissions												
No. 4 Combination Boiler	016	820.4	413.2	780.3	99.2	71.9	22.4	--	36.1	0.065	4.7E-03	0.084
No. 4 Lime Kiln	017	0.04	101.4	6.8	51.3	50.4	2.5	2.6	0.0018	0.160	--	--
No. 4 Recovery Boiler	018	14.7	473.2	1,249.3	134.7	101.0	9.5	11.3	1.47	0.012	6.8E-05	--
No. 4 Smelt Dissolving Tank	019	27.7	57.1	9.4	34.9	31.4	94.4	5.1	--	0.010	6.8E-05	--
Black Liquor/Green Liquor Tanks	042	--	--	--	--	--	9.7	3.0	--	--	--	--
Caustic Area	042	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Bark Handling System (March 2005)	--	--	--	--	14.6	10.6	175.4	--	--	--	--	--

[a] Based on PSD Application for Replacement of the Bark Hog, dated July 2004. Emissions did not increase in 2005.

[b] See Table 2-1.

[c] See Appendix C for emission calculations, unless otherwise noted.

TABLE 2-4
FUTURE POTENTIAL ANNUAL EMISSIONS FOR THE NO. 4 COMBINATION BOILER AND OTHER PROJECTS, GP PALATKA

Source Description	EU ID	Pollutant Emission Rate (TPY)										
		SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluoride
Future Potential Emissions												
No. 4 Combination Boiler - 2.35% S [a]	016	1,023.7	496.5	1,010.5	80.8	59.8	34.4	--	45.0	0.097	0.0071	0.095
Other Projects												
No. 4 Lime Kiln: annual: 20 ppmvd TRS	017	40.0	219.8	71.5	130.2	128.0	41.4	25.1	1.80	0.25	--	--
Bark Handling System	--	--	--	0.0	22.8	13.9	475.8	--	--	--	--	--
No. 4 Recovery Boiler [d]	018	153.9	738.1	2,245.6	331.1	248.3	92.0 [c]	34.2	15.9	0.014	8.3E-05	--
No. 4 Smelt Dissolving Tank [b]	019	33.7	69.6	11.4	55.2	49.7	115.0	14.9	--	0.013	8.3E-05	--
Black Liquor/Green Liquor Tanks [b]	042	--	--	--	--	--	14.0	3.7	--	--	--	--
Caustic Area [b]	042	--	--	--	2.6	2.6	18.9	5.8	--	--	--	--

[a] Total future potential emissions from Table 2-2, and Tables B-1 and B-2 (without NCGs, SOG, DNCGs).

[b] Sources will potentially be "affected" as part of the No. 4 Recovery Boiler tube replacement project.

[c] Based on the No. 4 Recovery Boiler permit limit (Draft Permit No. 1070005-035-AC/PSD-FL-367).

[d] Based on the No. 4 Recovery Boiler Draft Permit (Permit No. 1070005-035-AC/PSD-FL-367) and Appendix D.

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 Sections 3.1 through 3.3. The applicability of these regulations to the proposed GP modification is presented in Section 3.4. These regulations must be satisfied before the proposed project 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.

For Kraft pulp mills, a "major facility" is defined as any one of 28 named source categories that has the "potential-to-emit" 100 TPY or more of any pollutant regulated under the CAA. "Potential-to-emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. For an existing source for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emission rates. The PSD significant emission rates are listed in Table 3-2.

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, and memorial parks larger than 5,000 acres and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and nitrogen dioxide (NO_2).

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21 (Prevention of Significant Deterioration of Air Quality). The State of Florida has adopted PSD regulations that are equivalent to the federal PSD regulations (Rule 62-212.400, F.A.C.). 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 unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed 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 significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication *Guideline on Air Quality Models* (EPA, 1980).

To address compliance with AAQS and PSD Class 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 that are used to determine the level of air impact analyses needed for the project. If the new or modified source's impacts are predicted to be less than significant, then the source's impacts are assumed not to have a significant adverse 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. Because the EPA action to officially incorporate Class I significant impact levels into the PSD process will be lengthy, EPA believes that the guidance concerning the significant impact levels is appropriate in the interim to assist states in implementing the PSD permitting 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 weather data from a nearby weather station that represents weather conditions at the project site. The criteria used in this evaluation includes: 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, 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; and
- 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 *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality 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 not cause, in any area, air quality impacts greater than the *de minimis* levels presented in Table 3-2.

3.2.5 Good Engineering Practice Stack Height

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

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). The 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.

3.2.6 Additional Impact Analysis

In addition to air quality impact analyses, federal and State of Florida regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source 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 must also be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.3 Potentially Applicable Emission Standards

3.3.1 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 a "modification" or "reconstruction". "***Modification***" means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

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

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 the No. 4 Combination Boiler.

Federal NSPS also exist for Fossil-Fuel-Fired Steam Generators for which construction or modification occurs 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.

3.3.2 National Emission Standards for Hazardous Air Pollutants

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 Rules, 40 CFR 63, Subpart A, *reconstruction* is defined as follows:

Reconstruction, unless otherwise defined in a relevant standard, means the replacement of components of an affected or previously nonaffected source to such an extent that:

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

3.3.3 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. In addition, Rule 62-296.404 regulates the burning of TRS-containing gases (*i.e.*, NCGs, SOG, etc.) in boilers.

3.4 Source Applicability

3.4.1 Area Classification

The project site is located in Putnam County, which has been designated by EPA and FDEP as an attainment or maintenance area for all criteria pollutants. Putnam County and surrounding counties are designated as PSD Class II areas for all criteria pollutants. The GP Palatka Mill is located within 200 km of three PSD Class I areas – Okefenokee National Wilderness Area (NWA), Wolf Island NWA, and Chassahowitzka NWA.

3.4.2 PSD Review

Pollutant Applicability

The GP Palatka 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 SO_2 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 GP Palatka Mill is summarized in Table 3-3. For the No. 4 Combination Boiler, the future potential and past actual emissions are based on information from Section 2.0. The past actual emissions from the No. 4 Power Boiler are also included in the table, since this source is shutting down as part of this project. As described in Section 2.3.2, the future potential and past actual emissions from the No. 4 Combination Boiler due to destruction of NCGs/SOGs/DNCGs have been excluded from this analysis.

The past actual and future potential emissions from the No. 4 Lime Kiln, the Bark Handling System, the No. 4 Recovery Boiler, the No. 4 Smelt Dissolving Tank, the Black Liquor/Green Liquor Tanks, and the Caustic Area are also included in the table, since these sources will be undergoing modifications or are potentially affected as part of the projects scheduled to take place in the same general timeframe as the No. 4 Combination Boiler project. Although these projects are unrelated to the No. 4 Combination Boiler project, the FDEP has asked GP to include these emission units in the PSD applicability analysis.

As shown near the top of Table 3-3, the increase in emissions due to the combined projects exceeds the significance levels for several PSD pollutants. For these pollutants, the PSD regulations require that all contemporaneous emissions increases and decreases be included in a netting analysis to determine PSD applicability. These emission changes are included in the lower half of Table 3-3. Also presented is the total net increase in emissions, considering the contemporaneous emission changes. As shown at the bottom of Table 3-3, the net increase in emissions exceeds the PSD significant emission rates for NO_x, CO, PM, PM_{10}, VOC, and SAM. Therefore, PSD review applies for these pollutants.

Source Impact Analysis

A source impact analysis was performed for NO_x, CO, and PM_{10}, emissions resulting from the proposed modification. A regional haze analysis was also performed, which evaluated the impacts of visibility reduction in the PSD Class I areas due to the project. This analysis is presented for all the proposed projects in a separate modeling report (refer to No. 4 Recovery Boiler/No. 4 Lime Kiln application being submitted concurrently with this No. 4 Combination Boiler application).

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_x, CO, PM, PM_{10}, VOC, and SAM, 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 and CO can be exempted for this project because, as shown in the separate modeling report, the proposed modification's impacts are predicted to be less than the applicable *de minimis* monitoring concentrations for these pollutants.

Based on the predicted PM_{10} impacts due to the projects, a monitoring analysis is required. There is no PSD *de minimis* concentration for VOC, however, an increase in VOC emissions of 100 TPY or more requires a monitoring analysis for ozone. Since the predicted increase in VOC emissions due to the proposed modification is greater than 100 TPY, a monitoring analysis for ozone is required. These analyses are presented in the separate modeling report (refer to No. 4 Recovery Boiler/No. 4 Lime Kiln application being submitted concurrently with this No. 4 Combination Boiler application).

There are no *de minimis* monitoring concentrations for PM or SAM. Therefore, these pollutants may also be exempt from pre-construction monitoring.

GEP Stack Height Analysis

All existing stacks at the GP facility currently comply with GEP stack height regulations. In addition, no new stacks are proposed as part of this project, except that if the existing No. 5 Power Boiler ESP is used for the No. 4 Combination Boiler, a new ESP and stack would be installed for the No. 5 Power Boiler. In any event, the proposed modification will comply with the GEP stack height regulations.

3.4.3 Emission Standards

New Source Performance Standards

The No. 4 Combination Boiler is not currently subject to any NSPS. The Boiler was originally constructed in 1965, and has not been previously modified or reconstructed per the NSPS definitions.

The Boiler will be undergoing a physical change to the existing fuel oil firing system, by installing new LNBs. However, no increase in the maximum fuel oil firing rate or maximum emissions due to fuel oil firing is proposed as part of the project. As a result, the NSPS will not be triggered by the proposed project with regard to fuel oil firing and associated emission limits.

The Boiler will be undergoing a physical change for the bark/wood burning system, potentially firing more bark/wood on an hourly basis, and potentially increasing actual PM emissions on an hourly basis. Therefore, the proposed project could constitute a "modification", which would subject the No. 4 Combination Boiler to regulation under 40 CFR 60, Subpart Db. For wood-fired units built new, modified or reconstructed after February 28, 2005, the NSPS limit for PM emissions is 0.085 lb/MMBtu. However, GP is proposing to reduce the current PM emission limit on the Boiler to 0.04 lb/MMBtu by installing an improved OFA system on the Boiler, a new dust collector to replace the existing dust collectors, and by upgrading the existing ESP system for additional PM control.

At the proposed PM emission limit, the maximum hourly PM emissions from the Boiler are 22.6 lbs/hr (refer to Appendix B, Tables B-3 and B-4). A summary of historical PM compliance test data for the No. 4 Combination Boiler is shown in Table 5-4. These historic compliance tests were conducted while burning a combination of bark/wood and fuel oil, in order to achieve at least 90 percent of rated heat input capacity during the testing. GP has also conducted three compliance tests while burning fuel oil only. As shown in Table 5-4 in Section 5.0, the three fuel oil tests showed similar results (PM emissions of about 0.04 lb/MMBtu).

Using the results of the compliance tests while burning wood/bark and fuel oil in combination, the PM emissions due to bark/wood firing can only be estimated. These are also shown in Table 5-4 (refer to Section 5.0), and indicate that PM emissions due to bark/wood firing range from 0.027 to 0.128 lb/MMBtu. Statistical analysis indicates that PM emissions due to bark/wood firing only could be as high as 0.185 lb/MMBtu, based on a 99-percent confidence interval.

Based on the historical PM test data, PM emissions from the No. 4 Combination Boiler have been as high as 43.8 lbs/hr. The first run of the most recent test (August 18, 2005) resulted in PM emissions of 25.4 lbs/hr for bark/oil firing. The proposed maximum PM emission rate after the proposed project is implemented is 22.6 lbs/hr. Therefore, the proposed project will not result in an increase in hourly PM emissions, and Subpart Db will not apply.

The emission limits for SO_2 and NO_x under Subpart Db will not apply to the No. 4 Combination Boiler because there are no emission limits for these pollutants for wood/bark firing. Furthermore, neither the fuel oil firing capability, nor the maximum emissions due to fuel oil firing, will increase due to the proposed project. Therefore, the emission limits for fuel oil firing under Subpart Db will not apply.

GP has developed a budget for the proposed project based on internal cost estimates. The total installed capital cost of the modifications to the Boiler is approximately $5,500,000. The term "comparable entirely new facility" would consist of a new boiler with components identical to the repaired boiler. Reconstruction calculations do not include air pollution control equipment. Using previously developed costs for new boilers in Florida, the cost of a new boiler, comparable to the No. 4 Combination Boiler (*i.e.*, 500 MMBtu/hr), would be on the order of $30,000,000, excluding air pollution control equipment. Therefore, the planned modifications represent only about 18 percent of the cost of a new boiler. As a result, reconstruction is not triggered under the NSPS definitions.

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 the No. 4 Combination Boiler 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. The No. 4 Combination Boiler is in the large solid fuel-fired subcategory, and the applicable emission limits for bark/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 9×10^{-6} lb/MMBtu for Hg. The compliance date for existing boilers is September 13, 2007. GP will comply with the applicable standards by the compliance date.

As discussed in the NSPS paragraph of Subsection 3.4.3 above, the planned modifications to the No. 4 Combination Boiler represent only about 18 percent of the cost of a new boiler. As a result, the No. 4 Combination Boiler 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

The No. 4 Combination Boiler is subject to Rules 62-296.404 and 62-296.410, F.A.C. Rule 62-296.404, F.A.C., regulates Kraft Pulp Mills and contains a TRS emission standard for combustion equipment burning TRS gases. Rule 62-296.410, F.A.C., regulates carbonaceous fuel burning equipment and contains standards for opacity and PM. The standards applicable to the No. 4 Combination Boiler are 30-percent opacity (except 40-percent opacity is allowed for up to 2 minutes per hour) and a 0.3 lb PM/MMBtu limit for carbonaceous fuel plus a 0.1 lb PM/MMBtu limit for fossil fuel. The modified No. 4 Combination Boiler will comply with these standards.

TABLE 3-1
NATIONAL AND STATE AAQS, ALLOWABLE PSD INCREMENTS, AND SIGNIFICANT IMPACT LEVELS (µg/m3)

		AAQS			PSD Increments		Significant Impact Levelsd	
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^d	365b	N/A	260b	5	91	0.2	5
	3-Hour Maximum^b	NA	1,300b	1,300b	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
Ozonea	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

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

aOn July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, PM2.5 standards were introduced with a 24-hour standard of 65 µg/m3 (3-year average of 98th percentile) and an annual standard of 15 µg/m3 (3-year average at community monitors). The ozone standard was modified to be 0.08 ppm (157 µg/m3) for 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 µg/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] (μg/m3)
Sulfur Dioxide	40	13, 24-hour
Particulate Matter [PM(TSP)]	25	NA
Particulate Matter (PM10)	15	10, 24-hour
Nitrogen Dioxide	40	14, annual
Carbon Monoxide	100	575, 8-hour
Volatile Organic Compounds (Ozone)	40	100 TPYb
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.
μg/m3 = micrograms per cubic meter.
MWC = Municipal waste combustor
MSW =Municipal solid waste

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

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

TABLE 3-3
CONTEMPORANEOUS AND DEBOTTLENECKING EMISSIONS ANALYSIS AND PSD APPLICABILITY NO. 4 COMBINATION BOILER, GP PALATKA

Source	Pollutant Emission Rate (TPY)										
Description	**SO_2**	**NO_x**	**CO**	**PM**	**PM_{10}**	**VOC**	**TRS**	**SAM**	**Lead**	**Mercury**	**Fluoride**
Future Potential Emissions[a]											
No. 4 Combination Boiler - 2.35% S	1,023.7	496.5	1,010.5	80.8	59.8	34.4	--	45.0	0.097	0.0071	0.095
No. 4 Lime Kiln: annual: 20 ppmvd TRS	40.0	297.4	71.5	130.2	128.0	41.4	25.1	1.8	0.25	--	--
No. 4 Recovery Boiler	153.9	738.1	2,245.6	331.1	248.3	92.0	34.2	15.9	0.014	8.3E-05	--
No. 4 Smelt Dissolving Tank [b]	33.7	69.6	11.4	55.2	49.7	115.0	14.9	--	0.013	8.3E-05	--
Black Liquor/Green Liquor Tanks [b]	--	--	--	--	--	14.0	3.7	--	--	--	--
Caustic Area [b]	--	--	--	2.6	2.6	18.9	5.8	--	--	--	--
Other Projects											
Bark Handling System [c]	--	--	--	22.8	13.9	475.8	--	--	--	--	--
Total- Future Potential	**1,251.3**	**1,601.6**	**3,339.0**	**622.7**	**502.3**	**791.5**	**83.8**	**62.7**	**0.37**	**0.0072**	**0.095**
Past Actual Emissions [d]											
No. 4 Combination Boiler	820.4	413.2	780.3	99.2	71.9	22.4	--	36.1	0.065	0.0047	0.084
No. 4 Lime Kiln	0.04	101.4	6.8	51.3	50.4	2.5	2.6	0.0018	0.16	--	--
No. 4 Recovery Boiler	14.7	473.2	1,249.3	134.7	101.0	9.5	11.3	1.5	0.012	6.8E-05	--
No. 4 Smelt Dissolving Tank [b]	27.7	57.1	9.4	34.9	31.4	94.4	5.1	--	0.010	6.8E-05	--
Black Liquor/Green Liquor Tanks [b]	--	--	--	--	--	9.7	3.0	--	--	--	--
Caustic Area [b]	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Other Projects											
Bark Handling System [c]	--	--	--	14.6	10.6	175.4	--	--	--	--	--
Total- Past Actual	**862.8**	**1,044.9**	**2,045.7**	**336.3**	**267.0**	**326.4**	**25.9**	**37.6**	**0.25**	**0.0049**	**0.084**
Increase Due to Project	**388.5**	**556.7**	**1,293.3**	**286.5**	**235.3**	**465.1**	**57.8**	**25.1**	**0.13**	**0.0024**	**0.011**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0.6	0.1	3.0
Netting Triggered?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No
CONTEMPORANEOUS EMISSION CHANGES											
MACT I Compliance Project (9/00) (Permit nos. 1070005-007-AC and -017-AC) - startup 2002											
--Increase Due to New Thermal Oxidizer	109.7	151.4	8.8	30.7	30.7	9.1	0.89	7.7	--	--	--
--Increase Due to Modified No. 4 Comb. Boiler	548.7	37.8	--	--	--	--	0.47	21.9	--	--	--
--Increase Due to BSW System w/Condensate Treatment	--	--	--	--	--	48.6	58.7	--	--	--	--
--Decrease Due to Existing Thermal Oxidizer	-749.8	-49.5	-0.3	-20.6	-20.6	-3.2	-0.3	-26.9	--	--	--
--Decrease Due to Existing BSW System w/o Condensate Treatment	--	--	--	--	--	-52.1	-62.9	--	--	--	--
--Net Change	-91.4	139.7 [e]	8.5	10.1	10.1	2.4	-3.14	2.7	--	--	--
New Package Boiler (9/02) (Permit No. 1070005-018-AC) - startup Oct. 2002											
--Increase Due to New Package Boiler (EU 044)	0.1	39.4	16.5	1.5	1.5	1.1	--	--	[f]	[f]	[f]
--Decrease from old No. 6 Package Boiler	-0.07	-9.2	-2.1	-0.15	-0.15	--	--	--	[f]	[f]	[f]
--Net Change	0.03	30.20	14.40	1.35	1.35	1.1	--	--	[f]	[f]	[f]
Brown Stock Washer and Oxygen Delignification System (7/04) (Permit No. 1070005-024-AC) - startup Feb. 2006											
--Increase Due to No. 4 Comb. Boiler/No. 5 Power Boiler	236.3	--	0.3	--	--	4.0	17.1	9.5	--	--	--
--Increase Due to' Pulp Storage Tanks	--	--	--	--	--	63.1	9.6	--	--	--	--
--Decrease from existing BSW System, BL Filter, etc.	--	--	--	--	--	-128.5	-77.1	--	--	--	--
--Net Change	236.3 [e]	--	0.3	--	--	-61.4	-50.4	9.5	--	--	--
No. 4 Power Boiler Shutdown (Sep. 2003)	-270.6	-33.6	-3.6	-18.1	-15.7	-0.2	--	-11.9	-0.005	-0.000081	-0.027
Total Contemporaneous Emission Changes	**-362.0**	**-3.4**	**19.6**	**-6.7**	**-4.3**	**-58.10**	**-53.5**	**0.3**	**-0.005**	**-0.000081**	**-0.027**
TOTAL NET CHANGE	**26.5**	**553.3**	**1,312.9**	**279.8**	**231.0**	**407.0**	**4.3**	**25.4**	**0.12**	**0.0023**	**-0.015**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0.6	0.1	3.0
PSD REVIEW TRIGGERED?	No	Yes	Yes	Yes	Yes	Yes	No	Yes	No	No	No

Notes:

[a] No. 4 Combination Boiler potential emissions from Table 2-2, and Tables B-1 and B-2 (without NCGs, SOG, DNCGs). All other sources based on calculations in Appendix D.

[b] Sources will potentially be "affected" as part of the No. 4 Recovery Boiler tube replacement project.

[c] As estimated by FDEP in Technical Evaluation and Preliminary Determination for Bark Hog Replacement PSD, November 2004.

[d] For No. 4 Combination Boiler, based on actual emissions for 2004 and 2005 from Table 2-1 (without NCGs, SOG, DNCGs). For all other sources, based on Table 2-3 and Appendix C.

[e] Pollution Control Projects (PCP) approved for G-P Palatka Mill; excluded from PSD review.

[f] Since project increase does not exceed PSD significant emission rate, netting is not performed for this pollutant.

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, CO, PM, PM_{10}, VOC, and SAM are 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 these pollutants.

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 and CO can be exempted for this project because, as shown in the separate modeling report, the proposed modification's impacts are predicted to be less than the applicable *de minimis* monitoring concentrations for these pollutants.

A monitoring analysis for PM_{10} is required, based on predicted impacts greater than the *de minimis* monitoring concentration. Also, there is no PSD *de minimis* concentration for VOCs; however, an increase in VOC emissions of 100 TPY or more requires a monitoring analysis for ozone. Since the predicted increase in VOC emissions due to the proposed projects is 407 TPY (see Table 3-3), a monitoring analysis for ozone is required. This analysis is contained in Appendix C of the No. 4 Recovery Boiler application.

There are no *de minimis* monitoring concentrations for PM or SAM. Therefore, these pollutants are exempt from the pre-construction monitoring requirement.

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, the No. 4 Combination Boiler is being physically modified. As a result, BACT applies to each pollutant for which the No. 4 Combination Boiler has a net emissions increase as a result of the modification [40 CFR 52.21(j)(3)]. Therefore, PM/PM_{10}, NO_x, CO, VOC, and SAM emissions from the No. 4 Combination Boiler require a BACT analysis. The BACT analysis is presented in the following sections.

5.2 Particulate Matter

5.2.1 Previous BACT Determinations

As part of the BACT analysis, a review was performed of previous PM/PM_{10} BACT determinations for industrial boilers listed in the RACT/BACT/LAER Clearinghouse (RBLC) on EPA's webpage. Since the No. 4 Combination Boiler burns both No. 6 fuel oil and bark/wood, separate searches were conducted for biomass-fired boilers and fuel oil fired boilers. A summary of BACT determinations for biomass-fired industrial boilers from this review is presented in Table 5-1. Determinations issued during the last 10 years are shown in the table. From the review of previous BACT determinations, it is evident that PM/PM_{10} BACT determinations for new biomass-fired industrial boilers have largely been based on cyclone/ESP technology, while wet scrubbers have been less prominent, and only one fabric filter entry. BACT determinations have been in the range of 0.01 to 0.25 lb/MMBtu for PM/PM_{10} emissions.

A summary of BACT determinations for fuel oil fired industrial boilers from this review is presented in Table 5-2. Determinations issued during the last 10 years are shown in the table. From the review of previous BACT determinations, it is evident that PM/PM_{10} BACT determinations for oil-fired industrial boilers have been primarily based on good combustion practices. Baghouses or wet scrubbers have also been determined as BACT in a few cases. BACT determinations have been in the range of 0.023 to 0.125 lb/MMBtu for PM/PM_{10} emissions.

5.2.2 Control Technology Feasibility

The technically feasible PM/PM_{10} controls for the No. 4 Combination Boiler are listed in Table 5-3. As shown, there are six primary types of PM/PM_{10} abatement methods, with various techniques within each method. Each available technique is listed with its associated control efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency. Also shown are those techniques which will be employed on the modified No. 4 Combination Boiler.

5.2.3 Potential Control Method Descriptions

Fuel Techniques

Fuel Substitution, or fuel switching, is a common means of reducing emissions from combustion sources, such as electric utilities and industrial boilers. It involves replacing the current fuel with a fuel that emits less of a given pollutant when combusted.

For fuel substitution to be practical there must be a suitable replacement fuel available at an acceptable cost. GP's primary fuel for the No. 4 Combination Boiler is bark/wood, which is a co-product of the Mill's wood processing operations. In addition, this project is being implemented to support a reduced dependence on fuel oil by burning an increased amount of bark/wood. Therefore, substitution of the fuel would negate the purpose of the project, and thus was not considered further.

Pretreatment Devices

The performance of PM control devices can often be improved through pretreatment of the gas stream. For PM control devices, pretreatment consists of the following techniques:

- Settling chambers;

- Elutriators;
- Momentum separators;
- Mechanically aided separators; and
- Cyclones.

Of these five techniques, cyclones offer the highest control efficiency, typically in the range of 60 to 90 percent. All of the other techniques have control efficiencies less than 30 percent.

Cyclones use inertia to remove particles from a spinning gas stream. Within a cyclone, the gas stream is forced to spin within a usually conical-shaped chamber. The gas spirals down the cyclone near the inner surface of the cyclone tube. At the bottom of the cyclone, the gas turns and spirals up through the center of the tube and out the top of the cyclone.

Particles in the gas stream are forced toward the cyclone walls by centrifugal forces. For particles that are large, typically greater than 10 microns, inertial momentum overcomes the fluid drag forces so that the particles reach the cyclone walls and are collected. For smaller particles, the fluid drag forces are greater than the momentum forces and the particles follow the gas out of the cyclone. Inside the cyclone, gravity forces the large particles down the sidewalls of the cyclone to a hopper where they are collected.

A cyclone is currently employed on the No. 4 Combination Boiler ahead of the ESP. GP will continue to use a mechanical cyclone in the future on the Boiler, and is planning to replace the existing cyclones with a new cyclone.

Electrostatic Precipitators

Collection of PM by ESPs involves the ionization of the gas stream passing through the ESP; the charging, migration, and collection of particles on oppositely charged surfaces; and the removal of particles from the collection surfaces. There are two basic types of ESPs – dry and wet. In dry ESPs, the PM is removed by rappers, which vibrate the collection surface, dislodging the material and allowing it to fall into the collection hoppers. Wet ESPs use water to rinse the particulates off of the collection surfaces.

ESPs have several advantages when compared with other control devices. They are very efficient collectors, even for small particles, with greater than 97 percent control efficiency. ESPs can also treat large volumes of gas with a low-pressure drop. ESPs can operate over a wide range of temperatures and generally have low operating costs. The disadvantages of ESPs are large capital costs, large space requirements, and difficulty in controlling particles with high resistivity.

The No. 4 Combination Boiler currently employs a cyclone followed by a dry ESP to control PM/PM_{10} emissions. GP will continue to use the existing ESP in the future for PM/PM_{10} control on the Boiler, and may add additional ESP fields by utilizing the No. 5 Power Boiler ESP, as described in Subsection 5.2.5.

Fabric Filters

Baghouses, or fabric filters, utilize porous fabric to clean an airstream. There are several types of baghouses, including reverse-air, shaker, and pulsejet baghouses. The dust that accumulates on the surface of the filter aids in the filtering of fine dust particles. PM/PM_{10} control efficiencies for fabric filters are typically greater than 99 percent.

During fabric filtration, flue gas is sent through the fabric by forced-draft fans. The fabric is responsible for some filtration, but more significantly it acts as support for the dust layer that accumulates. The layer of dust, also known as the filter cake, is a highly efficient filter, even for submicron particles. Woven fabrics rely on the filtration of the dust cake much more than felted fabrics.

Fabric filters offer high efficiencies and are flexible to treat many types of dusts and a wide range of volumetric gas flow rates. In addition, fabric filters can be operated with low pressure drops. Some potential disadvantages are:

- High moisture gas streams and sticky particles can plug the fabric and bind to the filter, requiring bag replacement;
- High temperatures can damage fabric bags; and
- Fabric filters have a potential for fire or explosion due to the carryover of combustible fly ash.

There is only one known application of a baghouse to control PM/PM_{10} emissions from a biomass-fired industrial boiler (see Table 5-1). In addition, there is only one known application of a baghouse to control PM/PM_{10} emissions from a fuel oil-fired industrial boiler (see Table 5-2). The limited application of baghouses on boilers indicates that the technology is unproven. Serious concerns exist over the ability of a baghouse to operate long term in a harsh environment, on flue gas containing significant moisture and "stringy" bark/wood particles, and with potential fire hazards due to burning particles being carried out of a boiler. This is the nature of biomass boilers in the wood products industry. Fabric filters, either alone or in combination with multiclones, are considered technically infeasible due to the heightened fire hazards and their unproven nature.

Wet Scrubbers

Wet scrubbers are systems that involve particle collection by contacting the particles to a liquid, usually water. The aerosol particles are transferred from the gaseous air stream to the surface of the liquid by several different mechanisms. Wet scrubbers create a liquid waste that must be treated prior to disposal. PM/PM_{10} control efficiencies for wet scrubbing systems range from about 50 to 95 percent, depending on the type of scrubbing system used. Typical types of wet scrubbers are as follows:

- Spray chamber,
- Packed-bed,
- Impingement plate,
- Mechanically aided,
- Venturi,
- Orifice, and
- Condensation.

The advantages of wet scrubbers compared to other PM collection devices are that they can collect flammable and explosive dusts safely, absorb gaseous pollutants, and collect mists. Scrubbers can also cool hot gas streams. The disadvantages are the potential for corrosion and freezing, the potential of water and solid waste pollution problems, and high energy costs.

Wet scrubbers are technically feasible for application to the No. 4 Combination Boiler.

Mist Eliminators

The performance of PM control devices can often be improved through the addition of mist elimination. For PM control devices, mist elimination consists of the following techniques:

- Fiber bed,
- Chevron, and
- Mesh pad.

Fiber bed mist eliminators are used to control aerosol emissions from chemical, plastics, asphalt, sulfuric acid, and surface coating industries. They are also used to control lubricant mist emissions from rotating machinery and mists from storage tanks. They are also applied downstream of other control devices to eliminate a visible plume. Despite their potential for high collection efficiency, fiber-bed mist eliminators have had only limited commercial acceptance for dust collection because of their tendency to become plugged, and they have not been demonstrated on biomass-fired boilers. Therefore, they were not considered further.

Chevron mist eliminators and mesh pads are both devices that are used following wet scrubbers to remove water droplets and mist that have been entrained in the gas stream. They can also be used downstream of processes that generate liquid aerosols and mists.

Chevron mist eliminators consist of flat plates set at angles that create sharp changes in direction of the gas flow path. Gas flows upward through the Chevron mist eliminator, while the entrained liquid collects on the plates. The collected droplets increase in number, coalesce, and grow in size until they are large enough to fall back down into the packing. Both the thickness and the number of plates can be varied to obtain the desired degree of removal.

The mesh pad mist eliminator consists of an open-weave blanket of knitted thermoplastic or wire mesh. While the flue gas flows upward through the mist eliminator, entrained liquid collects on the mesh. As the collected droplets increase in number, they coalesce and grow in size. When large enough, the droplets fall back down into the collector. The mesh pad can be flushed periodically to remove trapped particles and to prevent plugging of the pad.

Chevron mist eliminators and mesh pads are devices that are used following wet scrubbers on boilers. Since the No. 4 Combination Boiler will not use a wet scrubber, mist eliminators would not be effective, and therefore were not considered further.

5.2.4 Environmental and Energy Impacts

As shown in a separate modeling report, the maximum predicted PM_{10} impacts due to the proposed projects and the GP facility are less than the AAQS and the PSD Class II and I increments. Additional PM controls would not result in a significant reduction in ambient impacts.

The No. 4 Combination Boiler will employ a new mechanical cyclone and a highly effective ESP control device. The ESP has relatively low energy usage and creates no liquid waste stream. Fly ash collected in the cyclones is reinjected into the Boiler, while the ash collected by the ESP is sent to an ash pond. The ESP device creates the lowest environmental and energy impacts compared to other technologies, which would create liquid waste streams and use more energy.

5.2.5 BACT Selection

Based on the preceding analysis and Table 5-3, the ESP control device achieves the highest reduction in PM emissions of any of the feasible control technologies. A fabric filter can achieve equivalent emission reduction, but the fabric filter was determined to be technically infeasible due to lack of operating experience on biomass-fired boilers and potential operating difficulties and fire potential. Wet scrubbers cannot achieve any higher degree of PM reduction than ESPs. Therefore, wet scrubbers were not considered further.

The changes proposed for the No. 4 Combination Boiler, including improvements to the OFA system and a new under fire air system (which GP is currently evaluating), will improve combustion efficiency. The new air system will allow more bark to be burned on the grate of the Boiler, and carryover of PM out of the Boiler will be reduced. These changes are predicted to result in a reduction in PM/PM_{10} emissions on a lb/MMBtu basis.

GP will implement several additional measures to reduce PM emissions. The first involves the ESP system serving the Boiler. The ESP serving the No. 4 Combination Boiler has three fields. There is no physical room to add another field. However, GP is evaluating the utilization of the No. 5 Power Boiler ESP as additional fields for the No. 4 Combination Boiler ESP. GP may install a new ESP to serve the No. 5 Power Boiler, and, if so, the existing No. 5 Power Boiler ESP may be available under this scenario. GP would route the No. 4 Combination Boiler exhaust gases from its ESP to the existing No. 5 Power Boiler ESP. The exhaust gases would exit to the atmosphere through either the No. 5 Power Boiler stack or the No. 4 Combination Boiler stack.

Since the first two fields of the No. 4 Combination Boiler ESP have experienced some plate warping, these will be repaired to maximize ESP power output. GP will also implement better controls on the ESP to optimize the rapping rates.

Finally, GP will replace the existing cyclone collectors serving the No. 4 Combination Boiler with a new cyclone collector (located between the Boiler and the ESP). All of these changes will result in a reduction in PM/PM_{10} emissions on a lb/MMBtu basis, and will achieve more consistent ESP operation.

The proposed BACT for PM/PM_{10} emissions from the No. 4 Combination Boiler is based on the expected performance of the new mechanical cyclone followed by the ESP. The existing ESP is currently achieving total PM emissions in the range of 0.03 to 0.10 lb/MMBtu, based on historic compliance testing (refer to Table 5-4). Statistical analysis indicates that total PM emissions could be as high as 0.14 lb/MMBtu, based on a 99-percent confidence interval. These historic compliance tests were conducted while burning a combination of bark/wood and fuel oil, in order to achieve at least 90 percent of rated heat input capacity during the testing.

GP has conducted three compliance tests while burning fuel oil only. As shown in Table 5-4, these tests showed similar results (PM emissions of about 0.04 lb/MMBtu). Using the average of the results of the fuel oil tests, the PM emissions due only to bark/wood firing can be estimated. The results are also shown in Table 5-4 and indicate PM emissions due solely to bark/wood firing ranging from 0.027 to 0.128 lb/MMBtu. Statistical analysis indicates that PM emissions could be as high as 0.185 lb/MMBtu for bark/wood firing only, based on a 99-percent confidence interval.

The proposed BACT emission limit for PM emissions from the No. 4 Combination Boiler is 0.04 lb/MMBtu for No. 6 fuel oil, equivalent to 16.7 lbs/hr and 15.0 TPY, and 0.04 lb/MMBtu for bark/wood, equivalent to 22.6 lbs/hr and 80.8 TPY (refer to Section 2.0 and Appendix B for calculations). The proposed BACT emission limit is based on the emission rate considered achievable by the improved OFA system, the combination of mechanical cyclones followed by an ESP, and taking into consideration the fact that the Boiler is an existing unit. Although new units have been permitted with PM emission rates as low as 0.02 lb/MMBtu, the modified No. 4

Combination Boiler may not be able to achieve as low an emission rate due to its inherent limitations as an existing source.

5.3 Nitrogen Oxides

5.3.1 Previous BACT Determinations

As part of the BACT analysis, a review was performed of previous BACT determinations for similar biomass-fired industrial boilers listed in the RBLC on EPA's web page. From this information, BACT determinations issued within the last 10 years were identified. A summary of these BACT determinations is presented in Table 5-5.

Previous BACT determinations for NO_x emissions at similar facilities have ranged from 0.14 to 0.40 lb/MMBtu. From the previous BACT determinations, it is evident that NO_x BACT determinations for new biomass-fired industrial boilers have typically been based on selective non-catalytic reduction (SNCR), good combustion practices, LNBs, or no emission controls. The lowest BACT determination of 0.14 lb/MMBtu was for a new bagasse-fired boiler. Bagasse has a high moisture content, which suppresses NO_x emissions, making a lower limit achievable. The next lowest BACT emission limit is 0.15 lb/MMBtu, which has been determined for several facilities.

A summary of BACT determinations for fuel oil-fired industrial boilers from this review is presented in Table 5-6. Determinations issued during the last 10 years are shown in the table. From the review of previous BACT determinations, it is evident that NO_x BACT determinations for oil-fired industrial boilers have been primarily based on good combustion practices and LNBs. BACT determinations have been issued in the range of 0.37 to 0.70 lb/MMBtu for NO_x emissions.

5.3.2 Control Technology Feasibility

The technically feasible NO_x controls for the No. 4 Combination Boiler are shown in Table 5-7. 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 the No. 4 Combination Boiler will employ the specific technique.

5.3.3 Potential Control Method Descriptions

Removal of Nitrogen

Ultra-Low Nitrogen Fuel – The fuels combusted in the Boiler will be primarily wood/bark. Combustion of this fuel results in inherently low emissions of NO_x (compared to more conventional fuels) due to the characteristically low levels of nitrogen and a high level of moisture associated with wood/bark fuel. GP will control NO_x emissions from the Boiler through the use of low-nitrogen content fuels.

Chemical Reduction of NOx

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. Although SCR is not known to have been previously applied to a biomass-fired boiler, at least one vendor, FuelTech, is willing to offer a quotation for a hybrid SNCR/SCR system. Therefore, SCR is a technically feasible control technique for the Boiler.

Notwithstanding FuelTech's quotation, a number of issues still remain with application of SCR to the No. 4 Combination Boiler. Access, flue gas temperature, and flue gas velocity are important considerations in the location of the SCR reactor. The least expensive scenario is when the reactor vessel can be located in an expanded section of the duct between the economizer outlet and air preheater (APH) inlet where structural support and maintenance access already exist. The location, if a conventional catalyst is used, requires that the flue gas temperature be no greater than 780 degrees Fahrenheit (°F) and not lower than about 570°F.

If the SCR reactor can be located in the flue gas stream where the 570 to 780°F (nominal) temperature is available, no preheat is required. There are high-temperature (>800°F) and low-temperature (250 to 650°F) catalysts, but the high-temperature catalysts are much more expensive than conventional catalysts and the low-temperature catalysts are a "dense pack" design that require prior flue gas cleanup. This usually means reheating the flue gas, which is rarely a cost-effective approach.

An important consideration is flue gas velocity through the SCR catalyst. The exhaust duct must be expanded to provide the flue gas velocity dictated by the catalyst vendor, which will be approximately 20 feet per second (ft/s) depending on the fuel.

Another key consideration is added pressure drop across the SCR reactor. The pressure drop due to the catalyst is about 1 to 1.5 inches water (H_2O), but there will be additional pressure drop due to the reconfigured duct and the addition of a static mixing device.

The economics of the hybrid SNCR/SCR system are affected by whether SNCR chemical (urea) can be released at a lower temperature than what is dictated by the ammonia slip restriction on the SNCR process. Chemical utilization and NO_x reduction are improved at a slightly increased urea injection rate. The SNCR process functions at a higher point on the efficiency curve and the resulting higher, controlled rate of ammonia slip is absorbed in the catalyst bed. The SCR reagent comes from unreacted ammonia leaving the SNCR process.

The SCR catalyst design and therefore life expectancy, is based on the ash loading, expected deactivation rate, etc., as dictated by the flue gas constituents. The catalyst design takes into account the ash loading and the expected contaminants in the flue gas.

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

There are several forms of SNCR are presently being marketed by vendors. The traditional form, and the one with by far the most operating experience, marketed by FuelTech, is designed to inject urea or ammonia into the furnace via injectors penetrating the furnace walls. Injectors are located at several levels in the furnace to provide proper injection over a range of boiler loads. SNCR by FuelTech has been demonstrated as a feasible technology for biomass combustion and can achieve NO_x reductions up to 50 percent.

Another form of SNCR, marketed by Ecotube with their overfire air system, utilizes an air injection system consisting of a lance tube and carriage assemblies. The lance tube(s) is positioned in the furnace above the grate to provide high pressure air, which induces mixing for improved combustion. The tube can be retracted as needed for maintenance or adjustment. Urea can be injected into the tube for additional NO_x control. There is limited experience with this technology.

Still another form, similar to Ecotube, is marketed by Mobotech USA with their overfire air system. Instead of a lance tube, this technology utilizes high velocity air nozzles to inject air, and if desired, urea or ammonia, into the furnace at several levels. Mobotech experience on industrial boilers is limited.

The traditional form of SNCR is currently in operation on three wood/bagasse-fired boilers at New Hope Power Partnership (NHPP) and one bagasse-fired boiler at the United States Sugar Corporation Clewiston Mill (USSC). The NO_x limit issued for a recent modification of the NHPP boilers was 0.15 lb/MMBtu. The limit for the new bagasse-fired boiler at USSC is 0.14 lb/MMBtu.

Even with these demonstrated projects, there still remain concerns over ammonia slip and unreacted urea impinging on the boiler tubes and causing premature boiler tube failure and other effects on downstream equipment (i.e., air heater, superheater, etc.), and associated maintenance/repair costs. This is especially true in a retrofit situation such as the No. 4 Combination Boiler, where the SNCR system cannot be designed optimally due to the existing boiler configuration. As a result, the SNCR system must be carefully designed (i.e., control efficiency limited) in order to maintain ammonia slip at acceptable levels.

Based on the above discussion, SNCR is considered to be technically feasible for the proposed modification of the No. 4 Combination Boiler.

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. The No. 4 Combination Boiler will utilize OFA, 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 nitrogen (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, which 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 generated, but can adversely increase CO emissions. A NO_x reduction of 15 percent is estimated with a flue gas recirculation (FGR) system. However, an FGR system has not been employed in combination with an OFA system on a biomass boiler. Therefore, the performance of this combined technology is unknown and could result in high CO emissions, which is a concern for the No. 4 Combination Boiler. Regardless, the FGR technology alone is considered technically feasible.

Reburn – 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. NO_x, created by the combustion process in the main portion of the boiler, drifts upward into the reburn zone and is converted to N_2. The technology requires no catalysts, chemical reagents, or changes to any existing burners. Typical reburn systems also incorporate redesign of the combustion air system along with the water-cooled, pinhole grate to provide less excess air (LEA). Natural gas reburn is a feasible technology for the No. 4 Combination Boiler.

Over-Fire Air – When primary combustion uses a fuel-rich mixture, the use of OFA completes the combustion. Because the mixture is always off-stoichiometric when combustion is occurring, the temperature is reduced. After all other stages of combustion, the remainder of the fuel is oxidized in the OFA. The modified No. 4 Combination Boiler will utilize an improved OFA system to maximize combustion efficiency and reduce NO_x emissions.

Less Excess Air – Excess airflow combustion has been correlated to the amount of NO_x generated. Limiting the net excess airflow can limit the NO_x content of the flue gas. The modified No. 4 Combination Boiler will utilize a combustion system that minimizes the amount of excess air in the furnace.

Combustion Optimization – Combustion optimization refers to the active control of combustion. The active combustion control measures seek to find optimum combustion efficiency and to control combustion at that efficiency. The modified No. 4 Combination Boiler will be optimized for maximum combustion efficiency, considering the constraints on the existing systems.

<u>Low-NO_x Burners</u> – 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 systems with a 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. LNB is, however, feasible for No. 6 fuel oil burning in the No. 4 Combination Boiler.

As shown in Table 5-6, the NO_x emission limits for LNBs as applied to No. 6 fuel oil burning are high. Indeed, burner manufacturers state that LNBs for No. 6 fuel oil generally achieve very little NO_x reduction. However, GP is planning to install LNBs on the No. 4 Combination Boiler to achieve the lowest, cost-effective NO_x emissions from the Boiler.

5.3.4 <u>Economic Analysis</u>

The modified No. 4 Combination Boiler will utilize an improved OFA system to optimize combustion; generate more steam; burn more bark/wood; and reduce emissions of PM, CO, and VOCs. Based on the OFA system vendors GP is considering, NO_x emissions will not increase on a lb/MMBtu basis, with the improved OFA system. One OFA system, marketed by Mobotec USA, could provide substantial NO_x emission reduction (up to 50 percent reduction). However, their system was not considered further because the system could not meet GP's performance requirements for steam production and bark/wood burning rate.

The hierarchy of NO_x control options, based on the options presented in Table 5-7, starting with the top control efficiency option, is as follows:

- Hybrid SNCR/SCR system achieving 65-percent NO_x reduction on bark/wood and 40 percent reduction on fuel oil;
- Ecotube system with urea injection achieving 60-percent NO_x reduction on bark/wood and 40-percent for No. 6 fuel oil;
- SNCR system achieving 35-percent NO_x reduction on bark/wood and 25 percent on fuel oil;

- Ecotube system without urea injection achieving 20-percent NO_x reduction on bark/wood and fuel oil;
- Reduce time at peak temperature;
- Reducing peak temperature;
- FGR system achieving 15-percent NO_x reduction for bark/wood firing;
- LNBs achieving 15-percent NO_x reduction for fuel oil firing;
- Using low nitrogen fuel (i.e., bark/wood).

Of these nine options, GP proposes to utilize four of these in the No. 4 Combination Boiler. These include reducing time at peak temperature; reducing peak temperature; LNBs for No. 56 fuel oil burning; and, using low-nitrogen fuel (bark/wood). An economic analysis was performed for the remaining five options.

The baseline emissions used for the NO_x cost effectiveness analysis is 0.24 lb/MMBtu for bark/wood firing and 0.31 lb/MMBtu for fuel oil firing (AP-42 emission factor for normal firing without LNBs). These emission levels are based on actual testing of the No. 4 Combination Boiler under different fuel-firing scenarios as well as AP-42 emission factors, and reflect the best estimate of current NO_x levels. An annual capacity factor of 80 percent was used for the baseline emissions, since this is the historic capacity factor for the No. 4 Combination Boiler. The annual capacity factor in the future is not expected to increase, although more bark/wood will be burned on an annual basis. Also, SOG burning in the Boiler was not considered in the baseline emissions since the Boiler is only used as a backup control device to the Thermal Oxidizer.

The economic analysis of the SNCR/SCR hybrid option is presented in Table 5-8. The analysis assumes a 3-year catalyst life. The total installed capital cost is estimated at $8,100,000. The total annual operating cost is estimated at $1,800,000. Based on the NO_x reduction potential of the system of 65 percent for bark/wood and 40 percent for fuel oil, the cost effectiveness is $6,457 per ton of NO_x removed.

Although this cost effectiveness is within the range that has been determined to be cost effective for sources such as electric utility gas turbines, it is higher than the cost effectiveness that has been determined to be economically infeasible for existing industrial boilers in Florida. In addition, there is significant uncertainty regarding the actual capital cost of the system, the performance of the system (i.e., catalyst life, maintenance, etc.), and the actual NO_x reduction that will be achieved, due to the lack of operating experience on industrial biomass-fired boilers. As a result, the SNCR/SCR hybrid system is eliminated from further consideration.

The economic analysis of the Ecotube system option is presented in Table 5-9. The total installed capital cost is estimated at $4,000,000 for the "air-only" system and $5,500,000 for the system with urea injection. The total annual operating cost is estimated at $860,000 for the air-only system and $1,287,000 for the system with urea injection. Based on the NO_x reduction potential of the air-only system of 20 percent overall, and for the urea injection system of 60 percent for bark/wood and 40 percent for fuel oil, the cost effectiveness is $9,752 per ton of NO_x removed for the air-only system, and $4800 per ton for the urea injection system. Although the cost effectiveness for the urea injection system is within the range that has been determined to be cost effective for sources such as electric utility gas turbines, it is higher than the cost effectiveness which has been determined to be economically infeasible for existing industrial boilers in Florida.

The economic analysis of the FuelTech SNCR system option is presented in Table 5-10. The total installed capital cost is estimated at $3,400,000, and the total annual operating cost is estimated at $717,500. Based on the NO_x reduction potential of the SNCR system of 30 percent overall, the cost effectiveness is $5,419 per ton of NO_x removed. Although the cost effectiveness is within the range which has been determined to be cost effective for sources such as electric utility gas turbines, it is higher than the cost effectiveness that has been determined to be economically infeasible for existing industrial boilers in Florida.

The economic analysis of the FGR system option is presented in Table 5-11. The total installed capital cost is estimated at $2,100,000, and the total annual operating cost is estimated at $347,000. Based on the NO_x reduction potential of the FGR system of 15 percent for bark/wood firing only, the cost effectiveness is $5,374 per ton of NO_x removed. Although the cost effectiveness is within the range that has been determined to be cost effective for sources such as electric utility gas turbines, it is higher than the cost effectiveness that has been determined to be economically infeasible for existing industrial boilers in Florida. More importantly is the unknown increase in CO emissions that will potentially be encountered due to the FGR system in combination with the OFA system that GP is planning to upgrade. Although technically feasible as a single reduction strategy, the FGR system and OFA system together may not meet GP's needs of reducing CO emissions as well as NO_x.

A study performed by NCASI in August 2003 (Special Report No. 03-03) reports that the EPA suggests the use of $2,000 per ton of NO_x removed as the criteria to determine what is considered economically feasible. Based on the economic analysis presented herein for these add-on control technologies, all result in considerably higher cost effectiveness than $2,000 per ton. As a result, all are considered economically infeasible.

5.3.5 Environmental and Energy Impacts

As shown in Attachment C of the No. 4 Recovery Boiler/No. 4 Lime Kiln application, the maximum predicted NO_2 impacts for the proposed project are less than the AAQS and EPA Class II and I PSD increments. Additional NO_x controls would result in an insignificant reduction of ambient impacts that are already only slightly above the EPA significance levels for both Class I and II areas.

Energy penalties occur with the hybrid SNCR/SCR system, the Ecotube with urea injection system, and with the SNCR only NO_x control systems. Additional energy, water, and ammonia are all required for these systems.

5.3.6 BACT Selection

For the No. 4 Combination Boiler, the combination of good combustion practices, LNBs, OFA, and low nitrogen-content fuel (biomass), can achieve the maximum amount of emissions reduction that is technically and economically feasible, and that is demonstrated in practice. Additional controls should be rejected as BACT for the No. 4 Combination Boiler for the following reasons:

- All five alternative control technologies for which an economic analysis was performed have very high capital and annual operating cost (i.e., greater than $2 million and $300,000, respectively), resulting in a cost effectiveness of over $4,800 per ton of NO_x removed.

- SNCR has not been demonstrated in practice on an older, existing, 100-percent biomass-fired boiler and operating in a harsh environment. Serious concerns are related to achieving the proper temperature window and residence time for reaction of the urea, as well as ammonia slip and unreacted urea impinging on boiler tubes and causing premature boiler tube failure and other effects on downstream equipment (i.e., air heater, superheater, etc.), and associated maintenance/repair costs. This is a retrofit situation, where the SNCR system cannot be designed optimally due to boiler configuration, the limited residence time for urea to react, changing temperatures in the boiler, etc. These technical uncertainties and the high cost render this technology infeasible for the No. 4 Combination Boiler.

- SCR has not been demonstrated in practice on a 100-percent biomass-fired boiler and operating in a harsh environment. Serious concerns are related to achieving the proper temperature window and residence time for reaction, catalyst fouling and plugging, and catalyst life and effectiveness. This is a retrofit situation, where the SCR system cannot be designed optimally due to boiler configuration, the limited residence time for reaction, changing temperatures in the boiler, etc. These technical uncertainties and the high cost render this technology infeasible for the No. 4 Combination Boiler.

- FGR has not been demonstrated in practice operating with an OFA system without experiencing increased CO emissions.

The No. 4 Combination Boiler is bark/wood and No. 6 fuel oil-fired. GP is planning to upgrade the OFA system and installing LNBs for fuel oil firing. These upgrades will improve combustion efficiency and reduce potential NO_x emissions.

The proposed BACT for NO_x is the use of good combustion practices, LNBs, OFA, and low nitrogen content fuels (wood/bark and limiting annual No. 6 fuel oil usage). The No. 4 Combination Boiler does not currently have an emission limit for NO_x, but the maximum NO_x emissions are expected to be 0.24 lb/MMBtu, equivalent to 485 TPY when firing wood/bark, and 0.27 lb/MMBtu, equivalent to 101 TPY with LNBs for firing fuel oil, and total annual emissions of 496.5 TPY based on the worst case fuel mix.

5.4 Carbon Monoxide

5.4.1 Previous BACT Determinations

As part of the BACT analysis, a review was performed of previous CO BACT determinations for industrial boilers listed in the RBLC on EPA's web page. A summary of the BACT determinations for biomass-fired industrial boilers from this review is presented in Table 5-12. The CO emission limits for biomass-fired industrial boilers identified in the RBLC search range from 0.03 to 2.25 lbs/MMBtu. This rather large range of emissions is due to differences in boiler design and operation, as well as differences in fuel. From the review of previous determinations, it is evident that CO BACT determinations for biomass-fired industrial boilers have all been based on good combustion practices and boiler design.

5.4.2 Control Technology Feasibility

The technically feasible CO controls for the No. 4 Combination Boiler are shown in Table 5-13. There are four types of CO abatement methods. Each available technique was listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency.

5.4.3 Potential Control Method Descriptions

Good Combustion Practices

Boiler design generally provides a moderately high temperature with sufficient turbulence and residence time at that temperature to complete combustion of the fuel. Good combustion practices maintain efficient combustion and minimize products of incomplete combustion. To ensure good combustion, process monitors can be used to monitor the oxygen (O_2) content of boiler flue gas. Real-time data is fed to the boiler control room. The boiler operator uses the real-time data to adjust the boiler operation to ensure sufficient excess air levels. Good combustion practices are proposed for the No. 4 Combination Boiler.

Incinerators

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

Combustion Modification – OFA

The main combustion modification technique for reducing CO emissions is the use of an OFA system. The reduction in CO emissions realized from this technique is highly dependent upon the uncontrolled CO concentration, combustion chamber oxygen content, air distribution (*e.g.*, portion of the air introduced through the burners versus through the OFA ports), and type and method of fuel being fired. The use of an OFA system ensures that complete combustion takes place, usually in the upper portion of a boiler's combustion chamber, to reduce the level of CO in the boiler exhaust gases. GP will use a modern OFA system on the No. 4 Combination Boiler.

The use of an OFA system in a wood-fired boiler can reduce CO emissions up to 25 percent compared to CO emission levels in boilers without an OFA system. Levels of CO that are indicative of complete combustion in a wood-fired boiler can range from 400 to 800 parts per million by volume (ppmv), depending upon fuel quality, moisture content, and combustion control.

If a boiler is using other internal combustion modification techniques, such as LNBs, the CO concentration will tend to be higher than it would be in the absence of the LNBs. Combustion modification techniques, in general, have the goal of accomplishing complete combustion and reducing both CO and NO_x emissions. Depending on the configuration of these systems and the distribution of air, in some cases NO_x may be reduced at the expense of increasing CO and vice-versa. It is a recognized fact that installing controls to reduce emissions of one of these pollutants will raise emissions of the other pollutant. Generally speaking, however, facilities will attempt to achieve a balance between the emission levels of these two pollutants.

Post-Combustion Control – Oxidation Catalyst

The primary post-combustion technique used to reduce CO emissions is the use of an oxidation catalyst system. These conventional systems can provide between 70- to 95-percent reduction of CO emissions by passing the boiler flue gas exhaust through a catalyst bed that converts the exhaust gases to carbon dioxide and water vapor. These systems work best if the flue gas exhaust temperature is within the range of 600 to 1,100°F, with an optimum temperature of about 800°F. If the exhaust gas stream temperature of the combustion device in question is lower than the optimum temperature range, then additional heat is needed in order to raise the temperature to the desired level. This may add significant operating costs to the control system since supplemental fuel must be burned in order to supply the additional heat.

The catalyst material for a CO oxidation catalyst system can be purchased from a number of catalyst manufacturers in the United States. However, the integration of the catalyst into a working module for installation on boiler exhaust gases may need to be handled by a separate company. These conventional catalysts work best when clean fuel(s) are being burned, such as natural gas, propane, or No. 1 or No. 2 fuel oil. Oxidation catalysts are sensitive to contamination from particulate matter build-up, which can cause the catalyst to become plugged or coated, thereby losing its effectiveness. If the catalyst becomes plugged with particulate matter, the catalyst beds must be removed from service and cleaned. This can result in significant periods of downtime for the boiler. If other fuels are burned, such as wood, particulate matter, and toxic metals may interfere with the catalysts' ability to react with the exhaust gases and convert the gases to carbon dioxide and water vapor. Toxic metals can actually poison the catalyst, rendering it useless (similar to what was discussed earlier under SCR systems for NO_x control).

For these reasons, a CO oxidation catalyst system would only have a chance of working in a wood-fired boiler application if it were placed downstream of the particulate matter control device, such as an ESP or baghouse. Soot blowers may still be necessary to remove the remaining particulate matter exiting the ESP to eliminate the possibility of toxic metals build-up that could poison the catalyst.

The same catalysts used to reduce CO emissions also work to reduce emissions of VOC compounds. The catalyst works by helping to oxidize the unburned hydrocarbons (or VOCs) from the combustion process into carbon dioxide and water vapor. The catalysts used to reduce VOCs also work best at a temperature of approximately 800°F.

5.4.4 Environmental Impacts

As shown in Attachment C of the No. 4 Recovery Boiler application, the maximum predicted CO impacts for the proposed project are less than the EPA Class I and II significant impact levels, respectively. Additional CO controls would result in an insignificant reduction of ambient impacts that are already less than the EPA significance levels for both Class I and II areas.

5.4.5 Energy Impacts

Although thermal incinerators are theoretically feasible for the Boiler, it is estimated that the total incinerator natural gas usage would be approximately 14,000 standard cubic feet per hour (scf/hr), equal to 120 million standard cubic feet per year (MMscf/yr) because of the high flue gas volume and low concentration of CO. The combustion of natural gas would result in increased NO_x emissions, as well as have a significant economic impact (approximately $840,000 per year). For this reason, incineration is considered to be infeasible for the Boiler.

5.4.6 Economic Analysis

As stated above, for an oxidation catalyst system to have any chance of working properly on a wood-fired boiler, the catalyst must be placed downstream of the particulate matter control system so the catalyst will not be deactivated or poisoned. Additionally, a duct burner would need to be added to raise the temperature of the flue gas exhaust from 340°F to approximately 800°F so the catalyst will work effectively. Third, a soot blower would be needed to keep the catalyst free of any toxic metal build-up.

Raising the temperature of the flue gas would require the Mill to burn approximately 235 MMscf/year) of natural gas per year (34.3 MMBtu/hr) at a cost of almost $2.4 million per year (based on $10/MMBtu). Additionally, this would add approximately 15 tons of CO that would need to be treated, assuming the use of a 40-MMBtu/hr (low-NO_x) duct burner.

Using a duct burner creates a huge financial penalty that in itself adds an operating cost of about $5,700 per ton of CO reduced (assuming a 95-percent reduction in CO emissions, or 386.3 TPY). It is not a wise use of a valuable energy resource when the temperature of the flue gas exhausted from the ESP must be substantially raised when the Boiler is designed to recoup heat with an economizer. An expenditure of $2.4 million per year for the duct burner will negate a significant portion of the cost savings realized by generating cheaper electricity with the Boiler and would seriously compromise the financial viability of this project. In fact, the Mill could certainly not justify the modifications to the Boiler if its operating costs just for burning natural gas were $2.4 million per year.

For these reasons, consideration of an oxidation catalyst system for the Boiler is considered economically infeasible and a waste of a valuable energy resource (natural gas). Therefore, an oxidation catalyst system for the Boiler will not be addressed any further as part of this BACT analysis.

5.4.7 BACT Selection

The only feasible control technologies for CO control in the No. 4 Combination Boiler are good combustion practices and design of the OFA system. The No. 4 Combination Boiler will employ this control technique.

CO emissions are proposed to be controlled through proper furnace design and good combustion practices, including control of combustion air and temperature and distribution of fuel on the grate, as well as control over furnace loads and transient conditions. The proposed BACT emission limit for the No. 4 Combination Boiler is 0.50 lb/MMBtu when firing bark/wood, equivalent to 1,012 TPY, and 5 lbs/1,000 gallons for fuel oil firing, equivalent to 12.5 TPY. The bark/wood limit is based on estimates from the OFA system vendors. The proposed limit for fuel oil is based on AP-42.

5.5 Volatile Organic Compounds

5.5.1 Previous BACT Determinations

As part of the BACT analysis, a review was performed of previous VOC BACT determinations for industrial boilers listed in the RBLC on EPA's web page. A summary of the BACT determinations for biomass-fired industrial boilers from this review is presented in Table 5-14. The VOC emission limits for biomass-fired industrial boilers identified in the RBLC search range from 0.05 to 0.5 lb/MMBtu and from 34.5 to 131.5 lbs/hr, with one determination at 1.7 TPY. This rather large range of emissions is due to differences in boiler design and operation, as well as differences in fuel. From the review of previous determinations, it is evident that VOC BACT determinations for biomass-fired industrial boilers have all been based on good combustion practices and boiler design.

A review of the entries in Table 5-14 indicates the following control technologies in use to remove VOC emissions:

- Good combustion practices,
- No controls,
- Good design and operation,
- Proper design and operation and combustion control,
- Catalytic oxidation,
- Efficient combustion, and
- High pressure OFA.

The entry listed above for an oxidation catalyst is for a Biomass Energy plant in South Point, Ohio. According to the Ohio EPA, the facility has not yet started construction. The control system planned is for the combined flue gas from seven wood-fired boilers, each rated at 175 MMBtu/hr heat input. After discussing this project with the environmental consulting firm that prepared the air quality permit application for the facility, it was determined that in 1999, when the original air quality permit application for this project was submitted, the air quality control region was designated as non-attainment for CO. Biomass Energy had to propose the installation of an oxidation catalyst system in order to meet requirements for the "lowest achievable emission rate" (LAER) of CO emissions, and not for VOCs.

Today, the air quality region where the Biomass Energy Plant is located is in attainment for CO. However, the Plant has decided to voluntarily install the oxidation catalyst even though it would no longer be required (LAER is no longer applicable and CO was not triggered as a PSD pollutant for this particular project). Since the Plant is not yet operating, it cannot be determined how well the oxidation catalyst will work in reducing CO or VOC emissions from the seven wood-fired boilers.

5.5.2 Control Technology Feasibility

The technically feasible VOC controls for the No. 4 Combination Boiler are shown in Table 5-15. There are two main approaches that can be used to reduce VOC emissions from boilers. The first is good combustion practices and the second involves the addition of post-combustion controls. Both of these approaches are discussed in subsequent sections.

5.5.3 Potential Control Method Descriptions

Good Combustion Practices

Examples of "good combustion practices" for a wood-fired boiler include operator practices, maintenance practices, maintaining proper stoichiometric fuel/air ratios, monitoring of fuel quality and consistency, temperature, and combustion air distribution. Additionally, a start-up, shutdown, and malfunction plan should be developed and followed to ensure that emissions are minimized to the extent practicable during these periods of operation. All of these factors can affect the pollutant emission rate generated by the Boiler. By following these "good combustion practices", VOC emissions will be minimized.

There is no specific percent reduction that can be given for using good combustion practices. However, without these practices, VOC emissions from a wood-fired boiler will increase significantly, by a factor of 100 percent or more, as compared to a boiler that uses good combustion practices. Good combustion practices are technically feasible to reduce VOC emissions from a wood-fired boiler. Therefore, it is in the Mill's interest to use good combustion practices so that boiler efficiency is not compromised.

Post-Combustion Control - Oxidation Catalyst

The primary post-combustion technique used to reduce VOC emissions is an oxidation catalyst system. These conventional systems can provide between 70- to 95-percent reduction of VOC emissions by passing the boiler flue gas exhaust through a catalyst bed that converts the exhaust gases to carbon dioxide and water vapor. The operation and limitations of this type of control system is discussed in great detail above for CO. As such, that information is not repeated in this section.

None of the wood-fired boilers at GP's pulp and paper mills or wood products plants have specific pollution control systems in place to reduce VOC emissions. However, all of the Mills' boilers are operated in an efficient manner to reduce VOC emissions. Boilers operating at the proper combustion chamber temperature and the correct combustion fuel/air ratio minimize VOC emissions.

5.5.4 Economic Evaluation

The economic analysis is based on cost data supplied by the equipment suppliers, GP experience at other locations, and the use of cost estimating spreadsheets contained in Chapter 2 of EPA's Office of Air Quality Planning & Standards (OAQPS) Control Cost Manual, 5th Edition, February 1996 (Chapter 2 - Cost Estimating Methodology).

Oxidation Catalyst

The potential VOC emission rate from the Boiler is only 34.4 TPY. Even though an oxidation catalyst will control both CO and VOC emissions, the cost per ton of both of these pollutants reduced is $2,400 per ton based on the cost of natural gas in the duct burner alone (assuming 95-percent reduction for both pollutants which equates to 960 TPY reduction in CO emissions and 32 TPY reduction in VOC emissions). As discussed above for CO, an expenditure of $2.4 million per year for the duct burner would negate a significant portion of the cost savings realized by burning less fuel oil and more bark/wood with the No. 4 Combination Boiler upgrade, and would render the project economically infeasible.

For the reasons listed above, consideration of an oxidation catalyst system to control VOC emissions from the No. 4 Combination Boiler is considered economically infeasible and consumption of a valuable energy resource (natural gas). For these reasons, an oxidation catalyst system for the No. 4 Combination Boiler is not considered further.

Good Combustion Practices

The costs associated with maintaining good operating practices for a wood-fired boiler are the direct operating costs for operating and supervisory labor to make sure the Boiler is functioning as it should at all times.

5.5.5 BACT Selection

The only technology remaining in the BACT analysis for the reduction of VOC emissions that has not been discarded due to technical or economic infeasibility is good combustion practices. GP will operate the No. 4 Combination Boiler in a manner that minimizes pollutant emissions by using good combustion practices. The good combustion practices will be documented in a standard operating procedure that will be used as a training guide for the Boiler operators.

The proposed VOC emission limit is 9.6 lbs/hr.

5.6 Sulfuric Acid Mist

5.6.1 Previous BACT Determinations

Presented in Table 5-16 are previous BACT determinations for SAM emissions from wood-fired industrial boilers. Combustion control is the only control method employed in these BACT determinations. An emission limit of 0.015 lb/MMBtu without any add-on control constitutes BACT for a previous determination. Although there were no controls identified as part of the RBLC search for controlling emissions of SAM from wood-fired boilers, GP is aware that ESPs and wet scrubbers can be very effective in the removal of SAM.

5.6.2 Control Technology Feasibility

The technically feasible SAM controls for the No. 4 Combination Boiler are ESPs, good combustion practices/control, and wet scrubbers as presented in Table 5-17. GP believes that all three controls are technically feasible.

5.6.3 Potential Control Method Descriptions

GP has identified two add-on control technologies and one pollution prevention technique. The technical feasibility of each of these control approaches is discussed in the following subsections.

Dry and Wet ESPs

ESPs use electrical energy to charge and collect particles with very high removal efficiency. The classification of ESPs may be as wet or dry systems and single-stage or two-stage systems. Dry systems are the predominant type used in industrial applications. Wet systems are gaining in popularity today since they eliminate the possibility of fires, which can sometimes occur in dry systems.

The principal components of a dry ESP include the housing, discharge and collection electrodes, power source, cleaning mechanism, and solids handling systems. The housing is gas-tight, weatherproof, and grounded for safety. Dust particles entering the housing are charged by ions from the discharge electrodes. Dust is collected on the collection electrodes. The collection electrodes are also referred to as plates. The system voltage and the distance between the discharge and collection electrodes govern the electric field strength and the amount of charge on the particles. Dry ESPs are most effective at collecting coarse, larger particles [above the 1.0-micrometer (μm) size]. Particles smaller than this are difficult to remove because they can inhibit the generation of the charging corona in the inlet field, thereby reducing collection efficiency. Rappers serve as the cleaning mechanisms for dry ESPs. Dust hoppers collect the precipitated particles from a dry ESP. Dust is removed continuously or periodically from the hopper and stored in a container until final disposition.

Wet ESPs operate a wet wall on the back of an ESP, with either continuous or intermittent water flow. The water flow is collected into a sump. The advantage to a wet ESP is that it has no back coronas and there is a reduced risk of fire.

PM collection efficiencies for both types of systems (dry or wet) are usually at or above 95 to 99 percent. A wet ESP may have somewhat better SAM removal due to the additional scrubing action afforded by the water flow. Both dry and wet ESPs are technically feasible for the No. 4 Combination Boiler. Removal efficiencies for SAM would be in the same range as what is seen for PM, i.e., as high as 98 to 99 percent. The No. 4 Combination Boiler will utilize a dry ESP.

Wet Scrubber

Wet scrubbers are collection devices that trap wet particles to remove them from a gas stream. They utilize inertial impaction and/or Brownian diffusion as the particle collection mechanism. Wet scrubbers generally use water as the cleaning liquid. Water usage and wastewater disposal requirements are important factors in the evaluation of a scrubber alternative. Types of scrubbers include spray scrubbers, cyclone scrubbers, packed-bed scrubbers, plate scrubbers, and venturi scrubbers.

The most common type of scrubber used in this application is the venturi scrubber because of its simplicity (no moving parts) and high collection efficiency. In this type of scrubber, a gas stream is passed through a venturi section, with a low-pressure liquid (usually water) added to the throat. The liquid is atomized by the turbulence in the throat and begins to collect particles impacting the liquid as a result of differing velocities for the gas stream and atomized droplets. A separator is used to remove the particles or liquid from the gas stream.

The most important design consideration is the pressure drop across the venturi. Generally, the higher the pressure drop, the higher the collection efficiency. Venturi scrubbers with a pressure drop greater than 15 in. H_2O usually have collection efficiencies near 85 percent. Venturi scrubbers with higher pressure drops can result in collection efficiencies up to 98 percent. Wet scrubbers are technically feasible for the No. 4 Combination Boiler.

Some SAM removal would be expected from the use of a venturi scrubber. Although the exact removal efficiency for SAM is not known, this technology can be effective in the removal of sulfur compounds in general.

5.6.4 Good Combustion Practices

The formation of SAM in a bark/wood and oil-fired boiler is minimized by ensuring efficient combustion of the fuel in the burner. Efficient combustion is a function of several parameters, including the quantity of O_2 supplied in the burner to support combustion of the fuel and the temperature and residence time inside the furnace.

Another factor that must be considered for efficient combustion of fuel oil is atomization in the burner. To burn fuel oil efficiently, the burner must be atomized correctly, with the oil sprayed into a the Boiler in a controlled manner. Droplet size is critical in determining the mixing rate of fuel oil and air. If the droplet size is too coarse, the larger drops take longer to burn, which affects combustion efficiency.

Good combustion control practices manage the process to maintain a consistent level of conversion of reduced sulfur compounds to SO_2. GP believes that ensuring efficient combustion of the fuel is a technically feasible manner in which to control emissions of SAM.

5.6.5 BACT Selection

The only economically feasible control technologies for SAM control for the No. 4 Combination Boiler are good combustion practices/controls and use of the existing dry ESP. The No. 4 Combination Boiler will employ these control techniques. Since the No. 4 Combination Boiler already utilizes a highly efficient PM control device (a dry ESP) which also removes some SAM emisisons, it would not be cost effective to add an additional wet scrubber, or to replace the existing dry ESP with a wet ESP. Any type of replacement or add-on PM/SAM control technology would cost several million dollars in capital cost. Due to the already low SAM emission rate, the cost effectiveness would be very high for these options.

Maximum SAM emissions from the No. Combination Boiler are proposed at 47.3 lbs/hr, which reflects maximum hourly fuel oil burning, and 45 TPY, which reflects maximum annual fuel oil burning with the remainder of the time firing bark/wood.

TABLE 5-1
BACT DETERMINATIONS FOR PM/PM10 FOR BIOMASS-FIRED INDUSTRIAL BOILERS

Company	State	RBLC ID	Permit Number	Permit Date	Primary Fuel	Throughput		Emission Limits		Control Equipment Description	Removal Efficiency %
								LAER/BACT Clearinghouse	Converted to lb/MMBtu[a]		
City of Virginia, Laurention Energy, Virginia Department of Public Utilities	MN	MN-0058	13700028-005	6/30/2005	Wood	230 MMBtu/hr	PM/PM_{10} =	0.025 lb/MMBtu	0.025	ESP	98
Laurention Energy Authority, Hibbing Public Utilities	MN	MN-0059	13700028-003	6/30/2005	Wood	230 MMBtu/hr	PM/PM_{10} =	0.025 lb/MMBtu	0.025	ESP	90
Public Service of New Hampshire - Schiller Station	NH	NH-0013	TP-B-0501	10/25/2004	Wood	720 MMBtu/hr	PM_{10} =	0.025 lb/MMBtu	0.025	Fabric Filter[b]	99
Temple Inland Inc. - Rome Linerboard Mill	GA	GA-0114	2631-115-0021-V-01-4	10/13/2004	Bark	856 MMBtu/hr	PM_{10} =	0.025 lb/MMBtu	0.025	ESP	--
US Sugar Corp. - Clewiston Blr No. 8	FL	FL-0257	PSD-FL-333	11/18/2003	Bagasse	936 MMBtu/hr	PM =	0.026 lb/MMBtu	0.026	Wet cyclone and ESP	99
Georgia-Pacific Corp. - Monticello Mill	MS	MS-0075	1500-00007	7/9/2003	Scrap wood	917.4 MMBtu/hr	PM_{10} =	91.7 lb/hr	0.10	Multiclone and ESP	--
Interstate Paper, LLC	GA	GA-0097	2631-179-0001-V-01-1	12/30/2002	Multifuel (Wood, Residual Fuel Oil, Natural Gas, TDF)	300 MMBtu/hr	PM =	0.03 lb/MMBtu	0.03	ESP	--
Sierra Pacific Industries - Aberdeen Division	WA	WA-0298	PSD-02-02	10/17/2002	Waste Wood	310 MMBtu/hr	PM =	0.02 lb/MMBtu	0.02	ESP	--
Meadwestvaco Kentucky Inc.	KY	KY-0085	VF-01-002	2/27/2002	Bark	631 MMBtu/hr	PM =	0.10 lb/MMBtu	0.10	ESP	--
Martinsville Thermal, LLC - Thermal Ventures	VA	VA-0268	30529	2/15/2002	Wood/Coal	120 MMBtu/hr	PM =	0.150 lb/MMBtu	0.15	Good Combustion Practices and Clean Burning Fuels	--
Martinsville Thermal, LLC - Thermal Ventures	VA	VA-0268	30529	2/15/2002	Wood/Coal	120 MMBtu/hr	PM_{10} =	0.140 lb/MMBtu	0.14	Good Combustion Practices and Clean Burning Fuels	--
Georgia-Pacific Corp. - Port Hudson Operations	LA	LA-0174	PSD-LA-581 (M-2)	1/25/2002	Woodwaste/Natural Gas	459.5 MMBtu/hr	PM/PM_{10} =	32.42 lb/hr	0.071	Wet Scrubbers	--
S.D. Warren Co. - Skowhegan, ME	ME	ME-0021	A-19-17-K-A	11/27/2001	Woodwaste	1300 MMBtu/hr	PM =	171 TPY	0.03	Mechanical Dust Collector and ESP	99
District Energy St. Paul Inc.	MN	MN-0046	12300063-001	11/15/2001	Wood	550 MMBtu/hr	PM =	0.03 lb/MMBtu	0.03	Cyclone and ESP	99
Grayling Generating Station	MI	MI-0285	882-89E	9/18/2001	Wood/Tires	500 MMBtu/hr	PM =	0.03 lb/MMBtu	0.03	Multiclones and ESP	--
International Paper - Mansfield Mill	LA	LA-0122	PSD-LA-93 (M-6)	8/14/2001	Woodwaste, Coal, Natural Gas, Oil, Recycled Plant Fiber	760 MMBtu/hr	PM_{10} =	76 lb/hr	0.10	Single State Dust Collector and ESP	99.5
Tri-Gen BioPower	GA	GA-0117	2631-039-0025-P-01-1	5/24/2001	Woodwaste/Papermill Sludge	302.2 MMBtu/hr	PM_{10} =	8 lb/hr	0.026	ESP and Wet Scrubber	--
International Paper Company - Riegelwood Mill	NC	NC-0092	03138R16	5/10/2001	Bark/Wood, Sludge, Fossil Fuels	600 MMBtu/hr	PM =	0.25 lb/MMBtu	0.25	Multicyclone and a Variable Throat Venturi-Type Scrubber	--
U.S. Sugar Corporation - Boiler No. 4	FL	FL-0248	PSD-FL-272	11/19/1999	Bagasse/No. 6 Fuel Oil	633 MMBtu/hr	PM =	0.15 lb/MMBtu	0.15	Good Combustion Practices and Wet Impingement Scrubber	93
Weherhaeuser Co. - Valliant - No. 2 Power Boiler	OK	OK-0084	96-043-C PSD M-3	6/8/1999	Mixed Fuels	--	PM =	0.03 lb/MMBtu	0.03	Proper Design and Operation and Combustion Control	--
Wheelabrator Sherman Energy Company	ME	ME-0026	1-67-71-K-A/R	4/9/1999	Woodwaste	315 MMBtu/hr	PM =	11.4 lb/hr	0.036	ESP and Cyclone	--
Gulf States Paper Corp.	AL	AL-0122	406-S003	10/14/1998	Wood	98 MMBtu/hr	PM =	0.10 lb/MMBtu	0.10	Multicyclone and ESP	99
Sierra Pacific Industries--Quincy	CA	CA-0930	SAC-97-01	5/13/1998	Wood	245.3 MMBtu/hr	PM_{10} =	0.035 lb/MMBtu	0.035	Multicyclones and ESP	--
Champion International	AL	AL-0112	707-0001-X033	12/9/1997	Woodwaste, Effluent Solids, Non-Recyclable Paper, TDF, Natural Gas, NCGs	710 MMBtu/hr	PM =	0.03 lb/MMBtu	0.03	ESP	99
Corn Products International	NC	NC-0066	00732-TV-4	7/15/1997	Wood/Natural Gas	324.5 MMBtu/hr	PM_{10} =	0.03 lb/MMBtu	0.03	Multicone followed by an ESP	97.5
Mead Containerboard	AL	AL-0099	705-0014-X014 and - X015	1/15/1997	Wood, NCGs, WTP Sludges	620 MMBtu/hr	PM =	0.03 lb/MMBtu	0.03	Multicyclone and ESP	99.2
Weherhaeuser Co. - Valliant - Bark Boiler	OK	OK-0038	96-043-C PSD	11/5/1996	Wood, Gas, Oil, WTP Sludges	--	PM_{10} =	0.10 lb/MMBtu	0.10	Wet Scrubber	90
Weherhaeuser Co.	MS	MS-0029	1680-00044	9/10/1996	Bark/Wood, Natural Gas, Oil, Coal, NCGs, Sludge	1600 MMBtu/hr	PM/PM_{10} =	0.045 lb/MMBtu	0.045	Electroscrubber with Multiclones	99.5
Apple Grove Pulp and Paper Company Inc.	WV	WV-0016	R14-11	6/17/1996	Woodwaste/Natural Gas	772.6 MMBtu/hr	PM =	7.44 lb/hr	0.01	Multiclone and Fabric Filtration	99.6
Willamette Industries - Marlboro Mill	SC	SC-0045	1680-0043	4/17/1996	Woodwaste/Bark/Natural Gas	470 MMBtu/hr	PM =	0.05 lb/MMBtu	0.05	ESP	99.5
Potlatch Corporation	AR	AR-0073	117-AR-2	9/8/1995	Woodwaste	159.29 MMBtu/hr	PM =	15.9 lb/hr	0.10	ESP with Multiclone	--
Weherhaeuser Co.	MS	MS-0026	0300-00032	5/9/1995	Wood/Bark/Waste	90 MMBtu/hr	PM/PM_{10} =	0.10 lb/MMBtu	0.10	None	--
Georgia-Pacific Corporation - Gloster Facility	MS	MS-0023	0080-00013	4/11/1995	Wood/Woodwaste	244 MMBtu/hr	PM/PM_{10} =	0.10 lb/MMBtu	0.10	None	--
U.S. Sugar Corporation - Clewiston Blr No. 7	FL	FL-0094	PSD-F-208	1/31/1995	Bagasse	738 MMBtu/hr	PM/PM_{10} =	22 lb/hr	0.03	ESP	--

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, January 2006.

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

[b] Public Services of New Hampshire took the PM limit of 0.025 lb/MMBtu to earn renewable energy credits not for BACT. They only triggered BACT for CO. The have a vendor guarantee for the limit with the fabric filter. The boiler has not finished constuction, and startup is anticipated for August or September 2006.

TABLE 5-2
BACT DETERMINATIONS FOR PM/PM10 FOR FUEL OIL-FIRED INDUSTRIAL BOILERS

Company	State	RBLC ID	Permit Number	Permit Date	Primary Fuel	Throughput		Emission Limits		Control Equipment Description	Removal Efficiency %
								LAER/BACT Clearinghouse	Converted to lb/MMBtu[a]		
Miller Brewing Company - Trenton	OH	OH-0241	14-05515	5/27/2004	No. 6 Fuel Oil	238 MMBtu/hr	PM_{10} =	0.125 lb/MMBtu	0.125	Baghouse	--
Virginia Commonwealth University - VCU East Plant	VA	VA-0270	50126	3/31/2003	No. 6 Fuel Oil	150 MMBtu/hr	PM =	0.063 lb/MMBtu	0.063	Good Combustion Practices	--
							PM_{10} =	0.05 lb/MMBtu	0.05	Good Combustion Practices	--
SPI Polyols, Inc.	DE	DE-0017	AQM-003/00426	10/26/2001	No. 6 Fuel Oil	115 MMBtu/hr	PM =	0.30 lb/MMBtu	0.30	Proper Quality Fuels	--
International Paper Company - Riegelwood Mill	NC	NC-0092	03138R16	5/10/2001	No. 6 Fuel Oil	249 MMBtu/hr	PM =	0.0562 lb/MMBtu	0.0562	Multicyclone and a Variable Throat Venturi-Type Scrubber	--
Rayonier, Inc.	FL	FL-0182	PSD-FL-256	12/17/1998	No. 6 Fuel Oil	212 MMBtu/hr	PM/PM_{10} =	21 TPY	0.023	None	--

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, January 2006.

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

TABLE 5-3
PM/PM$_{10}$ CONTROL TECHNOLOGY FEASIBILITY ANALYSIS FOR THE NO. 4 COMBINATION BOILER

PM/PM$_{10}$ Abatement Method	Technique Now Available	Estimated Efficiency	Technically Feasible? (Y/N)	Demonstrated? (Y/N)	Rank Based on Control Efficiency	Employed by No. 4 Combination Boiler? (Y/N)
1. Fuel Techniques	Fuel Substitution	NA	Y	Y	7	N
2. Pretreatment	Settling Chambers	< 10%	Y	Y	6	N
	Elutriators	< 10%	Y	Y	6	N
	Momentum Separators	10 - 20%	Y	Y	5	N
	Mechanically-Aided Separators	20 - 30%	Y	Y	4	N
	Cyclones	60 - 90%	Y	Y	3	Y
3. Electrostatic Precipitators (ESP)	Dry ESP	>99%	Y	Y	1	Y
	Wet ESP	>99%	Y	Y	1	N
	Wire-Plate ESP	>99%	Y	Y	1	N
	Wire-Pipe ESP	>99%	Y	Y	1	N
4. Fabric Filters	Shaker-Cleaned	>99%	N	NA	NA	N
	Reverse-Air	>99%	N	NA	NA	N
	Pulse-Jet	>99%	N	NA	NA	N
5. Wet Scrubbers	Spray Chambers	50 - 95 %	Y	Y	2	N
	Packed-Bed	50 - 95 %	Y	Y	2	N
	Impingement Plate	50 - 95 %	Y	Y	2	N
	Mechanically-Aided	50 - 95 %	N	NA	NA	N
	Venturi	50 - 95 %	Y	Y	2	N
	Orifice	50 - 95 %	Y	Y	2	N
	Condensation	50 - 95 %	Y	Y	2	N
6. Mist Eliminators	Fiber Bed	<5 %	N	N	8	N
	Mesh Pad	<5 %	Y	Y	8	N
	Chevron	<5 %	Y	Y	8	N

Note: NA = Not Applicable

TABLE 5-4
SUMMARY OF HISTORICAL PM STACK TEST DATA FOR THE NO. 4 COMBINATION BOILER, GP PALATKA

Test Date	Heat Input Rate (MMBtu/hr)	Total PM Emissions lb/hr	Total PM Emissions lb/MMBtu	Individual Heat Input Rates (MMBtu/hr) Due to Oil	Individual Heat Input Rates (MMBtu/hr) Due to Bark/Wood	PM Emissions (lb/hr) -- Contributions by Individual Fuels Due to Oil/Wood Only [a]	PM Emissions (lb/hr) -- Contributions by Individual Fuels Due to Bark/Wood Only [b]	PM Emissions (lb/MMBtu) Due to Bark/Wood Only
Wood/Bark and Fuel Oil in Combination								
8/18/2005	476	19.3	0.04	148	328	5.61	13.69	0.042
1/8/2004	496	39.10	0.090	107	389	4.05	35.05	0.090
1/8/2003	457	26.42	0.060	107	350	4.06	22.36	0.064
6/18/02-6/21/02	455	19.73	0.047	155	300	5.88	13.85	0.046
7/18/2001	442	15.77	0.040	151	291	5.74	10.03	0.034
4/18/2000	438	43.77	0.101	103	335	3.91	39.86	0.119
5/19/1999	473	14.20	0.030	126	347	4.80	9.40	0.027
5/6/1998	458	16.00	0.040	144	314	5.48	10.52	0.034
2/20/1997	453	40.00	0.090	119	334	4.51	35.49	0.106
4/2/1996	502	26.00	0.052	321	181	12.21	13.79	0.076
7/24/95-7/25/95	470	38.34	0.080	242	228	9.20	29.14	0.128
		No. of tests =	**11**				**No. of tests =**	**11**
		Average =	**0.061**				**Average =**	**0.070**
		Standard Deviation =	**0.025**				**Standard Deviation =**	**0.037**
		95% Confidence Interval Upper Limit =	**0.116**				**95% Confidence Interval Upper Limit =**	**0.151**
		99% Confidence Interval Upper Limt =	**0.140**				**99% Confidence Interval Upper Limt =**	**0.185**
Fuel Oil Only								
8/22/2005	381	17.50	0.050					
1/8/2004	403	12.60	0.030					
1/8/2003	420	13.87	0.033					
		No. of Tests =	**3**					
		Average =	**0.038**					
		Standard Deviation =	**0.011**					
		95% Confidence Interval Upper Limit =	**0.084**					
		99% Confidence Interval Upper Limit =	**0.145**					

[a] Assumed at 0.038 lb/MMBtu from average of fuel oil only stack tests.

[b] Calculated by difference between total PM emissions and PM emissions due to fuel oil burning.

TABLE 5-5
BACT DETERMINATIONS FOR NOx FOR BIOMASS-FIRED INDUSTRIAL BOILERS

Company	State	RBLC ID	Permit Number	Permit Date	Primary Fuel	Throughput	Emission Limits		Control Equipment Description	Removal Efficiency %
							As Provided in LAER/BACT Clearinghouse	Converted to lb/MMBtu[a]		
City of Virginia, Laurention Energy, Virginia Department of Public Utilities	MN	MN-0058	13700028-005	6/30/2005	Wood	230 MMBtu/hr	0.15 lb/MMBtu	0.15	SNCR	50
Laurention Energy Authority, Hibbing Public Utilities	MN	MN-0059	13700028-003	6/30/2005	Wood	230 MMBtu/hr	0.15 lb/MMBtu	0.15	SNCR	50
Public Service of New Hampshire - Schiller Station	NH	NH-0013	TP-B-0501	10/25/2004	Wood	720 MMBtu/hr	0.075 lb/MMBtu	0.075	SNCR	65
US Sugar Corp. - Clewiston Blr No. 8	FL	FL-0257	PSD-FL-333	11/18/2003	Bagasse	936 MMBtu/hr	0.14 lb/MMBtu	0.14	SNCR with Good Combustion and Operating Practices	50
Georgia-Pacific Corp. - Monticello Mill	MS	MS-0075	1500-00007	7/9/2003	Scrap wood	917.4 MMBtu/hr	284.4 lb/hr	0.31	Low NOx Burners, Stroker Controls, Overfire Ai	--
Interstate Paper, LLC	GA	GA-0097	2631-179-0001-V-01-1	12/30/2002	Multifuel (Wood, Residual Fuel Oil, Natural Gas, TDF)	300 MMBtu/hr	0.25 lb/MMBtu	0.25	Fluidized Bed Boiler	--
Sierra Pacific Industries - Aberdeen Division	WA	WA-0298	PSD-02-02	10/17/2002	Waste Wood	310 MMBtu/hr	0.15 lb/MMBtu	0.15	SNCR, Boiler Design	--
Meadwestvaco Kentucky Inc.	KY	KY-0085	VF-01-002	2/27/2002	Bark	631 MMBtu/hr	0.4 lb/MMBtu	0.4	None	--
Martinsville Thermal, LLC - Thermal Ventures	VA	VA-0268	30529	2/15/2002	Wood/Coal	120 MMBtu/hr	0.4 lb/MMBtu	0.4	Good Combustion Practices	--
Martinsville Thermal, LLC - Thermal Ventures	VA	VA-0268	30529	2/15/2002	Wood/Coal	120 MMBtu/hr	0.4 lb/MMBtu	0.4	Good Combustion Practices	--
Georgia-Pacific Corp. - Port Hudson Operations	LA	LA-0174	PSD-LA-581 (M-2)	1/25/2002	Woodwaste/Natural Gas	459.5 MMBtu/hr	128.7 lb/hr	0.28	Low NOx Burners	--
S.D. Warren Co. - Skowhegan, ME	ME	ME-0021	A-19-17-K-A	11/27/2001	Woodwaste	1300 MMBtu/hr	0.2 lb/MMBtu	0.2	SNCR	--
District Energy St. Paul Inc.	MN	MN-0046	12300063-001	11/15/2001	Wood	550 MMBtu/hr	0.15 lb/MMBtu	0.15	SNCR	--
Grayling Generating Station	MI	MI-0285	882-89E	9/18/2001	Wood/Tires	500 MMBtu/hr	0.156 lb/MMBtu	0.156	SNCR, Urea Injection	--
International Paper Company - Riegelwood Mill	NC	NC-0092	03138R16	5/10/2001	Bark/Wood, Sludge, Fossil Fuels	600 MMBtu/hr	0.35 lb/MMBtu	0.35	Good Combustion Practices	--
U.S. Sugar Corporation - Boiler No. 4	FL	FL-0248	PSD-FL-272	11/19/1999	Bagasse/No. 6 Fuel Oil	633 MMBtu/hr	0.2 lb/MMBtu	0.2	Good Combustion Practices	--
Weherhaeuser Co. - Valliant - No. 2 Power Boiler	OK	OK-0084	96-043-C PSD M-3	6/8/1999	Mixed Fuels	--	0.15 lb/MMBtu	0.15	Low NOx Burners with or without FGR	--
Wheelabrator Sherman Energy Company	ME	ME-0026	1-67-71-K-A/R	4/9/1999	Woodwaste	315 MMBtu/hr	0.25 lb/MMBtu	0.25	Good Combustion Practices	--
Tri-Gen BioPower	GA	GA-0116	2631-039-0025-P-01-0	11/25/1998	Woodwaste/Papermill Sludge	265.1 MMBtu/hr	0.25 lb/MMBtu	0.25	Fluidized Bed Boiler and Inherent NOx Formation Control Features	--
Gulf States Paper Corp.	AL	AL-0122	406-S003	10/14/1998	Wood	98 MMBtu/hr	0.3 lb/MMBtu	0.3	None	--
Sierra Pacific Industries--Quincy	CA	CA-0930	SAC-97-01	5/13/1998	Wood	245.3 MMBtu/hr	0.23 lb/MMBtu	0.23	SNCR	--
Gulf States Paper Corp.	AL	AL-0116	105-0001-X027	12/10/1997	Bark and Clarifier Sludge	775 MMBtu/hr	0.3 lb/MMBtu	0.3	Low NOx Natural Gas and Fuel Oil Burners	50
Champion International	AL	AL-0112	707-0001-X033	12/9/1997	Woodwaste, Effluent Solids, Non Recyclable Paper, TDF, Natural Gas, NCGs	710 MMBtu/hr	0.25 lb/MMBtu	0.25	Addition of Tertiary Air System	30
Corn Products International	NC	NC-0066	00732-TV-4	7/15/1997	Wood/Natural Gas	324.5 MMBtu/hr	0.3 lb/MMBtu	0.3	Boiler Designed with Low Excess Air and Staged Combustion	--
Mead Containerboard	AL	AL-0099	705-0014-X014 and - X015	1/15/1997	Wood, NCGs, WTP Sludges	620 MMBtu/hr	0.25 lb/MMBtu	0.25	Combustion Controls	--
Weherhaeuser Co. - Valliant - Bark Boiler	OK	OK-0038	96-043-C PSD	11/5/1996	Wood, Gas, Oil, WTP Sludges	--	0.3 lb/MMBtu	0.3	Wet Scrubber and Overfire Air Controls	--
Weherhaeuser Co.	MS	MS-0029	1680-00044	9/10/1996	Bark/Wood, Natural Gas, Oil, Coal, NCGs, Sludge	1600 MMBtu/hr	0.5 lb/MMBtu	0.5	Continued Efficient Operation with Low NOx Burners	--
Apple Grove Pulp and Paper Company Inc.	WV	WV-0016	R14-11	6/17/1996	Woodwaste/Natural Gas	772.6 MMBtu/hr	0.1 lb/MMBtu	0.1	SNCR	--
Willamette Industries - Marlboro Mill	SC	SC-0045	1680-0043	4/17/1996	Woodwaste/Bark/Natural Gas	470 MMBtu/hr	0.3 lb/MMBtu	0.3	Good Combustion Control	--
Potlatch Corporation	AR	AR-0073	117-AR-2	9/8/1995	Woodwaste	159.29 MMBtu/hr	0.25 lb/MMBtu	0.25	Boiler Design and Operation	--
Weherhaeuser Co.	MS	MS-0026	0300-00032	5/9/1995	Wood/Bark/Waste	90 MMBtu/hr	0.23 lb/MMBtu	0.23	Combustion Controls	--
Georgia-Pacific Corporation - Gloster Facility	MS	MS-0023	0080-00013	4/11/1995	Wood/Woodwaste	244 MMBtu/hr	0.3 lb/MMBtu	0.30	None	--
U.S. Sugar Corporation - Clewiston Blr No. 7	FL	FL-0094	PSD-F-208	1/31/1995	Bagasse	738 MMBtu/hr	0.25 lb/MMBtu	0.25	Low NOx Burners	--

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, January 2006.

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

TABLE 5-6
BACT DETERMINATIONS FOR NOx FOR FUEL OIL-FIRED INDUSTRIAL BOILERS

Company	State	RBLC ID	Permit Number	Permit Date	Primary Fuel	Throughput	Emission Limits LAER/BACT Clearinghouse	Emission Limits Converted to lb/MMBtu[a]	Control Equipment Description	Removal Efficiency %
Miller Brewing Company - Trenton	OH	OH-0241	14-05515	5/27/2004	No. 6 Fuel Oil	238 MMBtu/hr	0.7 lb/MMBtu	0.7	Overfire and Sidefire Air to Reduce Flame Temperature	--
Virginia Commonwealth University - VCU East Plant	VA	VA-0270	50126	3/31/2003	No. 6 Fuel Oil	150 MMBtu/hr	0.4 lb/MMBtu	0.4	Good Combustrion Practices and Low NOx Combustion	--
SPI Polyols, Inc.	DE	DE-0017	AQM-003/00426	10/26/2001	No. 6 Fuel Oil	115 MMBtu/hr	0.48 lb/MMBtu	0.48	Maintain Excess Oxygen Levels Below 5.5% at Least 75% of the Operating Time. Annual Boiler Tune-Ups Required.	--
International Paper Company - Riegelwood Mill	NC	NC-0092	03138R16	5/10/2001	No. 6 Fuel Oil	249 MMBtu/hr	0.367 lb/MMBtu	0.367	Good Combustion Practices	--
Rayonier, Inc.	FL	FL-0182	PSD-FL-256	12/17/1998	No. 6 Fuel Oil	212 MMBtu/hr	0.425 TPY	0.425	Low NOx Burners with Flue Gas Recirculation.	20-50

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, January 2006.

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

TABLE 5-7
NOx CONTROL TECHNOLOGY FEASIBILITY ANALYSIS FOR THE NO. 4 COMBINATION BOILER

NO_x Abatement Method	Technique Now Available	Estimated Efficiency	Technically Feasible? (Y/N)	Demonstrated? (Y/N)	Rank Based on Control Efficiency	Employed by No. 4 Combination Boiler? (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%	Y	N	1	N
	Selective Non-Catalytic Reduction (SNCR)	35 - 80%	N	N	NA	N
3. Reducing residence time at peak temperature	Air Staging of Combustion	50 - 65%	Y	Y	2	Y
	Fuel Staging of Combustion	50 - 65%	Y	Y	2	N
	Inject Steam	50 - 65%	Y	Y	2	N
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	N
	Combustion Optimization	15 -25%	Y	Y	3	Y
	Reduce Air Preheat	15 -25%	Y	Y	3	N
	Low NO_x Burners (LNB)	15 -25%	N	N	NA	Y

Note: NA = Not Applicable

TABLE 5-8
COST EFFECTIVENESS OF SNCR/SCR HYBRID FOR NO. 4 COMBINATION BOILER, GP PALATKA MILL

Cost Items	Cost Factors[a]	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
SNCR/SCR Hybrid Basic Process	Vendor quote[b]	1,900,000
NOxOUT Storage Tank	10,000 gallon FRP tank; included in vendor quote	--
Tank Foundation and Structural Support	8% of equipment cost	152,000
Process Monitoring	15% of equipment cost	285,000
SCR Reactor Ductwork, Bypass and Support	15% of equipment cost	285,000
Static Mixing Device	5% of equipment cost	95,000
Freight	Vendor quote[b]	12,000
Taxes	Florida sales tax, 6%	114,000
Total PEC:		2,843,000
Direct SNCR/SCR Hybrid Installation	Vendor estimates for similar boiler: 70% of basic	1,901,900
Total DCC:		4,744,900
INDIRECT CAPITAL COSTS (ICC):		
Injector Wall Sleeves and Mounting	Based on Engineering Estimate	50,000
Air and Water Piping	Based on Engineering Estimate	50,000
Electrical and Controls	Based on Engineering Estimate	50,000
Performance Testing	Based on Engineering Estimate	100,000
Engineering and Supervision	Portion performed by GP (5% of Total DCC)	237,245
Modeling	Included in vendor quote	--
Start-up and Optimization Service	Included in vendor quote (40 man-days)	--
Operation and Maintenance Manuals (5)	Included in vendor quote	--
Temperature Monitoring	Based on Engineering Estimate	45,000
General Facilities	5% of DCC	237,245
Engineering and Home Office Fees	10% of DCC	474,490
Process Contingency	5% of DCC	237,245
Total ICC:		1,481,225
PROJECT CONTINGENCY (RETROFIT):	30% of (DCC + ICC)	1,867,838
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	8,093,963
DIRECT OPERATING COSTS (DOC):		
Operating Labor		
Operator	2 hours/week, $16/hr, 52 weeks/yr	1,664
Supervisor	15% of operator cost	250
Maintenance	1.5% of TCI	121,409
NOx-OUT solution cost (50% solution)	36 gal/hr, $1.45/gal[c], 80% C.F.	365,818
Electricity	66 kW, $0.08/kW-hr, 80% C.F.	37,002
Water	525 gph; $0.00064/gal, 80% C.F.	2,355
Fuel- bark/wood (loss in efficiency)	5 MMBtu/hr, $3/MMBtu, 80% C.F.	105,120
Annual Replacement of Catalyst	$7,720/m^3; 16,000 hr life; 46 m^3 catalyst	194,428
Total DOC:		828,046
INDIRECT OPERATING COSTS (IOC):		
Overhead	30% of oper. labor & maintenance	36,997
Property Taxes	0.5% of total capital investment	40,470
Insurance	1% of total capital investment	80,940
Administration	1% of total capital investment	80,940
Total IOC:		239,346
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.09439 times TCI (20 yrs @ 7%)	763,989
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	1,831,381
BASELINE NO_x EMISSIONS (TPY) :	Max. No. 6 fuel oil with remainder bark. 80% C.F. 0.27 lb/MMBtu for fuel oil and 0.24 lb/MMBtu for bark (90% C.F. = 496.5 TPY)	441.3 [d]
MAXIMUM NO_x EMISSIONS w/ SNCR/SCR HYBRID (TPY) :	65% reduction (bark/wood); 40% reduction (oil) 80% C.F.: (349.5*0.35)+(91.8*0.6)	157.7
REDUCTION IN NO_x EMISSONS (TPY):		283.6
COST EFFECTIVENESS:	$ per ton of NO_x Removed	6,457

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect EPA Air Pollution Cost Control Manual, Sixth Edition (EPA/452/B-02-001, Jan. 2002).

[b] NOxOUT Cascade NOx Reduction System Proposal, FuelTech, Inc., March 24, 2006.

[c] NOxOUT solution cost is based on actual cost U.S. Sugar Corporation incurs for use in their SNCR system, as of January 2006.

[d] Based on annual NOx emissions of 496.5 TPY, which is based on maximum emissions from any fuel combination without NCGs/SOGs/DNCGs, see Table B-2 of Appendix B (0.27 lb/MMBtu for fuel oil and 0.24 lb/MMBtu for bark and 80% C.F). These emissions take into account the 15-percent reduction due to the LNBs.

TABLE 5-9
COST EFFECTIVENESS FOR USING ECOTUBE SYSTEM FOR NO. 4 COMBINATION BOILER, GP PALATKA MILL

Cost Items	Cost Factors[a]	Cost ($) Without Urea	Cost ($) With Urea
DIRECT CAPITAL COSTS (DCC):			
Purchased Equipment Cost (PEC)			
NOx Reduction System Basic Process	Vendor quote[b]	2,150,000	2,150,000
Urea Storage System (Including Tank)	Quoted by vendor in email dated Dec. 22, 2005	--	800,000
Upgrading Steel Lining for Stack	Based on Engineering Estimate	--	50,000
Process Monitoring	15% of equipment cost	322,500	442,500
Foundation and Structure Support	Included in vendor quote (assume no foundations necessary)	--	--
Freight	Included in vendor quote	--	--
Taxes	Florida sales tax, 6%	129,000	177,000
Total PEC:		2,601,500	3,619,500
Direct Installation	Included in vendor quote	0	0
Total DCC:		2,601,500	3,619,500
INDIRECT CAPITAL COSTS (ICC):			
Indirect Installation Costs			
Vendor Engineering Study	Quoted by vendor in email dated Dec. 22, 2005	27,400	27,400
Travel-Related Expenses	Included in vendor quote	--	--
Air and Water Piping	Based on Engineering Estimate	50,000	50,000
Structural Steel Support/Platforms	Included in vendor quote	--	--
Electrical and Controls	Included in vendor quote	--	--
Temperature Monitoring	Based on Engineering Estimate	45,000	45,000
Start-up and Performance Testing	Based on Engineering Estimate (1 man @ 2 weeks)	100,000	100,000
Training Program	Included in vendor quote	--	--
General Facilities	5% of DCC	130,075	180,975
Engineering and Home Office Fees	Included in vendor quote	--	--
Process Contingency	5% of DCC	130,075	180,975
Total ICC:		482,550	584,350
PROJECT CONTINGENCY (RETROFIT):	30% of (DCC + ICC)	925,215	1,261,155
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	4,009,265	5,465,005
DIRECT OPERATING COSTS (DOC):			
(1) Operating Labor			
Operator	$33/man-hr x 1 man-hr/shift x 3 shifts/day x 365 day/yr	36,135	36,135
Supervisor	15% of operator cost	5,420	5,420
(2) Maintenance	3% of TCI	120,278	163,950
(3) 40% Liquid Urea	20 gal/hr, $1.20/gal[c], 80% C.F.	--	168,192
(4) Electricity	100 kW (fan), $0.08/kW-hr, 80% C.F.	63,072	56,064
Total DOC:		224,905	429,761
INDIRECT OPERATING COSTS (IOC):			
Overhead	60% of oper. labor & maintenance	97,100	123,303
Property Taxes	1% of total capital investment	40,093	54,650
Insurance	1% of total capital investment	40,093	54,650
Administration	2% of total capital investment	80,185	109,300
Total IOC:		257,471	341,903
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.09439 times TCI (20 yrs @ 7%)	378,435	515,842
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	860,810	1,287,507
BASELINE NO_x EMISSIONS (TPY):	Max. No. 6 fuel oil with remainder bark. 80% C.F. 0.27 lb/MMBtu for fuel oil and 0.24 lb/MMBtu for bark (90% C.F. = 496.5 TPY)	441.3 [d]	441.3 [d]
MAXIMUM NO_x EMISSIONS (TPY):	20% reduction without reagent (vendor email Dec. 22, 2005) 60% (wood/bark), 40% (fuel oil) reduction with reagent 80% C.F.: (349.5*0.4)+(91.8*0.6)	353.1	173.2
REDUCTION IN NO_x EMISSONS (TPY):		88.3	268.1
COST EFFECTIVENESS:	$ per ton of NO_x Removed	9,752	4,802

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect EPA Air Pollution Cost Control Manual, Sixth Edition (EPA/452/B-02-001, Jan. 2002).

[b] Ecotube NOx Reduction and Combustion Improvement System, Synterprise, LLC, December 21, 2005.

[c] Based on quote from Colonial Chemical Company for 40% liquid urea for January 2006.

[d] Based on annual NOx emissions of 496.5 TPY, which is based on maximum emissions from any fuel combination without NCGs/SOGs/DNCGs, see Table B-2 of Appendix B (0.27 lb/MMBtu for fuel oil and 0.24 lb/MMBtu for bark and 80% C.F). These emissions take into account the 15-percent reduction due to the LNBs.

TABLE 5-10
COST EFFECTIVENESS OF SNCR FOR NO. 4 COMBINATION BOILER, GP PALATKA MILL

Cost Items	Cost Factors[a]	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
SNCR Basic Process	Vendor quote[b]	875,000
NOxOUT Storage Tank	10,000 gallon; included in vendor quote	--
Process Monitoring	15% of equipment cost	131,250
Foundation and Structure Support	8% of equipment cost	70,000
Freight	Vendor quote[b]	12,000
Taxes	Florida sales tax, 6%	52,500
Total PEC:		1,140,750
Direct SNCR Installation	Vendor estimates for similar boiler: 70% of basic	753,375
Total DCC:		1,894,125
INDIRECT CAPITAL COSTS (ICC):		
Air and Water Piping	Based on Engineering Estimate	50,000
Electrical and Controls	Based on Engineering Estimate	50,000
Performance testing	Based on Engineering Estimate	100,000
Engineering and Supervision	Portion performed by GP (5% of Total DCC)	94,706
Modeling	Included in vendor quote	--
Start-up and Optimization Service	Included in vendor quote	--
Temperature Monitoring	Based on Engineering Estimate	45,000
Operation and Maintenance Manuals (5)	Included in vendor quote	--
General Facilities	5% of DCC	94,706
Engineering and home office fees	10% of DCC	189,413
Process Contingency	5% of DCC	94,706
Total ICC:		718,531
PROJECT CONTINGENCY (RETROFIT):	30% of (DCC + ICC)	783,797
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	3,396,453
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	2 hours/week, $16/hr, 52 weeks/yr	1,664
Supervisor	15% of operator cost	250
(2) Maintenance	1.5% of TCI	50,947
(3) NOx-OUT solution cost	18 gal/hr, $1.45/gal[c], 80% C.F.	182,909
(4) Electricity	66 kW, $0.08/kW-hr, 80% C.F.	37,002
(5) Water	520 gph; $0.00064/gal, 80% C.F.	2,332
(6) Fuel- bark/wood (loss in efficiency)	1 MMBtu/yr, $3/MMBtu, 80% C.F.	21,024
Total DOC:		296,128
INDIRECT OPERATING COSTS (IOC):		
Overhead	30% of oper. labor & maintenance	15,858
Property Taxes	0.5% of total capital investment	16,982
Insurance	1% of total capital investment	33,965
Administration	1% of total capital investment	33,965
Total IOC:		100,769
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.09439 times TCI (20 yrs @ 7%)	320,591
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	717,488
BASELINE NO_x EMISSIONS (TPY) :	Max. No. 6 fuel oil with remainder bark. 80% C.F. 0.27 lb/MMBtu for fuel oil and 0.24 lb/MMBtu for bark (90% C.F. = 496.5 TPY)	441.3 [d]
MAXIMUM NO_x EMISSIONS w/SNCR (TPY) :	30% reduction	308.9
REDUCTION IN NO_x EMISSONS (TPY):		132.4
COST EFFECTIVENESS:	$ per ton of NO_x Removed	5,419

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect EPA Air Pollution Cost Control Manual, Sixth Edition (EPA/452/B-02-001, Jan. 2002).

[b] NOxOUT SNCR NOx Reduction System Proposal, FuelTech, Inc., January 5, 2006.

[c] NOxOUT solution cost based on actual cost incurred by U.S. Sugar Corporation for their SNCR system, as of January 2006.

[d] Based on annual NOx emissions of 496.5 TPY, which is based on maximum emissions from any fuel combination without NCGs/SOGs/DNCGs, see Table B-2 of Appendix B (0.27 lb/MMBtu for fuel oil and 0.24 lb/MMBtu for bark and 80% C.F). These emissions take into account the 15-percent reduction due to the LNBs.

TABLE 5-11
COST EFFECTIVENESS OF FGR FOR NO. 4 COMBINATION BOILER, GP PALATKA MILL

Cost Items	Cost Factors[a]	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
FGR Basic Process	Actual Cost[b]	500,000
Fan		200,000
Phase 1 Boiler Study	Actual Cost[b]	40,000
Computational Liquid Dynamics Modeling	Actual Cost[b]	25,000
Process Monitoring	15% of equipment cost	75,000
Structure Support	Included in vendor quote	--
Taxes	Florida sales tax, 6%	30,000
Total PEC:		870,000
Direct FGR Installation	Vendor estimates for similar boiler: 70% of basic	588,000
Total DCC:		1,458,000
INDIRECT CAPITAL COSTS (ICC):		
Air Piping	Included in vendor quote	--
Electrical and Controls	Included in vendor quote	--
Performance testing	Based on Engineering Estimate	25,000
Temperature monitoring	Based on Engineering Estimate	45,000
Engineering and Supervision	Included in vendor quote	--
General Facilities	Included in vendor quote	--
Engineering and home office fees	Included in vendor quote	--
Process Contingency	5% of DCC	72,900
Total ICC:		142,900
PROJECT CONTINGENCY (RETROFIT):	30% of (DCC + ICC)	480,270
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	2,081,170
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	2 hours/week, $16/hr, 52 weeks/yr	1,664
Supervisor	15% of operator cost	250
(2) Maintenance	1.5% of TCI	31,218
(3) Electricity	100 kW, $0.08/kW-hr, 80% C.F.	56,064
Total DOC:		89,195
INDIRECT OPERATING COSTS (IOC):		
Overhead	30% of oper. labor & maintenance	9,939
Property Taxes	0.5% of total capital investment	10,406
Insurance	1% of total capital investment	20,812
Administration	1% of total capital investment	20,812
Total IOC:		61,969
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.09439 times TCI (20 yrs @ 7%)	196,442
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	347,605
BASELINE NO_x EMISSIONS (TPY) :	Maximum bark. 80% C.F. 0.24 lb/MMBtu for bark	431.2
MAXIMUM NO_x EMISSIONS w/FGR (TPY) :	15% reduction	366.5
REDUCTION IN NO_x EMISSONS (TPY):		64.7
COST EFFECTIVENESS:	$ per ton of NO_x Removed	5,374

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect EPA Air Pollution Cost Control Manual, Sixth Edition (EPA/452/B-02-001, Jan. 2002).

[b] Cost of installing an FGR system is based on an approximated value from vendor of $500,000.

TABLE 5-12
BACT DETERMINATIONS FOR CO EMISSIONS FROM BIOMASS-FIRED INDUSTRIAL BOILERS

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits As Provided in LAER/BACT Clearinghouse	 Converted to lb/MMBtu[a]	Control Equipment Description
Georgia-Pacific Corp.--Old Town	ME	A-180-71-AI-A	7/28/2004	265.2 MMBtu/hr	0.35 lb/MMBtu (30-day) 0.45 lb/MMBtu (24-hr)	0.35	Overfire air
U.S. Sugar Corp. - Clewiston Blr No. 8	FL	PSD-FL-333[b]	11/21/2003	1,030 MMBtu/hr	0.38 lb/MMBtu	0.38	Good Combustion Practices
Martinsville Thermal, LLC - Thermal Ventures	VA	VA-0268	2/15/2002	120 MMBtu/hr	0.44 lb/MMBtu	0.44	Good Combustion Practices
Atlantic Sugar Association - Blr No. 5	FL	PSD-FL-078B[c]	6/7/2001	255.3 MMBtu/hr	6.5 lb/MMBtu	6.5	Good Combustion Practices
US Sugar Corp. - Clewiston Blr No. 4	FL	PSD-FL-272A[c]	5/18/2001	633 MMBtu/hr	6.5 lb/MMBtu	6.5	Good combustion practices
International Paper Company - Riegelwood Mill	NC	NC-0092	5/10/2001	600 MMBtu/hr	0.5 lb/MMBtu	0.5	Good Combustion Practices
Gulf States Paper Corp.	AL	AL-0122	10/14/1998	98 MMBtu/hr	0.5 lb/MMBtu	0.5	
Archer Daniels Midland Co. - Northern	ND	ND-0018	7/9/1998	200 MMBtu/hr	0.24 lb/MMBtu	0.24	
Wellborn Cabinet Inc.	AL	AL-0107	2/3/1998	29.5 MMBtu/hr	23.6 lb/hr	0.8	Boiler design & comb. Control: oxygen trim, staged comb., steam injections, & overfire air.
Champion International	AL	AL-0112	12/9/1997	710 MMBtu/hr	0.03 lb/MMBtu	0.03	Proper design and good combustion practices
Plum Creek Mfg. - Evergreen Facility	MT	MT-0007	2/15/1997	225 MMBtu/hr	506 lb/hr	2.25	Good Combustion
Vaughan Furniture Company	VA	VA-0237	8/28/1996	28 MMBtu/hr	104.2 TPY[b]	0.85	No controls feasible
Sugar Cane Growers Coop.	FL	FL-0220	6/4/1996	504 MMBtu/hr	5.5 lb/MMBtu	5.5	Good combustion practices.
Willamette Industries - Marlboro Mill	SC	SC-0045	4/17/1996	470 MMBtu/hr	0.3 lb/MMBtu	0.3	Good combustion control
Plum Creek Mfg. - Columbia Falls Op.	MT	MT-0005	7/26/1995	292.4 MMBtu/hr	468 lb/hr	1.60	Good combustion controls
Weyerhaeuser Company	MS	MS-0026	5/9/1995	90 MMBtu/hr	0.4 lb/MMBtu	0.4	Good combustion controls
U.S. Sugar Corp. - Clewiston Mill	FL	FL-0094	1/31/1995	738 MMBtu/hr	6.5 lb/MMBtu	6.5	Good combustion practices.
Kes Chateaugay Project	NY	NY-0055	12/19/1994	275 MMBtu/hr	0.35 lb/MMBtu	0.35	No controls

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

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

[b] Assuming 8,760 hr/yr.

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

TABLE 5-13
CO CONTROL TECHNOLOGY FEASIBILITY ANALYSIS FOR THE NO. 4 COMBINATION BOILER

CO Abatement Method	Technique Now Available	Estimated Efficiency	Technically Feasible? (Y/N)	Demonstrated? (Y/N)	Rank Based on Control Efficiency	Employed by the No. 4 Combination Boiler? (Y/N)
1. Good Combustion Practices	Furnace Control	>50%	Y	Y	1	Y
2. Incinerators	Thermal	>80%	N	NA	NA	N
	Catalytic	>80%	N	NA	NA	N
3. Combustion Modification	Overfire air	<25%	Y	Y	2	Y

Note: NA = Not Applicable

TABLE 5-14
BACT DETERMINATIONS FOR VOC FOR BIOMASS-FIRED INDUSTRIAL BOILERS

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits As Provided in LAER/BACT Clearinghouse	Emission Limits Converted to lb/MMBtu[a]	Control Equipment Description
Industrial Boilers							
Martinsville Thermal LLC - Thermal Ventures	VA	VA-0268	2/15/2002	120 MMBtu/hr	0.50 lb/MMBtu	0.18	Good combustion practices and CEMS
US Sugar Corp.--Clewiston Blr No. 4	FL	PSD-FL-272A[b]	5/18/2001	633 MMBtu/hr	0.50 lb/MMBtu	0.50	Good combustion practices
Internation Paper Co. - Riegelwood Mill	NC	NC-0092	5/10/2001	600 MMBtu/hr	0.21 lb/MMBtu	0.21	Good combustion practices
Atlantic Sugar Association	FL	PSD-FL-078B[c]	6/7/2001	255.3 MMBtu/hr	0.25 lb/MMBtu	0.25	Wet scrubbers/good combustion practices
Scott Paper Company	WA	WA-0276	10/14/1998	718 MMBtu/hr	34.5 lb/hr	0.05	Combustion control, boiler design
Gulf States Paper Corp.	AL	AL-0122	10/14/1998	98 MMBtu/hr	0.1 lb/MMBtu	0.1	Multicyclone and ESP
Sierra Pacific Industries--Quincy	CA	CA-0930	5/13/1998	245.3 MMBtu/hr	12.3 lb/hr	0.05	High pressure overfire air
Gulf States Paper Corp.	AL	AL-0116	12/10/1997	775 MMBtu/hr	0.03 lb/MMBtu	0.03	Proper boiler design and operation
Champion International	AL	AL-0112	12/9/1997	710 MMBtu/hr	0.03 lb/MMBtu	0.03	Good design and operation
Vaughan Furniture Company	VA	VA-0237	8/28/1996	28 MMBtu/hr	1.7 TPY	--	Combustion control, boiler design
Willamette Industries - Marlboro Mill	SC	SC-0045	4/17/1996	470 MMBtu/hr	0.1 lb/MMBtu	0.1	Good combustion control
Southern Soya Corporation	SC	SC-0035	10/2/1995	58.2 MMBtu/hr	0.05 lb/MMBtu	0.05	Good combustion practices
Plum Creek Mfg. - Columbia Falls Op.	MT	MT-0004	7/26/1995	50 MMBtu/hr	131.1 lb/hr	2.62	Good combustion practices
Kes Chateaugay Project	NY	NY-0055	12/19/1994	275 MMBtu/hr	0.1 lb/MMBtu	0.1	No controls
Plum Creek MFG LP-Columbia Falls Op'n	MT	MT-0004	10/28/1994	50 MMBtu/hr	131.1 lb/hr	2.6	Good combustion practices
Weyerhaeuser Co.	AL	AL-0079	10/28/1994	91 MMBtu/hr	0.05 lb/MMBtu	0.05	--
Weyerhaeuser Co.	AL	AL-0079	7/1/1993	91 MMBtu/hr	0.05 lb/MMBtu	0.05	--
Gulf States Paper Corp	AL	AL-0122	7/1/1993	98 MMBtu/hr	0.1 lb/MMBtu	0.1	Multicyclone and ESP

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2006.

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

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

TABLE 5-15
VOC CONTROL TECHNOLOGY FEASIBILITY ANALYSIS FOR THE NO. 4 COMBINATION BOILER

VOC Abatement Method	Technique Now Available	Estimated Efficiency	Technically Feasible? (Y/N)	Demonstrated? (Y/N)	Rank Based on Control Efficiency	Employed by the No. 4 Combination Boiler? (Y/N)
1. Good Combustion Practices	Furnace Control	>50%	Y	Y	2	Y
2. Post-Combustion Controls	Oxidation Catalyst	70-95%	N	Y	1	N

Note: NA = Not Applicable

TABLE 5-16
BACT DETERMINATIONS FOR SULFURIC ACID MIST FOR BIOMASS-FIRED INDUSTRIAL BOILERS

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits As Provided in LAER/BACT Clearinghouse	Emission Limits Converted to lb/MMBtu[a]	Control Equipment Description
Grayling Generating Station L.P.	MI	882-89E	9/18/2001	523 MMBtu/hr	0.003 lb/MMBtu	0.003	Multicyclones, ESP, SNCR
Mead Containerboard	AL	AL-0099	1/15/1997	620 MMBtu/hr	0.001 lb/MMBtu	0.001	Combustion Control

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2006.

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

TABLE 5-17
SAM CONTROL TECHNOLOGY FEASIBILITY ANALYSIS FOR THE NO. 4 COMBINATION BOILER

SAM Abatement Method	Technique Now Available	Estimated Efficiency	Technically Feasible? (Y/N)	Demonstrated? (Y/N)	Rank Based on Control Efficiency	Employed by the No. 4 Combination Boiler? (Y/N)
1. Good Combustion Practices	Furnace Control	>50%	Y	Y	3	Y
2. Wet Scrubber	Venturi	85-98%	N	Y	2	N
3. Electrostatic Precipitators (ESP)	Dry ESP	>99%	Y	Y	1	Y
	Wet ESP	>99%	Y	Y	1	N

6.0 REFERENCES

Ashenden, T.W. and I.A.D. Williams. 1980. Growth Reductions on *Lolium multiflorum* Lam. and *Phleum pratense* L. as a Result of SO_2 and NO_2 pollution. Environ. Pollut. Ser. A. 21:131-139.

Auer, A.H., 1978. Correlation of Land Use and Cover with Meteorological Anomalies. J. Applied Meteorology, Vol. 17.

Carlson, R.W. 1979. Reduction in the Photosynthetic Rate of *Acer quercus* and *Fraxinus* Species Caused by Sulfur Dioxide and Ozone. Environ. Pollut. 18:159-170.

Hart, R., P.G. Webb, R.H. Biggs, and K.M. Portier. 1988. The Use of Lichen Fumigation Studies to Evaluate the Effects of New Emission Sources on Class I Areas. J. Air Poll. Cont. Assoc. 38:144-147.

Heck, W.W. and D.T. Tingey. 1979. Nitrogen Dioxide: Time-Concentration Model to Predict Acute Foliar Injury. EPA-600/3-79-057, U.S. Environmental Protection Agency, Corvallis, OR.

Holzworth, G.C., 1972. Mixing Heights, Wind Speeds and Potential for Urban Air Pollution Throughout the Contiguous United States. Pub. No. AP-101. U.S. Environmental Protection Agency.

Huber, A.H. and W.H. Snyder, 1976. Building Wake Effects on Short Stack Effluents. Preprint Volume for the Third Symposium on Atmospheric Diffusion and Air Quality, American Meteorological Society, Boston, Massachusetts.

Malhotra, S.S. and A.A. Kahn. 1978. Effect of Sulfur Dioxide Fumigation on Lipid Biosynthesis in Pine Needles. Phytochemistry 17:241-244.

Mandoli, B.L. and P.S. Dubey. 1988. The Industrial Emission and Plant Response at Pithampur (M.P.). Int. J. Ecol. Environ. Sci. 14:75-79.

Matsumaru, T., T. Yoneyama, T. Totsuka, and K. Shiratori. 1979. Absorption of Atmospheric NO_2 by Plants and Soils. Soil Sci. Plant Nutr. 25:255-265.

McLaughlin, S.B. and N.T. Lee. 1974. Botanical Studies in the Vicinity of the Widows Creek Steam Plant. Review of Air Pollution Effects Studies, 1952-1972, and Results of 1973 Surveys. Internal Report I-EB-74-1, TVA.

Naik, R.M., A.R. Dhage, S.V. Munjal, P. Singh, B.B. Desai, S.L. Mehta, and M.S. Naik. 1992. Differential Carbon Monoxide Sensitivity of Cytochrome c Oxidase in the Leaves of C3 and C4 Plants. Plant Physiology 98:984-987.

Newman, J.R. 1981. Effects of Air Pollution on Animals at Concentrations at or Below Ambient Air Standards. Performed for Denver Air Quality Office, National Park Service, U.S. Department of the Interior. Denver, Colorado.

Newman, J.R. and R.K. Schreiber. 1988. Air Pollution and Wildlife Toxicology. Environmental Toxicology and Chemistry. 7:381-390.

Pollok, M., U. Hever, and M.S. Naik. 1989. Inhibition of stomatal opening in sunflower leaves by carbon monoxide and reversal of inhibition by light. Planta 178:223-230.

U.S. Department of Agriculture, Soil Conservation Service. 1981. Soil Survey of Pasco County, Florida.

U.S. Environmental Protection Agency. 1978. Guidelines for Determining Best Available Control Technology (BACT). Office of Air Quality Planning and Standards.

U.S. Environmental Protection Agency. 1980. Prevention of Significant Deterioration Workshop Manual.

U.S. Environmental Protection Agency (EPA). 1982. Air Quality Criteria for Particulate Matter and Sulfur Oxides. Vol. 3.

U.S. Environmental Protection Agency. 1987. Ambient Monitoring Guidelines for Prevention of Significant Deterioration. EPA Report No. EPA 450/4-87-007.

U.S. Environmental Protection Agency. 1990. "Top-Down" Best Available Control Technology Guidance Document (Draft). Research Triangle Park, North Carolina.

U.S. Environmental Protection Agency. 1999. Letter from P. Douglas Neeley, Chief Air and Radiation Technology Branch, EPA Region IV, Atlanta, GA (November 10, 1999).

U.S. Environmental Protection Agency. 2001. Industrial Source Complex- PRIME (ISC-PRIME) Dispersion Model (Version 01228). Updated from Technical Transfer Network.

Woltz, S.S. and T.K. Howe. 1981. Effects of Coal Burning Emissions on Florida Agriculture. In: The Impact of Increased Coal Use in Florida. Interdisciplinary Center for Aeronomy and (other) Atmospheric Sciences. University of Florida, Gainesville, Florida.

Zahn, R. 1975. Gassing Experiments with NO_2 in Small Greenhouses. Staub Reinhalt. Luft 35:194-196

APPENDIX A

PAST ACTUAL SHORT-TERM EMISSION RATE CALCULATIONS FOR NO. 4 COMBINATION BOILER AND NO. 4 POWER BOILER

TABLE A-1
PAST ACTUAL (2004-2005) 24-HOUR EMISSIONS FOR HIGHEST BARK/WOOD BURNING DAY (MARCH 11, 2004) FOR THE NO. 4 COMBINATION BOILER, GP PALATKA MILL

	Wood/Bark				No. 6 Fuel Oil				
Regulated Pollutant	Emission Factor	Ref.	24-Hour Activity Factors [a]	24-Hr Average Emissions [b] (lb/hr)	Emission Factor	Ref.	24-Hour Activity Factors [c]	24-Hr Average Emissions [d] (lb/hr)	Total Emissions (lb/hr)
Particulate (PM)	0.066 lb/MMBtu	1	47.1 tons bark/hr	27.99	0.04 lb/MMBtu	4	41,932 lbs/day	1.28	29.27
Particulate (PM_{10})	74 % of PM	2	--	20.71	63 % of PM	5	--	0.81	21.52
Carbon monoxide	5.4 lb/ton WWF	3	47.1 tons bark/hr	254.46	5 lb/1,000 gal	6	41,932 lbs/day	1.07	255.52
Nitrogen oxides	0.24 lb/MMBtu	7	423.9 MMBtu/hr	101.74	47 lb/1,000 gal	6	41,932 lbs/day	10.01	111.75
Sulfur dioxide	0.225 lb SO_2/ton WWF	3	47.1 tons bark/hr	10.6	0.164 (S) lb/gal	9	41,932 lbs/day	76.9	87.48
Sulfuric acid mist	4.4 % of SO_2	8	--	0.47	4.4 % of SO_2	8	--	3.38	3.85

Notes:

[a] Based on actual maximum daily bark usage (1,130.92 tons bark/day) on March 11, 2004.

[b] Hourly emissions based on emission factor, maximum tons of bark burned, and 9 MMBtu/ton of bark.

[c] Based on oil usage of 41,932 lbs/day on March 11, 2004.

[d] Hourly emissions based on emission factor, 24 hours per day, maximum fuel oil usage, 8.2 lb/gal, and 150,000 Btu/gal.

References:

1. Based on average of last two years of stack test data when buring bark/wood (8/18/05 and 1/8/04).
2. PM_{10} estimated to be 74% of PM based on the ratio of individual emission factors for PM and PM_{10} from AP-42 Table 1.6-1 for wood-residue fired boilers with an ESP.
3. Emission factor based on AP-42 Section 1.6 Table 1.6-1 (3/02). Emission factor converted from lb/MMBtu to lb/ton of wood/bark by multiplying by 9 MMBtu/ton (CO = 0.60 lb/MMBtu and SO_2 = 0.025 lb/MMBtu).
4. Emission factor based on last two years of stack test data when burning fuel oil only (8/22/05 and 1/8/04).
5. Based on AP-42 Section 1.3, Table 1.3-4, for utility boilers firing residual oil with an ESP (no factor available for industrial boilers with an ESP).
6. Emission factor based on AP-42 Section 1.3 Table 1.3-1 (9/98).
7. Based on estimated current NO_x emissions due to bark/wood firing, on a lb/MMBtu basis.
8. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).
9. Emission factor based on AP-42, Section 1.3, Table 1.3-1. S = 2.2 % (average actual sulfur content for 2004 and 2005).

TABLE A-2
PAST ACTUAL (2004-2005) 24-HOUR EMISSIONS FOR HIGHEST FUEL OIL BURNING DAY (JANUARY 17, 2005) FOR THE NO. 4 COMBINATION BOILER, GP PALATKA MILL

	Wood/Bark				No. 6 Fuel Oil				Total
Regulated Pollutant	Emission Factor	Ref.	24-Hour Activity Factors [a]	24-Hr Average Emissions [d] (lb/hr)	Emission Factor	Ref.	24-Hour Activity Factors [b]	24-Hr Average Emissions [c] (lb/hr)	24-Hour Emissions (lb/hr)
Particulate (PM)	0.066 lb/MMBtu	1	0.00 tons/day	0.00	0.04 lb/MMBtu	7	20,230 lbs oil/hr	14.80	14.80
Particulate (PM_{10})	74 % of PM	2	--	0.00	63 % of PM	8	--	9.33	9.33
Carbon monoxide	5.4 lb/ton WWF	3	0.00 tons/day	0.00	5 lb/1,000 gal	5	20,230 lbs oil/hr	12.34	12.34
Nitrogen oxides	0.24 lb/MMBtu	4	0.00 MMBtu/hr	0.00	47 lb/1000 gal	5	20,230 lbs oil/hr	115.95	115.95
Sulfur dioxide	0.225 lb/ton WWF	3	0.00 tons/day	0.00	0.164 (S) lb/gal	5	20,230 lbs oil/hr	890.1	890.13
Sulfuric acid mist	4.4 % of SO_2	6	--	0.00	4.4 % of SO_2	6	--	39.17	39.17

Notes:

[a] No wood/bark was burned on the highest fuel oil usage day (January 17, 2005).

[b] Based on highest fuel oil usage day from 2004-2005 (485,524 lbs/day on 1/17/05).

[c] Hourly emissions based on emission factor, 24 hours per day, maximum fuel oil usage, 8.2 lb/gal, and 150,000 Btu/gal.

[d] Hourly emissions based on emission factor, maximum tons of bark burned, and 9 MMBtu/ton of bark.

References:

1. Based on average of last two years of stack test data when buring bark/wood (8/18/05 and 1/8/04).
2. PM_{10} estimated to be 74% of PM based on the ratio of individual emission factors for PM and PM_{10} from AP-42 Table 1.6-1 for wood-residue fired boilers with an ESP.
3. Emission factor based on AP-42 Section 1.6 Table 1.6-1 (3/02). Emission factor converted from lb/MMBtu to lb/ton of wood/bark by multiplying by 9 MMBtu/ton (CO = 0.60 lb/MMBtu and SO_2 = 0.025 lb/MMBtu).
4. Based on current estimated NO_x emissions due to bark/wood firing, on a lb/MMBtu basis.
5. Emission Factors based on AP-42, Section 1.3, Table 1.3-1. S = 2.2 % (average actual sulfur content for 2004 and 2005).
6. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).
7. Emission factor based on last two years of stack test data when burning fuel oil only (8/22/05 and 1/8/04).
8. Based on AP-42 Section 1.3, Table 1.3-4, for utility boilers firing residual oil with an ESP (no factor available for industrial boilers with an ESP).

TABLE A-3
PAST ACTUAL (2001-2002) 24-HOUR EMISSIONS FOR HIGHEST FUEL OIL BURNING DAY (NOVEMBER 4, 2002) FOR THE NO. 4 POWER BOILER, GP PALATKA MILL

	No. 6 Fuel Oil			
Regulated Pollutant	Emission Factor	Ref.	24-Hour Activity Factors	24-Hr Average Emissions (lb/hr)
Sulfur dioxide	0.157 (S) lb/gal	1	832 gal oil/hr [a]	287.3
Sulfuric acid mist	4.4 % of SO_2	2	--	12.64
Nitrogen oxides	47 lb/1000 gal	1	832 gal oil/hr [a]	39.09
Particulate (PM)	23.40 lb/1000 gal	1	832 gal oil/hr [a]	19.46
Particulate (PM_{10})	86 % of PM	3	--	16.74
Carbon monoxide	5 lb/1,000 gal	1	832 gal oil/hr [a]	4.16

Note: Highest 24-hour oil usage during 2001 through 2002 were determined to have occurred on November 14, 2002.

[a] Based on fuel oil usage of 19,962 gal/day on 11/14/02 actual operation. (150,000 Btu/gal).

References:

1. Emission Factors based on AP-42 Section 1.3 Table 1.3-1. S = 2.2 % (average actual sulfur content for 2001 and 2002).
2. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).
3. Based on AP-42 Section 1.3, Table 1.3-5, for industrial boilers firing residual oil with no control.

APPENDIX B

POTENTIAL EMISSION RATE CALCULATIONS FOR THE NO. 4 COMBINATION BOILER

TABLE B-1
FUTURE POTENTIAL ANNUAL EMISSIONS FOR INDIVIDUAL FUELS, NO. 4 COMBINATION BOILER, GP PALATKA

	No. 6 Fuel Oil				Wood/Bark				NCGs/SOG/DNCGs			
Regulated Pollutant	Emission Factor	Ref.	Activity Factors [a]	Annual Emissions (TPY)	Emission Factor	Ref.	Activity Factors [b]	Annual Emissions (TPY)	Emission Factor	Ref.	Activity Factors	Annual Emissions (TPY)
Particulate (PM)	0.04 lb/MMBtu	1	5,100,000 gal/yr	15.30	0.04 lb/MMBtu	1	4,042,127 MMBtu/yr	80.84	--	--	--	--
Particulate (PM$_{10}$)	63 % of PM	2	--	9.64	74 % of PM	6	--	59.82	--	--	--	--
Sulfur dioxide:	0.164 (S) lb/gal	3	5,100,000 gal/yr; 0% removal	982.77	0.025 lb/MMBtu	6	4,042,127 MMBtu/yr	50.53	785.0 tons/yr	7	--	785.0
Nitrogen oxides	0.27 lb/MMBtu	10	5,100,000 gal/yr	103.28	0.24 lb/MMBtu	11	4,042,127 MMBtu/yr	485.06	0.9 lb/1000 gal condensate	8	48,000 gal/hr [c]	37.84
Carbon monoxide	5 lb/Mgal	4	5,100,000 gal/yr	12.75	0.50 lb/MMBtu	6	4,042,127 MMBtu/yr	1,010.53	--	--	--	--
VOC	0.28 lb/Mgal	4	5,100,000 gal/yr	0.71	0.017 lb/MMBtu	6	4,042,127 MMBtu/yr	34.36	--	--	--	--
Sulfuric acid mist	4.4 % of SO$_2$	5	--	43.24	4.4 % of SO$_2$	5	--	2.22	4.4 % of SO$_2$	5	--	34.54
Total reduced sulfur	--		--	--	--		--	--	5 ppmvd @ 10% O$_2$	9	135,400 dscfm	15.70
Lead	1.51E-03 lb/Mgal	4	5,100,000 gal/yr	3.85E-03	4.80E-05 lb/MMBtu	6	4,042,127 MMBtu/yr	9.70E-02	--	--	--	--
Mercury	1.13E-04 lb/Mgal	4	5,100,000 gal/yr	2.88E-04	3.50E-06 lb/MMBtu	6	4,042,127 MMBtu/yr	7.07E-03	--	--	--	--
Fluorides	3.73E-02 lb/Mgal	4	5,100,000 gal/yr	9.51E-02	--	--	--	--	--	--	--	--

Notes:

TWWF - tons of wet wood residue fuel

NCGs= non-condensable gases; SOG= stripper off-gas; DNCGs= dilute NCGs.

Natural gas emissions not shown since it is a start up fuel only.

Footnotes:

[a] Based on proposed annual fuel oil limit of 5,100,000 gal/yr or 765,000 MMBtu/yr, based on 150,000 Btu/gal for fuel oil.

[b] Based on an annual capacity factor of 90% (461.43 MMBtu/hr and 425,487 TPY) of the 24-hour heat input limit of 512.7 MMBtu/hr in Permit No. 1070005-023-AV; or 425,487 TPY, wet, based on 4,750 Btu/lb and 8,760 hr/yr.

[c] Design rate of 800 gpm for condensate stripper.

References:

1. Proposed BACT limit.
2. Based on AP-42 Section 1.3, Table 1.3-4, for utility boilers firing residual oil with an ESP (no factor available for industrial boilers with an ESP).
3. Based on current permit condition (Permit No. 1070005-023-AV). Does not include emissions due to NCG/SOG/DNCG burning. S = 2.35%.
4. Emission Factors based on AP-42 Section 1.3 Table 1.3-1, 1.3-3, 1.3-4 and 1.3-11 for metals (assuming uncontrolled for metals) (9/98).
5. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3.6% of SO$_2$ becomes SO$_3$ then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).
6. Emission Factors based on AP-42 Section 1.6 Tables 1.6-1, 1.6-2, 1.6-3, and 1.6-4 (9/03). PM$_{10}$ estimated to be 74% of PM based on the ratio of individuals emission factors for PM and PM$_{10}$ from AP-42 Table 1.6-1 for wood-residue fired boilers with an ESP.
7. Based on maximum emissions due to NCGs/SOG/DNCGs combustion in the No. 4 Combination Boiler.
8. Based on MACT I permit revision application (11/01).
9. Based on construction permit for Brown Stock Washer/O$_2$ Delig. System (July 2004).
10. Based on the AP-42 factor for boilers greater than 100 MMBtu/hr with normal firing with low-NO$_x$ burners (Table 1.3-1).
11. Emission factor based on no increase in current NOx emissions due to bark/wood firing, on a lb/MMBtu basis. Emission factor represents average of October 2005 test for wood/bark firing
12. TRS emissions are not expected to increase as a result of these projects.

TABLE B-2
MAXIMUM FUTURE POTENTIAL ANNUAL EMISSIONS FOR DIFFERENT FUEL SCENARIOS, NO. 4 COMBINATION BOILER, GP PALATKA

	No. 6 Fuel Oil Only[a]	Wood/Bark Only[a]	Max No. 6 Fuel Oil w/ Remainder Wood/Bark[b]	NCGs/SOG/DNCGs Only [a]	Maximum Emissions for Any Fuel Combination	
Regulated Pollutant	Annual Emissions (TPY)	Annual Emissions (TPY)	Annual Emissions (TPY)	Annual Emissions (TPY)	with NCGs/SOG/DNCGs (TPY)	without NCGs/SOG/DNCGs (TPY)
Particulate (PM)	15.30	80.84	80.84	--	80.8	80.8
Particulate (PM_{10})	9.64	59.82	59.82	--	59.8	59.8
Sulfur dioxide	982.77	50.53	1,023.73	785	1,808.7	1,023.7
Nitrogen oxides	103.28	485.06	496.53	37.84	534.4	496.5
Carbon monoxide	12.75	1,010.53	832.03	--	1,010.5	1,010.5
VOC	0.71	34.36	28.57	--	34.4	34.4
Sulfuric acid mist	43.24	2.22	45.04	34.54	79.6	45.0
Total reduced sulfur	--	--	--	15.70	15.7	--
Lead	3.85E-03	9.70E-02	1.21E-02	--	9.70E-02	9.70E-02
Mercury	2.88E-04	7.07E-03	8.92E-04	--	7.07E-03	7.07E-03
Fluorides	9.51E-02	--	9.51E-02	--	9.51E-02	9.51E-02

Footnotes:

[a] Based on Table B-1.

[b] Based on emissions due to fuel oil plus the remainder of the year burning wood/bark:

Total Heat Input =	4,042,127	MMBtu/yr
Maximum Fuel Oil Usage =	5,100,000	gal/yr
Heat Input Due to Wood/Bark =	3,277,127	MMBtu/yr
Wood/Bark Usage =	344,961	tons/yr

TABLE B-3
FUTURE POTENTIAL HOURLY EMISSIONS FOR INDIVIDUAL FUELS, NO. 4 COMBINATION BOILER, GP PALATKA

	No. 6 Fuel Oil				Wood/Bark				NCGs/SOG/DNCGs			
Regulated Pollutant	Emission Factor	Ref.	Activity Factors [a]	Hourly Emissions (lb/hr)	Emission Factor	Ref.	Activity Factors [b]	Hourly Emissions (lb/hr)	Emission Factor	Ref.	Activity Factors	Hourly Emissions (lb/hr)
Particulate (PM)	0.04 lb/MMBtu	1	418.6 MMBtu/hr	16.74	0.04 lb/MMBtu	1	564 MMBtu/hr	22.56	--	--	--	--
Particulate (PM_{10})	63 % of PM	2	--	10.55	74 % of PM	6	--	16.69	--	--	--	--
Sulfur Dioxide--24-Hour	0.164 (S) lb/gal	3	2,791 gal/hr	1,075.65	0.025 lb/MMBtu	6	564 MMBtu/hr	14.10	845.9 lb/hr	8	--	845.9
--3-Hour	0.164 (S) lb/gal	3	2,791 gal/hr	1,075.65	0.025 lb/MMBtu	6	564 MMBtu/hr	14.10	1,041.5 lb/hr	8	--	1,041.50
Nitrogen oxides--3-hour	0.27 lb/MMBtu	11	418.6 MMBtu/hr	113.02	0.24 lb/MMBtu	12	564 MMBtu/hr	135.36	0.9 lb/1000 gal condensate	9	48,000 gal/hr [c]	43.20
Carbon monoxide	5 lb/Mgal	4	2.791 Mgal/hr	13.96	0.50 lb/MMBtu	6	564 MMBtu/hr	282.00	--	--	--	--
VOC	0.28 lb/Mgal	4	2.791 Mgal/hr	0.78	0.017 lb/MMBtu	6	564 MMBtu/hr	9.59	--	--	--	--
Sulfuric Acid Mist--24-Hour	4.4 % of SO_2	5	--	47.33	4.4 % of SO_2	5	--	0.62	4.4 % of SO_2	5	--	37.22
--3-Hou	4.4 % of SO_2	5	--	47.33	4.4 % of SO_2	5	--	0.62	4.4 % of SO_2	5	--	45.83
Total reduced sulfur	--		--	--	--	--	--	--	5 ppmvd @ 10% O_2	10	135,400 dscfm	3.60
Lead	1.51E-03 lb/Mgal	4	2.791 Mgal/hr	4.2E-03	3.20E-04 lb/TWWF	7	59.4 tons/hr, wet	1.90E-02	--	--	--	--
Mercury	1.13E-04 lb/Mgal	4	2.791 Mgal/hr	3.2E-04	3.15E-05 lb/TWWF	6	59.4 tons/hr, wet	1.87E-03	--	--	--	--
Beryllium	2.78E-05 lb/Mgal	4	2.791 Mgal/hr	7.8E-05	--	--	--	--	--	--	--	--
Fluorides	3.73E-02 lb/Mgal	4	2.791 Mgal/hr	1.0E-01	--	--	--	--	--	--	--	--

Notes:
TWWF - tons of wet wood residue fuel
NCGs= non-condensable gases; SOG= stripper off-gas; DNCGs= dilute NCGs.
Natural gas emissions not shown since it is a start up fuel only.

Footnotes:

[a] Based on heat input limit of 418.6 MMBtu/hr in Permit No. 1070005-023-AV; or 2.791 Mgal/hr of fuel oil based on 150,000 Btu/gal.

[b] Based on heat input limit of 564 MMBtu/hr (3-hour maximum) or 59.4 tons/hr, wet, based on 4,750 Btu/lb.

[c] Design rate of 800 gpm for condensate stripper.

References:
1. Proposed BACT limit.
2. Based on AP-42 Section 1.3, Table 1.3-4, for utility boilers firing residual oil with an ESP (no factor available for industrial boilers with an ESP).
3. Based on current permit condition (Permit No. 1070005-023-AV). Does not include emissions due to NCG/SOG/DNCG burning. S = 2.35%.
4. Emission Factors based on AP-42 Section 1.3 Table 1.3-1, 1.3-3, 1.3-4 and 1.3-11 for metals (assuming uncontrolled for metals) (9/98).
5. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).
6. Emission Factors based on AP-42 Section 1.6 Tables 1.6-1, 1.6-2, 1.6-3, and 1.6-4 (9/03). PM_{10} estimated to be 74% of PM based on the ratio of individuals emission factors for PM and PM_{10} from AP-42 Table 1.6-1 for wood-residue fired boilers with an ESP. Mercury factor based on conversion from 3.5E-6 lb/MMBtu to lb/ton wood/bark by multiplying by 9 MMBtu/ton.
7. Emission factor from EPA's FIRE system for wood/bark burning with multiple cyclone with fly ash reinjection control.
8. Based on maximum emissions due to NCGs/SOG/DNCGs combustion in the No. 4 Combination Boiler.
9. Based on MACT I permit revision application (11/01).
10. Based on construction permit for Brown Stock Washer/O_2 Delig. System (July 2004).
11. Based on the AP-42 factor for boilers greater than 100 MMBtu/hr with normal firing with low-NO_x burners (Table 1.3-1).
12. Emission factor based on no increase in current NOx emissions due to bark/wood firing, on a lb/MMBtu basis. Emission factor represents average of October 2005 test for wood/bark firing.

TABLE B-4
MAXIMUM FUTURE POTENTIAL HOURLY EMISSIONS FOR DIFFERENT FUEL BURNING SCENARIOS, NO. 4 COMBINATION BOILER, GP PALATKA

Regulated Pollutant	No. 6 Fuel Oil (lb/hr)	Wood/Bark (lb/hr)	NCGs/SOGs/DNCGs (lb/hr)	Maximum Emissions For Any Fuel Combination	
				with NCGs/SOGs/DNCGs (lb/hr)	without NCGs/SOGs/DNCGs (lb/hr)
Particulate (PM)	16.7	22.6	--	22.6	22.6
Particulate (PM_{10})	10.5	16.7	--	16.7	16.7
Sulfur dioxide--3-Hour	1,075.7	14.1	1,041.5	2,117.2	1,075.7
--24-Hour	1,075.7	14.1	845.9	1,921.5	1,075.7
Nitrogen oxides--3-Hour	113.0	135.4	43.2	178.6	135.4
Carbon monoxide	14.0	282.0	--	282.0	282.0
VOC	0.78	9.6	--	9.6	9.6
Sulfuric acid mist--3-Hour	47.3	0.62	45.8	93.2	47.3
--24-Hour	47.3	0.62	37.2	84.5	47.3
Total reduced sulfur	--	--	3.60	3.6	--
Lead	4.21E-03	1.90E-02	--	1.90E-02	1.90E-02
Mercury	3.15E-04	1.87E-03	--	1.87E-03	1.87E-03
Beryllium	7.76E-05	--	--	7.76E-05	7.76E-05
Fluorides	1.04E-01	--	--	1.04E-01	1.04E-01

Reference: Hourly emissions from Table B-3.

ATTACHMENT C

PAST ACTUAL EMISSION RATE CALCULATIONS FOR PROJECT-AFFECTED SOURCES

APPENDIX C

PAST ACTUAL EMISSION RATE CALCULATIONS FOR PROJECT-AFFECTED SOURCES

General Assumptions:

Past actual emission calculations have been calculated by taking the average values of either Mill production and/or combustion equipment fuel usage data for calendar years 2004 and 2005 and multiplying these average values by the appropriate emission factors. Emission factors used include those published in US Environmental Protection Agency (EPA) Manual AP-42, various technical bulletins and other reports published by the National Council for Air and Stream Improvement (NCASI). Additionally, some of the baseline emission data is taken directly from stack tests that have been performed. Some of the production and/or fuel usage data come from the Mill's 2004 and 2005 Annual Operating Reports submitted to the state while some of the data comes from other Mill records.

The pollutants considered for emission estimating purposes include: particulate matter (total particulate matter and PM_{10}), nitrogen oxides, sulfur dioxide, carbon monoxide, volatile organic compounds, lead, total reduced sulfur, sulfuric acid mist, mercury, and beryllium.

Chemical Recovery

No. 4 Recovery Boiler- Emissions Unit ID # 018 - Rated capacity of 210,000 lb/hr of BLS or 5.04 MM lb BLS/day. Unit uses an ESP with a particulate matter collection efficiency of 99%.

2004: 525,988 tons air-dried unbleached pulp or 744,438 tons BLS
Hours of operation: 8,082

2005: 534,339 tons air-dried unbleached pulp or 766,071tons BLS
Hours of operation: 8,283

Particulate Matter Emissions:

2004:

$$\text{PM(hourly)} = 52.7\ \frac{\text{lb}}{\text{hr}}\ \text{- Stack Test Data 3/2/2004}$$

$$\text{PM(annual)} = \left(52.7\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}082\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 213.0\,\text{TPY}$$

2005:

$$\text{PM(hourly)} = 13.6\ \frac{\text{lb}}{\text{hr}}\ \text{- Stack Test Data 9/6-7/2005}$$

$$\text{PM(annual)} = \left(13.6\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}283\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 56.3\ \text{TPY}$$

Average:

PM (hourly) = 33.2 lb/hr

$$\text{PM(annual)} = 134.7\ \text{TPY}$$

Particulate Matter (PM_{10}) Emissions: AP-42, Table 10.2-3 (9/90), indicates that PM_{10} emissions from recovery boilers without a direct contact evaporator and with an ESP control device are equivalent to 75% of PM emissions.

2004:

$$\text{PM}_{10}\text{(hourly)} = 0.75\left(52.7\frac{\text{lb}}{\text{hr}}\right) = 39.5\ \frac{\text{lb}}{\text{hr}}$$

$$\text{PM}_{10}\text{(annual)} = 0.75(213\,\text{TPY}) = 159.8\ \text{TPY}$$

2005:

$$\text{PM}_{10}\text{(hourly)} = 0.75\left(13.6\frac{\text{lb}}{\text{hr}}\right) = 10.2\ \frac{\text{lb}}{\text{hr}}$$

$$\text{PM}_{10}\text{(annual)} = 0.75(56.3\,\text{TPY}) = 42.2\ \text{TPY}$$

Average:

$$PM_{10}(\text{hourly}) = 24.9\ \frac{\text{lb}}{\text{hr}}$$

$$PM_{10}(\text{annual}) = 101.0\ \text{TPY}$$

Sulfur Dioxide Emissions:

2004:

$$SO_2(\text{hourly}) = 4.3\ \frac{\text{lb}}{\text{hr}}\ \text{- Stack Test Data 3/2/2004}$$

$$SO_2(\text{annual}) = \left(4.3\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}082\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 17.4\ \text{TPY}$$

2005:

$$SO_2(\text{hourly}) = 2.9\ \frac{\text{lb}}{\text{hr}}\ \text{- Based on annual average of CEMS data for 2005, excluding SSM}$$

$$SO_2(\text{annual}) = \left(2.9\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}283\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 12.0\ \text{TPY}$$

Average:

$$SO_2(\text{hourly}) = 3.6\ \frac{\text{lb}}{\text{hr}}$$

$$SO_2(\text{annual}) = 14.7\ \text{TPY}$$

Sulfuric Acid Mist Emissions:

2004:

$$\text{SAM}(\text{hourly}) = 0.6\ \frac{\text{lb}}{\text{hr}}\ \text{- Stack Test Data 3/2/2004}$$

$$\text{SAM}(\text{annual}) = \left(0.6\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}082\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 2.4\ \text{TPY}$$

2005:

Estimate based on similar derivation of sulfuric acid mist from AP-42, Table 1.3-1, for fuel oil: 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).

$$\text{SAM}(\text{hourly}) = 0.044\left(2.9\frac{\text{lb}}{\text{hr}}\right) = 0.13\frac{\text{lb}}{\text{hr}}$$

$$\text{SAM}(\text{annual}) = 0.044(12.0\ \text{TPY}) = 0.53\ \text{TPY}$$

Average:

$$\text{SAM}(\text{hourly}) = 0.37\ \frac{\text{lb}}{\text{hr}}$$

$$\text{SAM}(\text{annual}) = 1.5\ \text{TPY}$$

Nitrogen Oxides Emissions:

2004:

$$\mathrm{NO_x\,(hourly)} = 115.0\,\frac{\mathrm{lb}}{\mathrm{hr}} \text{ - Stack Test Data 3/2/2004}$$

$$\mathrm{NO_x\,(annual)} = \left(115.0\,\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}082\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 464.7 \text{ TPY}$$

2005:

$$\mathrm{NO_x\,(hourly)} = 116.3\,\frac{\mathrm{lb}}{\mathrm{hr}} \text{ - Stack Test Data 9/6-7/2004}$$

$$\mathrm{NO_x\,(annual)} = \left(116.3\,\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}283\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 481.7 \text{ TPY}$$

Average:

$$\mathrm{NO_x\,(hourly)} = 115.7\,\frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{NO_x\,(annual)} = 473.2 \text{ TPY}$$

Carbon Monoxide Emissions:

2004:

$$\mathrm{CO(hourly)} = 318.0\,\frac{\mathrm{lb}}{\mathrm{hr}} \text{ - Stack Test Data 3/2/2004}$$

$$\mathrm{CO(annual)} = \left(318.0\,\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}082\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 1{,}285.0 \text{ TPY}$$

2005:

$$\mathrm{CO(hourly)} = 293\,\frac{\mathrm{lb}}{\mathrm{hr}} \text{ - Stack Test Data 9/6-7/2005}$$

$$\mathrm{CO(annual)} = \left(293\,\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}283\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 1{,}213.5 \text{ TPY}$$

Average:

$$\mathrm{CO(hourly)} = 305.5\,\frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{CO(annual)} = 1{,}249.3 \text{ TPY}$$

Volatile Organic Compound Emissions:

2004:

$$\mathrm{VOC(hourly)} = 0.3\,\frac{\mathrm{lb}}{\mathrm{hr}} \text{ - Stack Test Data 3/2/2004}$$

$$\mathrm{VOC(annual)} = \left(0.3\,\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}082\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 1.2 \text{ TPY}$$

2005:

$$\text{VOC(hourly)} = 4.3\frac{\text{lb}}{\text{hr}}\ \text{- Stack Test Data 9/6-7/2005}$$

$$\text{VOC(annual)} = \left(4.3\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}283\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 17.8\,\text{TPY}$$

Average:

$$\text{VOC(hourly)} = 2.3\,\frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = 9.5\,\text{TPY}$$

Total Reduced Sulfur Emissions:

2004:

$$\text{TRS(hourly)} = 2.2\frac{\text{lb}}{\text{hr}}\ \text{- Stack Test Data 3/2/2004}$$

$$\text{TRS(annual)} = \left(2.2\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}082\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 8.9\,\text{TPY}$$

2005:

$$\text{TRS(hourly)} = 3.3\frac{\text{lb}}{\text{hr}}\ \text{- Stack Test Data 9/6-7/2005}$$

$$\text{TRS(annual)} = \left(3.3\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}283\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 13.7\,\text{TPY}$$

Average:

$$\text{TRS(hourly)} = 2.8\,\frac{\text{lb}}{\text{hr}}$$

$$\text{TRS(annual)} = 11.3\ \text{TPY}$$

Lead Emissions: Emission factor - NCASI TB 701, Table 12D = 31.3 lbs Pb/MM ton BLS (median value).

2004:

$$\text{Pb(hourly)} = 31.3\frac{\text{lb}}{\text{MMton}}\left(\frac{744{,}438\,\text{ton}}{\text{yr}}\right)\left(\frac{\text{MMton}}{10^6\,\text{ton}}\right)\left(\frac{\text{yr}}{8{,}082\,\text{hr}}\right) = 0.0029\frac{\text{lb}}{\text{hr}}$$

$$\text{Pb(annual)} = \left(0.0029\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}082\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.012\,\text{TPY}$$

2005:

$$\text{Pb(hourly)} = 31.3\frac{\text{lb}}{\text{MMton}}\left(\frac{766{,}071\,\text{ton}}{\text{yr}}\right)\left(\frac{\text{MMton}}{10^6\,\text{ton}}\right)\left(\frac{\text{yr}}{8{,}282.5\,\text{hr}}\right) = 0.0029\frac{\text{lb}}{\text{hr}}$$

$$\text{Pb(annual)} = \left(0.0029\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}283\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.012\,\text{TPY}$$

Average:

$$\text{Pb(hourly)} = 0.0029\ \frac{\text{lb}}{\text{hr}}$$

$$\text{Pb(annual)} = 0.012\ \text{TPY}$$

Mercury Emissions: Emission factor - NCASI TB 858, Table 14B = $1.8\text{x}10^{-7}$ lb/ton BLS (median value).

2004:

$$\text{Hg(hourly)} = 1.8\text{x}10^{-7}\ \frac{\text{lb}}{\text{ton}}\left(\frac{744{,}438\ \text{ton}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}082\ \text{hr}}\right) = 1.66\text{x}10^{-5}\ \frac{\text{lb}}{\text{hr}}$$

$$\text{Hg(annual)} = \left(1.66\text{x}10^{-5}\ \frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}082\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 6.7\text{x}10^{-5}\ \text{TPY}$$

2005:

$$\text{Hg(hourly)} = 1.8\text{x}10^{-7}\ \frac{\text{lb}}{\text{ton}}\left(\frac{766{,}071\ \text{ton}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}282.5\ \text{hr}}\right) = 1.66\text{x}10^{-5}\ \frac{\text{lb}}{\text{hr}}$$

$$\text{Hg(annual)} = \left(1.66\text{x}10^{-5}\ \frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}283\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 6.9\text{x}10^{-5}\ \text{TPY}$$

Average:

$$\text{Hg(hourly)} = 1.66\text{x}10^{-5}\ \frac{\text{lb}}{\text{hr}}$$

$$\text{Hg(annual)} = 6.8\text{x}10^{-5}\ \text{TPY}$$

Highest Daily PM_{10}, SO_2, SAM, NO_x, CO, and TRS Emission Rates – Used for Modeling Purposes

Highest daily emission rates based on stack test data or as noted below:

lb/hr PM_{10} = 39.5 lb/hr (2004)
lb/hr SAM = 0.6 lb/hr (2004)
lb/hr NO_x = 116.3 lb/hr (2005)
lb/hr CO = 318.0 lb/hr (2004)
lb/hr TRS = 3.3 lb/hr (2005)

lb/hr SO_2:

3-hour average: Based on CEMS data from 9/23/04 – 69 ppmvd
Flow rate based on 2004 stack test: 234,700 dscfm

$$SO_2(3-\text{hour}) =$$

$$\left(\frac{69\ \text{ft}^3}{10^6\ \text{ft}^3}(\text{ppmvd})\right)\left(\frac{234{,}700\ \text{dscf}}{\text{min}}\right)\left(\frac{2{,}116.8\ \text{lb}}{\text{ft}^2}\right)\left(\frac{\text{lb}-\text{mole}-\text{R}}{1{,}545.6\ \text{ft}-\text{lb}_f}\right)\left(\frac{1}{528\ \text{R}}\right)\left(\frac{64\ \text{lb}}{\text{lb}-\text{mole}}\right)\left(\frac{60\ \text{min}}{\text{hr}}\right)=161.3\frac{\text{lb}}{\text{hr}}$$

24-hour average: Based on CEMS data from 7/04/04 – 10.6 ppmvd
Flow rate based on 2004 stack test: 234,700 dscfm

$$SO_2(24-\text{hour}) =$$

$$\left(\frac{10.6\ \text{ft}^3}{10^6\ \text{ft}^3}(\text{ppmvd})\right)\left(\frac{234{,}700\ \text{dscf}}{\text{min}}\right)\left(\frac{2{,}116.8\ \text{lb}}{\text{ft}^2}\right)\left(\frac{\text{lb}-\text{mole}-\text{R}}{1{,}545.6\ \text{ft}-\text{lb}_f}\right)\left(\frac{1}{528\ \text{R}}\right)\left(\frac{64\ \text{lb}}{\text{lb}-\text{mole}}\right)\left(\frac{60\ \text{min}}{\text{hr}}\right)=24.8\frac{\text{lb}}{\text{hr}}$$

No. 4 Smelt Dissolving Tanks- Emissions Unit ID # 019 - Rated capacity of 210,000 lb BLS/hr (24-hr average).

2004: 525,988 tons air-dried unbleached pulp or 744,438 tons BLS
Hours of operation: 8,082

2005: 534,339 tons air-dried unbleached pulp or 766,071 tons BLS
Hours of operation: 8,283

Unit has a wet scrubber with rated efficiency of 95-99.9%

Particulate Matter Emissions:

2004:

$$\mathrm{PM(hourly)} = 10.2\frac{\mathrm{lb}}{\mathrm{hr}} \text{ - Stack Test Data 8/27/2004}$$

$$\mathrm{PM(annual)} = \left(10.2\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}082\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 41.2\,\mathrm{TPY}$$

2005:

$$\mathrm{PM(hourly)} = 6.9\frac{\mathrm{lb}}{\mathrm{hr}} \text{ - Stack Test Data 9/9/2005}$$

$$\mathrm{PM(annual)} = \left(6.9\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}283\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 28.6\,\mathrm{TPY}$$

Average:

$$\mathrm{PM(hourly)} = 8.6\,\frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{PM(annual)} = 34.9\ \mathrm{TPY}$$

Particulate Matter (PM_{10}) Emissions: AP-42, Table 10.2-7 (9/90), indicates that PM_{10} emissions from smelt dissolving tanks with venturi scrubbers are equivalent to 90% of PM emissions.

2004:

$$\mathrm{PM}_{10}\mathrm{(hourly)} = (0.90)\left(10.2\frac{\mathrm{lb}}{\mathrm{hr}}\right) = 9.2\frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{PM}_{10}\mathrm{(annual)} = (0.90)(41.2\,\mathrm{TPY}) = 37.1\,\mathrm{TPY}$$

2005:

$$\mathrm{PM}_{10}\mathrm{(hourly)} = (0.90)\left(6.9\frac{\mathrm{lb}}{\mathrm{hr}}\right) = 6.2\frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{PM}_{10}\mathrm{(annual)} = (0.90)(28.6\,\mathrm{TPY}) = 25.7\,\mathrm{TPY}$$

Average:

$$\mathrm{PM}_{10}\mathrm{(hourly)} = 7.7\,\frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{PM}_{10}\mathrm{(annual)} = 31.4\ \mathrm{TPY}$$

Sulfur Dioxide Emissions: Emission factor - 0.073 lb/ton BLS (highest reported value for smelt dissolving tanks with scrubbers); NCASI TB #884, Table 4.15, August 2004.

2004:

$$SO_2\,(\text{hourly}) = 0.073\frac{\text{lb}}{\text{ton}}\left(\frac{744{,}438\,\text{ton}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}082\,\text{hr}}\right) = 6.7\frac{\text{lb}}{\text{hr}}$$

$$SO_2\,(\text{annual}) = \left(6.7\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}082\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 27.2\,\text{TPY}$$

2005:

$$SO_2\,(\text{hourly}) = 0.073\frac{\text{lb}}{\text{ton}}\left(\frac{766{,}071\,\text{ton}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}282.5\,\text{hr}}\right) = 6.8\frac{\text{lb}}{\text{hr}}$$

$$SO_2\,(\text{annual}) = \left(6.8\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}283\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 28.2\,\text{TPY}$$

Average:

$$SO_2\,(\text{hourly}) = 6.8\,\frac{\text{lb}}{\text{hr}}$$

$$SO_2\,(\text{annual}) = 27.7\ \text{TPY}$$

Nitrogen Oxides Emissions: Emission factor - 0.151 lb/ton BLS (highest reported value for smelt dissolving tanks with scrubbers); NCASI TB #884, Table 4.15, August 2004.

2004:

$$NO_x\,(\text{hourly}) = 0.151\frac{\text{lb}}{\text{ton}}\left(\frac{744{,}438\,\text{ton}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}082\,\text{hr}}\right) = 13.9\frac{\text{lb}}{\text{hr}}$$

$$NO_x\,(\text{annual}) = \left(13.9\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}082\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 56.2\,\text{TPY}$$

2005:

$$NO_x\,(\text{hourly}) = 0.151\frac{\text{lb}}{\text{ton}}\left(\frac{766{,}071\,\text{ton}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}282.5\,\text{hr}}\right) = 14.0\frac{\text{lb}}{\text{hr}}$$

$$NO_x\,(\text{annual}) = \left(14.0\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}283\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 58.0\,\text{TPY}$$

Average:

$$NO_x\,(\text{hourly}) = 14.0\,\frac{\text{lb}}{\text{hr}}$$

$$NO_x\,(\text{annual}) = 57.1\ \text{TPY}$$

Volatile Organic Compound Emissions: Emission factor - 0.25 lb/ton BLS (highest reported value for smelt dissolving tanks with scrubbers); NCASI TB #884, Table 4.15, August 2004.

2004:

$$\text{VOC(hourly)} = 0.25\frac{\text{lb}}{\text{ton}}\left(\frac{744{,}438\,\text{ton}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}082\,\text{hr}}\right) = 23.0\frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = \left(23.0\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}082\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 93.1\,\text{TPY}$$

2005:

$$\text{VOC(hourly)} = 0.25\frac{\text{lb}}{\text{ton}}\left(\frac{766{,}071\,\text{ton}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}282.5\,\text{hr}}\right) = 23.1\frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = \left(23.1\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}283\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 95.7\,\text{TPY}$$

Average:

$$\text{VOC(hourly)} = 23.1\,\frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = 94.4\ \text{TPY}$$

Carbon Monoxide Emissions: Emission factor - 0.025 lb/ton BLS (highest reported value for smelt dissolving tanks with scrubbers); NCASI TB #884, Table 4.15, August 2004.

2004:

$$\text{CO(hourly)} = 0.025\frac{\text{lb}}{\text{ton}}\left(\frac{744{,}438\,\text{ton}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}082\,\text{hr}}\right) = 2.3\frac{\text{lb}}{\text{hr}}$$

$$\text{CO(annual)} = \left(2.3\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}082\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 9.3\,\text{TPY}$$

2005:

$$\text{CO(hourly)} = 0.025\frac{\text{lb}}{\text{ton}}\left(\frac{766{,}071\,\text{ton}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}282.5\,\text{hr}}\right) = 2.3\frac{\text{lb}}{\text{hr}}$$

$$\text{CO(annual)} = \left(2.3\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}283\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 9.5\,\text{TPY}$$

Average:

$$\text{CO(hourly)} = 2.3\,\frac{\text{lb}}{\text{hr}}$$

$$\text{CO(annual)} = 9.4\ \text{TPY}$$

Total Reduced Sulfur Emissions:

2004:

$$\text{TRS(hourly)} = 1.5\frac{\text{lb}}{\text{hr}}\ \text{- Stack Test Data 3/5/2004}$$

$$\text{TRS(annual)} = \left(1.5\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}082\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 6.1\,\text{TPY}$$

2005:

$$\text{TRS(hourly)} = 1.0\frac{\text{lb}}{\text{hr}}$$ - Stack Test Data 9/9/2005

$$\text{TRS(annual)} = \left(1.0\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}283\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 4.1\,\text{TPY}$$

Average:

$$\text{TRS(hourly)} = 1.3\,\frac{\text{lb}}{\text{hr}}$$

$$\text{TRS(annual)} = 5.1\ \text{TPY}$$

Lead Emissions: Emission factor - 28 lb/MM ton BLS (mean value for smelt dissolving tanks with scrubbers); NCASI TB #701, Table 15B, October 1995.

2004:

$$\text{Pb(hourly)} = 28\frac{\text{lb}}{\text{MMton}}\left(\frac{744{,}438\,\text{ton}}{\text{yr}}\right)\left(\frac{\text{MMton}}{10^6\,\text{ton}}\right)\left(\frac{\text{yr}}{8{,}082\,\text{hr}}\right) = 2.6\text{x}10^{-3}\,\frac{\text{lb}}{\text{hr}}$$

$$\text{Pb(annual)} = \left(2.6\text{x}10^{-3}\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}082\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.01\,\text{TPY}$$

2005:

$$\text{Pb(hourly)} = 28\frac{\text{lb}}{\text{MMton}}\left(\frac{766{,}071\,\text{ton}}{\text{yr}}\right)\left(\frac{\text{MMton}}{10^6\,\text{ton}}\right)\left(\frac{\text{yr}}{8{,}282.5\,\text{hr}}\right) = 2.6\text{x}10^{-3}\,\frac{\text{lb}}{\text{hr}}$$

$$\text{Pb(annual)} = \left(2.6\text{x}10^{-3}\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}283\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.01\,\text{TPY}$$

Average:

$$\text{Pb(hourly)} = 2.6\text{x}10^{-3}\,\frac{\text{lb}}{\text{hr}}$$

$$\text{Pb(annual)} = 0.01\ \text{TPY}$$

Mercury Emissions: Emission factor - NCASI TB 701, Table 15B, October 1995 = $1.8\text{x}10^{-7}$ lb/ton BLS (median value).

2004:

$$\text{Hg(hourly)} = 1.8\text{x}10^{-7}\,\frac{\text{lb}}{\text{ton}}\left(\frac{744{,}438\,\text{ton}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}082\,\text{hr}}\right) = 1.7\text{x}10^{-5}\,\frac{\text{lb}}{\text{hr}}$$

$$\text{Hg(annual)} = \left(1.66\text{x}10^{-5}\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}082\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 6.7\text{x}10^{-5}\,\text{TPY}$$

2005:

$$\mathrm{Hg(hourly)} = 1.8\mathrm{x}10^{-7}\ \frac{\mathrm{lb}}{\mathrm{ton}}\left(\frac{766{,}071\,\mathrm{ton}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}282.5\,\mathrm{hr}}\right) = 1.7\mathrm{x}10^{-5}\ \frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{Hg(annual)} = \left(1.66\mathrm{x}10^{-5}\ \frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}283\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 6.9\mathrm{x}10^{-5}\ \mathrm{TPY}$$

Average:

$$\mathrm{Hg(hourly)} = 1.7\mathrm{x}10^{-5}\ \frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{Hg(annual)} = 6.8\mathrm{x}10^{-5}\ \mathrm{TPY}$$

Highest Daily PM_{10}, SO_2, NO_x, CO, and TRS Emission Rates – Used for Modeling Purposes

Highest daily emission rates:

lb/hr PM_{10} = 9.2 lb/hr (2004)
lb/hr SO_2 = 6.8 lb/hr (2005)
lb/hr NO_x = 14.0 lb/hr (2005)
lb/hr CO = 2.3 lb/hr (2004, 2005)
lb/hr TRS = 1.5 lb/hr (2004)

Black Liquor, Green Liquor Cycle-Emissions Unit ID # 042 - This area includes a number of miscellaneous fugitive and point emission sources as listed below:

Digester Area Black Liquor Storage Tanks:

Insignificant emission sources include the two, 65% Black Liquor day tanks, the 300,000 gallon Black Liquor tank, the 50% Black Liquor tank, the unfiltered strong Black Liquor Tank, the filtered Black Liquor tank, the million gallon weak Black Liquor tank, the 157,000 gallon weak liquor tank, the Strong Black Liquor Charge Tank, and the Tissue Black Liquor Charge Tank. The only information available for these emission sources is from NCASI TB # 677 (9/1994), Table V.A.1. Emissions data are provided only in the units of pounds per hour and not an emission factor. Therefore, it is not possible to estimate the increase in VOC emissions attributable to this project for these emission sources.

North & South Precipitator Tanks:

Volatile Organic Compound Emissions: Emission factor – NCASI TB 884, Table 4.17 = 0.003 lb/ton BLS (mean value).

2004:

$$\mathrm{VOC(hourly)} = \left(0.003\frac{\mathrm{lb\,VOC}}{\mathrm{ton\,BLS}}\right)\left(\frac{744{,}438\,\mathrm{ton\,BLS}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}760\,\mathrm{hr}}\right) = 0.25\ \mathrm{lb/hr}$$

$$\mathrm{VOC(annual)} = \left(0.25\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 1.1\,\mathrm{TPY}$$

2005:

$$\mathrm{VOC(hourly)} = \left(0.003\frac{\mathrm{lb\,VOC}}{\mathrm{ton\,BLS}}\right)\left(\frac{766{,}071\,\mathrm{ton\,BLS}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}760\,\mathrm{hr}}\right) = 0.26\ \mathrm{lb/hr}$$

$$\mathrm{VOC(annual)} = \left(0.26\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 1.1\,\mathrm{TPY}$$

Average:

$$\mathrm{VOC(hourly)} = 0.26\ \frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{VOC(annual)} = 1.1\ \mathrm{TPY}$$

Total Reduced Sulfur Emissions: Emission factors – NCASI Technical Bulletin 858, Table A-24 (mean value).

Dimethyl disulfide – 1.2×10^{-3} lb/ton BLS
Dimethyl sulfide – 2.6×10^{-3} lb/ton BLS
Methyl mercaptan – 9.8×10^{-5} lb/ton BLS

Total TRS Compounds = 0.004 lb/ton BLS

2004:

$$\mathrm{TRS(hourly)} = \left(0.004\frac{\mathrm{lb\,TRS}}{\mathrm{ton\,BLS}}\right)\left(\frac{744{,}438\,\mathrm{ton\,BLS}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}760\,\mathrm{hr}}\right) = 0.34\ \mathrm{lb/hr}$$

$$\text{TRS(annual)} = \left(0.34\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 1.5\,\text{TPY}$$

2005:

$$\text{TRS(hourly)} = \left(0.004\frac{\text{lb TRS}}{\text{ton BLS}}\right)\left(\frac{766{,}071\,\text{ton BLS}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 0.35\ \text{lb/hr}$$

$$\text{TRS(annual)} = \left(0.35\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 1.5\,\text{TPY}$$

Average:

$$\text{TRS(hourly)} = 0.35\ \frac{\text{lb}}{\text{hr}}$$

$$\text{TRS(annual)} = 1.5\ \text{TPY}$$

Salt Cake Mix Tank:

Volatile Organic Compound Emissions: Emission factor – NCASI TB 884, Table 4.17 = 0.003 lb/ton BLS (mean value).

2004:

$$\text{VOC(hourly)} = \left(0.003\frac{\text{lb VOC}}{\text{ton BLS}}\right)\left(\frac{744{,}438\,\text{ton BLS}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 0.25\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(0.25\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 1.1\,\text{TPY}$$

2005:

$$\text{VOC(hourly)} = \left(0.003\frac{\text{lb VOC}}{\text{ton BLS}}\right)\left(\frac{766{,}071\,\text{ton BLS}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 0.26\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(0.26\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 1.1\,\text{TPY}$$

Average:

$$\text{VOC(hourly)} = 0.26\ \frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = 1.1\ \text{TPY}$$

Total Reduced Sulfur Emissions: Emission factors – NCASI Technical Bulletin 858, Table A-24 (mean value).

Dimethyl disulfide – $1.2\text{x}10^{-3}$ lb/ton BLS
Dimethyl sulfide – $2.6\text{x}10^{-3}$ lb/ton BLS
Methyl mercaptan – $9.8\text{x}10^{-5}$ lb/ton BLS

Total TRS Compounds = 0.004 lb/ton BLS

2004:

$$\text{TRS(hourly)} = \left(0.004\frac{\text{lb TRS}}{\text{ton BLS}}\right)\left(\frac{744{,}438\text{ ton BLS}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 0.34\text{ lb/hr}$$

$$\text{TRS(annual)} = \left(0.34\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 1.5\text{ TPY}$$

2005:

$$\text{TRS(hourly)} = \left(0.004\frac{\text{lb TRS}}{\text{ton BLS}}\right)\left(\frac{766{,}071\text{ ton BLS}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 0.35\text{ lb/hr}$$

$$\text{TRS(annual)} = \left(0.35\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 1.5\text{ TPY}$$

Average:

$$\text{TRS(hourly)} = 0.35\ \frac{\text{lb}}{\text{hr}}$$

$$\text{TRS(annual)} = 1.5\text{ TPY}$$

<u>Green Liquor Clarifier:</u>

Volatile Organic Compound Emissions: Emission factor – NCASI TB 884, Table 4.14 = 0.066 lb/ton CaO (mean value).

2004:

$$\text{VOC(hourly)} = \left(0.066\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{111{,}731\text{ ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 0.84\text{ lb/hr}$$

$$\text{VOC(annual)} = \left(0.84\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 3.7\text{ TPY}$$

2005:

$$\text{VOC(hourly)} = \left(0.066\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{113{,}043\text{ ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 0.85\text{ lb/hr}$$

$$\text{VOC(annual)} = \left(0.85\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 3.7\text{ TPY}$$

Average:

$$\text{VOC(hourly)} = 0.85\ \frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = 3.7\text{ TPY}$$

Total Reduced Sulfur Emissions: Emission factors – NCASI Technical Bulletin 858, Table A-17 (mean value).

Dimethyl disulfide – $2\text{x}10^{-4}$ lb/ton CaO
Dimethyl sulfide – Not Detected
Methyl mercaptan – $4.2\text{x}10^{-4}$ lb/ton CaO

Total TRS Compounds = $6.2\text{x}10^{-4}$ lb/ton CaO

2004:

$$\text{TRS(hourly)} = \left(6.2\text{x}10^{-4}\,\frac{\text{lb TRS}}{\text{ton CaO}}\right)\left(\frac{111{,}731\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 7.9\text{x}10^{-3}\ \text{lb/hr}$$

$$\text{TRS(annual)} = \left(7.9\text{x}10^{-3}\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 3.5\text{x}10^{-2}\ \text{TPY}$$

2005:

$$\text{TRS(hourly)} = \left(6.2\text{x}10^{-4}\,\frac{\text{lb TRS}}{\text{ton CaO}}\right)\left(\frac{113{,}043\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 8.0\text{x}10^{-3}\ \text{lb/hr}$$

$$\text{TRS(annual)} = \left(8.0\text{x}10^{-3}\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 3.5\text{x}10^{-2}\ \text{TPY}$$

Average:

$$\text{TRS(hourly)} = 8.0\text{x}10^{-3}\ \frac{\text{lb}}{\text{hr}}$$

$$\text{TRS(annual)} = 3.5\text{x}10^{-2}\ \text{TPY}$$

<u>Green Liquor Tanks (North, South, and 280,000 gallon units):</u>

Volatile Organic Compound Emissions: Emission factor – NCASI TB 884, Table 4.14 = 0.066 lb/ton CaO (mean value).

2004:

$$\text{VOC(hourly)} = \left(0.066\,\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{111{,}731\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 0.84\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(0.84\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 3.7\,\text{TPY}$$

2005:

$$\text{VOC(hourly)} = \left(0.066\,\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{113{,}731\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 0.86\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(0.86\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 3.8\,\text{TPY}$$

Average:

$$\text{VOC(hourly)} = 0.85\ \frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = 3.8\ \text{TPY}$$

Total Reduced Sulfur Emissions: Emission factors – NCASI Technical Bulletin 858, Table A-17 (mean value).

Dimethyl disulfide – $3.1\text{x}10^{-5}$ lb/ton CaO
Dimethyl sulfide – $4.8\text{x}10^{-5}$ lb/ton CaO
Methyl mercaptan – $2.1\text{x}10^{-6}$ lb/ton CaO

Total TRS Compounds = $8.1\text{x}10^{-5}$ lb/ton CaO

2004:

$$\text{TRS(hourly)} = \left(8.1\text{x}10^{-5}\ \frac{\text{lb TRS}}{\text{ton CaO}}\right)\left(\frac{111{,}731\ \text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\ \text{hr}}\right) = 1.0\text{x}10^{-3}\ \text{lb/hr}$$

$$\text{TRS(annual)} = \left(1.0\text{x}10^{-3}\ \frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 4.5\text{x}10^{-3}\ \text{TPY}$$

2005:

$$\text{TRS(hourly)} = \left(8.1\text{x}10^{-5}\ \frac{\text{lb TRS}}{\text{ton CaO}}\right)\left(\frac{113{,}043\ \text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\ \text{hr}}\right) = 1.0\text{x}10^{-3}\ \text{lb/hr}$$

$$\text{TRS(annual)} = \left(1.0\text{x}10^{-3}\ \frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 4.4\text{x}10^{-3}\ \text{TPY}$$

Average:

$$\text{TRS(hourly)} = 1.0\text{x}10^{-3}\ \frac{\text{lb}}{\text{hr}}$$

$$\text{TRS(annual)} = 4.5\text{x}10^{-3}\ \text{TPY}$$

Highest Daily TRS Emission Rates – Used for Modeling Purposes

Highest daily emission rate:

North and South Precipitator Tanks: TRS = 0.4 lb/hr (2005)
Salt Cake Mix Tank: TRS = 0.4 lb/hr (2005)
Green Liquor Clarifier: TRS = 0.008 lb/hr (2005)
Green Liquor Tanks: TRS = 0.001 lb/hr (2004, 2005)

Total TRS = 0.8 lb/hr

Recausticizing

 # 4 Lime Kiln- Emissions Unit ID # 017 - The permitted input capacity of this unit is 82,986 lb/hr (of $CaCO_3$ & inerts)(24-hr block average). This equates to 19.44 tons/hr CaO produced. This unit has a venturi scrubber to control particulate matter emissions. This unit fires No. 6 fuel oil with a maximum sulfur content of 2.35% (by weight) to support combustion in the kiln.

2004: 525,988 tons air-dried unbleached pulp
Hours of operation: 7,688
6,335 M gallons No. 6 fuel oil @ 2.14% sulfur
111,731 tons CaO processed

2005: 534,339 tons air-dried unbleached pulp
Hours of operation: 8,198
6,182.5 M gallons No. 6 fuel oil @ 2.18% sulfur
113,043 tons CaO processed

Particulate Matter Emissions:

2004:

$$\text{PM(hourly)} = 7.9\frac{\text{lb}}{\text{hr}}$$ - Stack Test Data 2004 – Average of two stack tests – 4.2 lb/hr (3/3-4/2004) and 11.5 lb/hr (8/26/2004).

$$\text{PM(annual)} = \left(7.9\frac{\text{lb}}{\text{hr}}\right)\left(\frac{7{,}688\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 30.4\,\text{TPY}$$

2005:

$$\text{PM(hourly)} = 17.6\frac{\text{lb}}{\text{hr}}$$ - Stack Test Data 9/8/2005

$$\text{PM(annual)} = \left(17.6\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}198\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 72.1\,\text{TPY}$$

Average:

$$\text{PM(hourly)} = 12.8\,\frac{\text{lb}}{\text{hr}}$$

$$\text{PM(annual)} = 51.3\ \text{TPY}$$

Particulate Matter (PM_{10}) Emissions: PM_{10} assumed to be 98.3% PM, based on AP-42 Table 10.2-4 (9/90-reformatted 1/95) for a lime kiln with a venturi scrubber for control.

2004:

$$\text{PM}_{10}\text{(hourly)} = \left(7.9\frac{\text{lb}}{\text{hr}}\right)\text{x}0.983 = 7.8\frac{\text{lb}}{\text{hr}}$$

$$\text{PM}_{10}\text{(annual)} = (30.4\,\text{TPY})\text{x}0.983 = 29.9\,\text{TPY}$$

2005:

$$\text{PM}_{10}\text{(hourly)} = \left(17.6\frac{\text{lb}}{\text{hr}}\right)\text{x}0.983 = 17.3\frac{\text{lb}}{\text{hr}}$$

$$\text{PM}_{10}\text{(annual)} = (72.1\,\text{TPY})\text{x}0.983 = 70.9\,\text{TPY}$$

Average:

$$\text{PM}_{10}\,(\text{hourly}) = 12.6\,\frac{\text{lb}}{\text{hr}}$$

$$\text{PM}_{10}\,(\text{annual}) = 50.4\ \text{TPY}$$

Sulfur Dioxide Emissions:

2004:

$\text{SO}_2\,(\text{hourly}) = 0.01\,\frac{\text{lb}}{\text{hr}}$ - Based on detection limit of stack test conducted on 2/26/2004. Emissions are expected to be less than the detection limit.

$$\text{SO}_2\,(\text{annual}) = \left(0.01\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{7{,}688\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.04\,\text{TPY}$$

2005:

$\text{SO}_2\,(\text{hourly}) = 0.01\,\frac{\text{lb}}{\text{hr}}$ - Based on detection limit of stack test conducted on 9/8/2005. Emissions are expected to be less than the detection limit.

$$\text{SO}_2\,(\text{annual}) = \left(0.01\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}198\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.04\,\text{TPY}$$

Average:

$$\text{SO}_2\,(\text{hourly}) = 0.01\ \frac{\text{lb}}{\text{hr}}$$

$$\text{SO}_2\,(\text{annual}) = 0.04\ \text{TPY}$$

Sulfuric Acid Mist Emissions: Assume 3.6% of sulfur dioxide is sulfates. AP-42 emission factors of 5.7S lb/10^3 gal for SO_3 and 157S lb/10^3 gal for SO_2 (Table 1.3-1 (9/98)). The ratio of SO_3 to SO_2 is 3.6%, and then SO_3 was converted to sulfuric acid mist (SAM) by multiplying by ratio of molecular weights (x 98/80).

2004:

$$\text{SAM(hourly)} = \left(\frac{3.6\%}{100\%}\right)\left(0.01\,\frac{\text{lb}}{\text{hr}}\right) = 0.00036\,\frac{\text{lb}\,\text{SO}_3}{\text{hr}}\left(\frac{98\,\text{lb}\,\text{SAM}}{\text{lb}-\text{mole}\,\text{SAM}}\right)\left(\frac{\text{lb}-\text{mole}\,\text{SAM}}{\text{lb}-\text{mole}\,\text{SO}_3}\right)\left(\frac{\text{lb}-\text{mole}\,\text{SO}_3}{80\,\text{lb}\,\text{SO}_3}\right)$$

$$= 0.00044\,\frac{\text{lb}}{\text{hr}}$$

$$\text{SAM(annual)} = \left(0.00044\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{7{,}688\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.0017\,\text{TPY}$$

2005:

$$\text{SAM(hourly)} = \left(\frac{3.6\%}{100\%}\right)\left(0.01\,\frac{\text{lb}}{\text{hr}}\right) = 0.00036\,\frac{\text{lb}\,\text{SO}_3}{\text{hr}}\left(\frac{98\,\text{lb}\,\text{SAM}}{\text{lb}-\text{mole}\,\text{SAM}}\right)\left(\frac{\text{lb}-\text{mole}\,\text{SAM}}{\text{lb}-\text{mole}\,\text{SO}_3}\right)\left(\frac{\text{lb}-\text{mole}\,\text{SO}_3}{80\,\text{lb}\,\text{SO}_3}\right)$$

$$= 0.00044\,\frac{\text{lb}}{\text{hr}}$$

$$\mathrm{SAM(annual)} = \left(0.00044\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}198\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 0.0018\,\mathrm{TPY}$$

Average:

$$\mathrm{SAM(hourly)} = 0.00044\,\frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{SAM(annual)} = 0.0018\ \mathrm{TPY}$$

Total Reduced Sulfur Emissions:

2004:

$$\mathrm{TRS(hourly)} = 0.60\frac{\mathrm{lb}}{\mathrm{hr}}\ \text{- Stack Test Data 3/3/2004}$$

$$\mathrm{TRS(annual)} = \left(0.60\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{7{,}688\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 2.3\,\mathrm{TPY}$$

2005:

$$\mathrm{TRS(hourly)} = 0.69\frac{\mathrm{lb}}{\mathrm{hr}}\ \text{- Stack Test Data 9/8/2005}$$

$$\mathrm{TRS(annual)} = \left(0.69\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}198\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 2.8\,\mathrm{TPY}$$

Average:

$$\mathrm{TRS(hourly)} = 0.65\,\frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{TRS(annual)} = 2.6\ \mathrm{TPY}$$

Nitrogen Oxides Emissions:

2004:

$$\mathrm{NO_x\,(hourly)} = 33.7\frac{\mathrm{lb}}{\mathrm{hr}}\ \text{- Stack Test Data 2/26/2004}$$

$$\mathrm{NO_x\,(annual)} = \left(33.7\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{7{,}688\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 129.5\,\mathrm{TPY}$$

2005:

$$\mathrm{NO_x\,(hourly)} = 17.9\frac{\mathrm{lb}}{\mathrm{hr}}\ \text{- Stack Test Data 9/8/2005}$$

$$\mathrm{NO_x\,(annual)} = \left(17.9\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}198\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 73.3\,\mathrm{TPY}$$

Average:

$$\mathrm{NO_x\,(hourly)} = 25.8\,\frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{NO_x\,(annual)} = 101.4\ \mathrm{TPY}$$

Carbon Monoxide Emissions:

2004:

$$\text{CO(hourly)} = 1.4\frac{\text{lb}}{\text{hr}}$$ - Stack Test Data 2/26/2004

$$\text{CO(annual)} = \left(1.4\frac{\text{lb}}{\text{hr}}\right)\left(\frac{7{,}688\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 5.4\,\text{TPY}$$

2005:

$$\text{CO(hourly)} = 2.0\frac{\text{lb}}{\text{hr}}$$ - Stack Test Data 9/8/2005

$$\text{CO(annual)} = \left(2.0\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}198\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 8.2\,\text{TPY}$$

Average:

$$\text{CO(hourly)} = 1.7\,\frac{\text{lb}}{\text{hr}}$$

$$\text{CO(annual)} = 6.8\ \text{TPY}$$

Volatile Organic Compound Emissions:

2004:

$$\text{VOC(hourly)} = 0.60\frac{\text{lb}}{\text{hr}}$$ - Stack Test Data 2/26/2004

$$\text{VOC(annual)} = \left(0.60\frac{\text{lb}}{\text{hr}}\right)\left(\frac{7{,}688\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 2.3\,\text{TPY}$$

2005:

$$\text{VOC(hourly)} = 0.63\frac{\text{lb}}{\text{hr}}$$ - Stack Test Data 9/8/2005

$$\text{VOC(annual)} = \left(0.63\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}198\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 2.6\,\text{TPY}$$

Average:

$$\text{VOC(hourly)} = 0.62\frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = 2.5\,\text{TPY}$$

Lead Emissions: Emission factor = 2.9E-03 lb/ton CaO NCASI, TB # 858, Table 16C, February 2003, using the median of all oil-fired kilns.

2004:

$$\text{Pb(hourly)} = \left(2.9\text{x}10^{-3}\,\frac{\text{lb CaO}}{\text{ton}}\right)\left(\frac{111{,}731\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{7{,}688\,\text{hr}}\right) = 0.04\frac{\text{lb}}{\text{hr}}$$

$$\text{Pb(annual)} = \left(0.04\frac{\text{lb}}{\text{hr}}\right)\left(\frac{7{,}688\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.16\,\text{TPY}$$

2005:

$$\text{Pb(hourly)} = \left(2.9\text{x}10^{-3}\,\frac{\text{lb CaO}}{\text{ton}}\right)\left(\frac{113{,}043\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}198\,\text{hr}}\right) = 0.04\frac{\text{lb}}{\text{hr}}$$

$$\text{Pb(annual)} = \left(0.04\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}198\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.16\,\text{TPY}$$

Average:

$$\text{Pb(hourly)} = 0.04\,\frac{\text{lb}}{\text{hr}}$$

$$\text{Pb(annual)} = 0.16\ \text{TPY}$$

Highest Daily PM_{10}, SO_2, SAM, NO_x, CO, and TRS Emission Rates – Used for Modeling Purposes

Highest daily emission rates based on stack test data:

lb/hr PM_{10} = 17.3 lb/hr (2005)
lb/hr SO_2 = 0.01 lb/hr (2004, 2005)
lb/hr SAM = 0.0004 lb/hr (2004, 2005)
lb/hr NO_x = 33.7 lb/hr (2004)
lb/hr CO = 2.0 lb/hr (2005)
lb/hr TRS = 0.7 lb/hr (2005)

Caustic Area- Emissions Unit ID # 042 - This area includes a number of miscellaneous fugitive and point emission urces as listed below:

Lime (White Liquor) Slakers (Nos. 1 & 2)

Particulate Matter Emissions: Emission factor – NCASI TB 884, Table 4.14; mean = 0.031 lb/ton CaO.

2004:

$$\mathrm{PM(hourly)} = \left(0.031\frac{\mathrm{lb\,PM}}{\mathrm{ton\,CaO}}\right)\left(\frac{111{,}731\,\mathrm{ton\,CaO}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}760\,\mathrm{hr}}\right) = 0.40\ \mathrm{lb/hr}$$

$$\mathrm{PM(annual)} = \left(0.40\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 1.7\,\mathrm{TPY}$$

2005:

$$\mathrm{PM(hourly)} = \left(0.031\frac{\mathrm{lb\,PM}}{\mathrm{ton\,CaO}}\right)\left(\frac{113{,}043\,\mathrm{ton\,CaO}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}760\,\mathrm{hr}}\right) = 0.40\,\mathrm{lb/hr}$$

$$\mathrm{PM(annual)} = \left(0.40\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 1.7\,\mathrm{TPY}$$

Average:

$$\mathrm{PM(hourly)} = 0.40\ \frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{PM(annual)} = 1.7\ \mathrm{TPY}$$

Particulate Matter (PM_{10}) Emissions: Assume PM_{10} is 100% PM.

2004:

$$\mathrm{PM_{10}(hourly)} = (1)\left(0.40\frac{\mathrm{lb}}{\mathrm{hr}}\right) = 0.40\ \mathrm{lb/hr}$$

$$\mathrm{PM_{10}(annual)} = (1)(1.7\,\mathrm{TPY}) = 1.7\,\mathrm{TPY}$$

2005:

$$\mathrm{PM_{10}(hourly)} = (1)\left(0.40\frac{\mathrm{lb}}{\mathrm{hr}}\right) = 0.40\ \mathrm{lb/hr}$$

$$\mathrm{PM_{10}(annual)} = (1)(1.7\,\mathrm{TPY}) = 1.7\,\mathrm{TPY}$$

Average:

$$\mathrm{PM_{10}(hourly)} = 0.40\ \frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{PM_{10}(annual)} = 1.7\ \mathrm{TPY}$$

Volatile Organic Compound Emissions: Emission factor – NCASI TB 676, Table VII.A.5, Mill M (only mill with separate slaker and causticizer exhausts); mean = 0.041 lb/ton CaO.

2004:

$$\text{VOC(hourly)} = \left(0.041\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{111{,}731\text{ ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 0.52\text{ lb/hr}$$

$$\text{VOC(annual)} = \left(0.52\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 2.3\text{ TPY}$$

2005:

$$\text{VOC(hourly)} = \left(0.041\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{113{,}043\text{ ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 0.53\text{ lb/hr}$$

$$\text{VOC(annual)} = \left(0.53\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 2.3\text{ TPY}$$

Average:

$$\text{VOC(hourly)} = 0.53\ \frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = 2.3\ \text{TPY}$$

Total Reduced Sulfur Emissions: Emission factor – NCASI TB 849, Table 24; mean = 0.045 lb/ton CaO.

2004:

$$\text{TRS(hourly)} = \left(0.045\frac{\text{lb TRS}}{\text{ton CaO}}\right)\left(\frac{111{,}731\text{ ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 0.60\text{ lb/hr}$$

$$\text{TRS(annual)} = \left(0.60\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 2.6\text{ TPY}$$

2005:

$$\text{TRS(hourly)} = \left(0.045\frac{\text{lb TRS}}{\text{ton CaO}}\right)\left(\frac{113{,}043\text{ ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 0.60\text{ lb/hr}$$

$$\text{TRS(annual)} = \left(0.60\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 2.6\text{ TPY}$$

Average:

$$\text{TRS(hourly)} = 0.60\ \frac{\text{lb}}{\text{hr}}$$

$$\text{TRS(annual)} = 2.6\ \text{TPY}$$

White Liquor Storage Tanks (5 units)

Volatile Organic Compound Emissions: Emission factor – NCASI TB 858, Table A-17 = 0.0056 lb/ton CaO (mean value).

2004:

$$\text{VOC(hourly)} = \left(0.0056\,\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{111{,}731\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 0.07\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(0.07\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.31\,\text{TPY}$$

2005:

$$\text{VOC(hourly)} = \left(0.0056\,\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{113{,}043\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 0.07\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(0.07\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.31\,\text{TPY}$$

Average:

$$\text{VOC(hourly)} = 0.07\ \frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = 0.31\ \text{TPY}$$

White Liquor Clarifiers (East and West Units)

Volatile Organic Compound Emissions: Emission factor – NCASI TB 858, Table A-17 = 0.0056 lb/ton CaO (mean value).

2004:

$$\text{VOC(hourly)} = \left(0.0056\,\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{111{,}731\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 0.07\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(0.07\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.31\,\text{TPY}$$

2005:

$$\text{VOC(hourly)} = \left(0.0056\,\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{113{,}043\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 0.07\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(0.07\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.31\,\text{TPY}$$

Average:

$$\text{VOC(hourly)} = 0.07\ \frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = 0.31\ \text{TPY}$$

Lime Mud Washer Tanks (4 units)

Volatile Organic Compound Emissions: Emission factor = 0.085 lb VOC/ton CaO processed NCASI TB # 676, Table VIII.A.1-DCA3 (mean value).

2004:

$$\text{VOC(hourly)} = \left(0.085\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{111{,}731\text{ ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 1.1\text{ lb/hr}$$

$$\text{VOC(annual)} = \left(1.1\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 4.8\text{ TPY}$$

2005:

$$\text{VOC(hourly)} = \left(0.085\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{113{,}043\text{ ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 1.1\text{ lb/hr}$$

$$\text{VOC(annual)} = \left(1.1\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 4.8\text{ TPY}$$

Average:

$$\text{VOC(hourly)} = 1.1\ \frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = 4.8\text{ TPY}$$

Total Reduced Sulfur Emissions: Emission factor from NCASI TB# 676, Table VIII.A.1-DCA3 with values less than the detection limit represented as zero (mean values).

Dimethyl sulfide – 1.2E-03 lb/ton CaO
Methyl mercaptan – 7.4E-04 lb/ton CaO

Total TRS Compounds = 1.9E-03 lb/ton CaO

2004:

$$\text{TRS(hourly)} = \left(1.9\text{x}10^{-3}\frac{\text{lb TRS}}{\text{ton CaO}}\right)\left(\frac{111{,}731\text{ ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 0.025\text{ lb/hr}$$

$$\text{TRS(annual)} = \left(0.025\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 0.11\text{ TPY}$$

2005:

$$\text{TRS(hourly)} = \left(1.9\text{x}10^{-3}\frac{\text{lb TRS}}{\text{ton CaO}}\right)\left(\frac{113{,}043\text{ ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 0.025\text{ lb/hr}$$

$$\text{TRS(annual)} = \left(0.025\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 0.11\text{ TPY}$$

Average:

$$\text{TRS(hourly)} = 0.025\ \frac{\text{lb}}{\text{hr}}$$

$$\text{TRS(annual)} = 0.11\text{ TPY}$$

Lime Mud Splitter Box Tank

Volatile Organic Compound Emissions: Emission factor = 0.085 lb VOC/ton CaO processed NCASI TB # 676, Table VIII.A.1-DCA3 (mean value).

2004:

$$\text{VOC(hourly)} = \left(0.085\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{111{,}731\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 1.1\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(1.1\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 4.8\,\text{TPY}$$

2005:

$$\text{VOC(hourly)} = \left(0.085\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{113{,}043\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 1.1\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(1.1\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 4.8\,\text{TPY}$$

Average:

$$\text{VOC(hourly)} = 1.1\ \frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = 4.8\ \text{TPY}$$

Total Reduced Sulfur Emissions: Emission factor from NCASI TB# 676, Table VIII.A.1-DCA3 with values less than the detection limit represented as zero (mean values).

Dimethyl sulfide – $1.2\text{x}10^{-3}$ lb/ton CaO
Methyl mercaptan – $7.4\text{x}10^{-4}$ lb/ton CaO

Total TRS Compounds = $1.9\text{x}10^{-3}$ lb/ton CaO

2004:

$$\text{TRS(hourly)} = \left(0.0019\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{111{,}731\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 0.024\ \text{lb/hr}$$

$$\text{TRS(annual)} = \left(0.024\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.11\,\text{TPY}$$

2005:

$$\text{TRS(hourly)} = \left(0.0019\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{113{,}043\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 0.025\ \text{lb/hr}$$

$$\text{TRS(annual)} = \left(0.025\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.11\,\text{TPY}$$

Average:

$$\text{TRS(hourly)} = 0.025\ \frac{\text{lb}}{\text{hr}}$$

$$\text{TRS(annual)} = 0.11\ \text{TPY}$$

Causticizer Tanks (Nos. 1A, 1B, 2,3)

Volatile Organic Compound Emissions: Emission factor – NCASI TB 676, Table VII.A.5, Mill M (only mill with separate slaker and causticizer exhausts); mean = 8.3E-04 lb/ton CaO.

2004:

$$\text{VOC(hourly)} = \left(0.00083\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{111{,}731\ \text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\ \text{hr}}\right) = 0.011\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(0.011\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 0.05\ \text{TPY}$$

2005:

$$\text{VOC(hourly)} = \left(0.00083\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{113{,}043\ \text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\ \text{hr}}\right) = 0.011\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(0.011\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 0.05\ \text{TPY}$$

Average:

$$\text{VOC(hourly)} = 0.011\ \frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = 0.05\ \text{TPY}$$

Total Reduced Sulfur Emissions: Emission factor – NCASI TB 849, Table 24; mean = 0.019 lb/ton CaO (as sulfur); factor as hydrogen sulfide = 0.019 x 34/32 = 0.020 lb/ton CaO.

2004:

$$\text{TRS(hourly)} = \left(0.020\frac{\text{lb TRS}}{\text{ton CaO}}\right)\left(\frac{111{,}731\ \text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\ \text{hr}}\right) = 0.26\ \text{lb/hr}$$

$$\text{TRS(annual)} = \left(0.26\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 1.13\ \text{TPY}$$

2005:

$$\text{TRS(hourly)} = \left(0.020\frac{\text{lb TRS}}{\text{ton CaO}}\right)\left(\frac{113{,}043\ \text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\ \text{hr}}\right) = 0.26\ \text{lb/hr}$$

$$\text{TRS(annual)} = \left(0.26\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 1.13\ \text{TPY}$$

Average:

$$\text{TRS(hourly)} = 0.26\ \frac{\text{lb}}{\text{hr}}$$

$$\text{TRS(annual)} = 1.13\ \text{TPY}$$

Highest Daily PM_{10} and TRS Emission Rates – Used for Modeling Purposes

Highest daily TRS emission rates:

Lime Slakers: TRS = 0.60 lb/hr (2004/2005)
Lime Mud Washer Tanks: TRS = 0.025 lb/hr (2004/2005)
Lime Mud Splitter Box Tank: TRS = 0.025 lb/hr
Causticizer Tanks: TRS = 0.26 lb/hr (2004/2005)

Total TRS = 0.91 lb/hr

Highest daily PM_{10} emission rates:

Lime Slakers: PM_{10} = 0.4 lb/hr (2004/2005)

Total PM_{10} = 0.4 lb/hr

APPENDIX D

POTENTIAL EMISSION RATE CALCULATIONS FOR PROJECT-AFFECTED SOURCES

APPENDIX D

POTENTIAL EMISSION RATE CALCULATIONS FOR PROJECT-AFFECTED SOURCES

Palatka, Florida Mill Emission Rate Calculations - Comments and Assumptions

The basis for pollutant potential emission estimates are taken from a number of sources. These include Title V Permit limits, general engineering knowledge and assumptions concerning process operations, emission factors published in US EPA Manual AP-42, various technical bulletins and other reports published by NCASI and EPA's FIRE data system. All potential emission calculations are based on the Mill operating 8,760 hours per year, unless specifically noted otherwise.

The pollutants considered for emission estimating purposes include: particulate matter (total particulate matter and PM_{10}), nitrogen oxides, sulfur dioxide, carbon monoxide, volatile organic compounds, lead, mercury, total reduced sulfur, and sulfuric acid mist.

There are a number of changes in Title V Permit limits that are addressed in the potential emission rate calculations below. A summary of the current Title V Permit limits (as of Title V Permit Revision No. 1070005-034-AV, dated December 20, 2005) and requested changes are listed below. The reasons for the changes are discussed in the detailed emission calculations following this table.

Chemical Recovery

No. 4 Recovery Boiler- Emissions Unit ID # 018 - Rated capacity of 210,000 lb/hr of BLS or 5.04 MM lb BLS/day. Maximum dry standard cubic feet per minute (dscfm) at 2.8% oxygen = 210,000 dscfm = 294,000 dscfm @ 8% oxygen. Maximum CaO = 38,889 lb/hr or 170,334 ton CaO/yr.

	Current Title V Limits 1070005-029-AV		**Proposed Title V Limits**	
Pollutant	**lb/hr**	**TPY**	**lb/hr**	**TPY**
PM	75.6	331.1	75.6	331.1
PM_{10}	-	-	56.7	248.3
VOC	31.5	138.0	21.0	92.0
SO_2	109.9	481.4	439.4 (3-hr) 292.8 (24-hr) 35.1 (annual)	153.9
NO_x	168.5	738.1	168.5	738.1
SAM	3.2	14.2	3.6	15.9
CO	1,025.4 (3-hr) 512.7 (24-hr)	2,245.6 (24-hr)	1,025.4 (3-hr) 512.7 (24-hr)	2,245.6 (24-hr)
TRS	10.9 (12-mo) 17.5 (12-hr)	47.7 (12-mo)	17.5 (12-hour) 7.8 (12-month)	34.2
Lead	-	-	0.0033	0.014
Be	6.4E-04	2.8E-03	6.4E-04	2.8E-03

Oxygen correction from 210,000 dscfm at 2.8% oxygen to 8% oxygen is shown in the calculations below.

$$\text{Correction Factor} = \text{Actual}\left[\frac{(21-2.8)}{(21-8.0)}\right] = \text{Actual}(1.4)$$

$$\text{Corrected Oxygen} = 210{,}000\,\text{dscfm}(1.4) = 294{,}000\,\text{dscfm at 8\% oxygen}$$

Particulate Matter Emissions - 75.6 lb/hr and 331.1 TPY - Current Title V Permit Limits (Section III Subsection E.4).

$$\text{PM (hourly)} = \left(\frac{0.03\ \text{grains}}{\text{dscf}}\right)\left(\frac{294{,}000\ \text{dscf}}{\text{min}}\right)\left(\frac{1\ \text{lb}}{7{,}000\ \text{grains}}\right)\left(\frac{60\ \text{min}}{\text{hr}}\right) = 75.6\,\frac{\text{lb}}{\text{hr}}$$

$$\text{PM(annual)} = \left(75.6\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 331.1\,\text{TPY}$$

Proposed PM_{10} limits of 56.7 lb/hr and 248.3 TPY based on PM_{10} as 75% of PM from AP-42, Table 10.2-3 (9/90).

$$\text{PM}_{10}\text{(hourly)} = 0.75\left(75.6\frac{\text{lb}}{\text{hr}}\right) = 56.7\frac{\text{lb}}{\text{hr}}$$

$$\text{PM}_{10}\text{(annual)} = \left(56.7\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 248.3\,\text{TPY}$$

Sulfur Dioxide Emissions - 109.9 lb/hr and 481.4 TPY - Current Title V Permit Limits (Section III Subsection E.7). Proposed SO_2 limits based on annual average = 12 ppmvd @ 8% oxygen; 24-hr average = 100 ppmvd @ 8% oxygen; 3-hr average = 150 ppmvd @ 8% oxygen.

3-hour average:

$$SO_2\,(\text{hourly}) =$$
$$\left(\frac{150\ \text{ft}^3}{10^6\ \text{ft}^3}(\text{ppmvd})\right)\left(\frac{294{,}000\ \text{dscf}}{\text{min}}\right)\left(\frac{2{,}116.8\ \text{lb}}{\text{ft}^2}\right)\left(\frac{\text{lb}-\text{mole}-\text{R}}{1{,}545.6\ \text{ft}-\text{lb}_f}\right)\left(\frac{1}{528\ \text{R}}\right)\left(\frac{64\ \text{lb}}{\text{lb}-\text{mole}}\right)\left(\frac{60\ \text{min}}{\text{hr}}\right) = 439.4\frac{\text{lb}}{\text{hr}}$$

24-hour average:

$$SO_2\,(\text{hourly}) =$$
$$\left(\frac{100\ \text{ft}^3}{10^6\ \text{ft}^3}(\text{ppmvd})\right)\left(\frac{294{,}000\ \text{dscf}}{\text{min}}\right)\left(\frac{2{,}116.8\ \text{lb}}{\text{ft}^2}\right)\left(\frac{\text{lb}-\text{mole}-\text{R}}{1{,}545.6\ \text{ft}-\text{lb}_f}\right)\left(\frac{1}{528\ \text{R}}\right)\left(\frac{64\ \text{lb}}{\text{lb}-\text{mole}}\right)\left(\frac{60\ \text{min}}{\text{hr}}\right) = 292.8\frac{\text{lb}}{\text{hr}}$$

Annual average:

$$SO_2\,(\text{hourly}) =$$
$$\left(\frac{12\ \text{ft}^3}{10^6\text{ft}^3}(\text{ppmvd})\right)\left(\frac{294{,}000\ \text{dscf}}{\text{min}}\right)\left(\frac{2{,}116.8\ \text{lb}}{\text{ft}^2}\right)\left(\frac{\text{lb}-\text{mole}-\text{R}}{1{,}545.6\ \text{ft}-\text{lb}_f}\right)\left(\frac{1}{528\ \text{R}}\right)\left(\frac{64\ \text{lb}}{\text{lb}-\text{mole}}\right)\left(\frac{60\ \text{min}}{\text{hr}}\right) = 35.14\frac{\text{lb}}{\text{hr}}$$

$$SO_2\,(\text{annual}) = \left(35.14\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 153.9\ \text{TPY}$$

Sulfuric Acid Mist Emissions - 3.2 lb/hr and 14.2 TPY - Current Title V Permit Limits (Section III Subsection E.11) based on a limit of 0.81 ppmvd. Proposed Title V Permit Limits of 3.6 lb/hr and 15.8 TPY based on concentration of 0.8 ppmvd, corrected to 8% oxygen.

1-hour average:

$$\text{SAM}\,(\text{hourly}) =$$
$$\left(\frac{0.8\ \text{ft}^3}{10^6\ \text{ft}^3}(\text{ppmvd})\right)\left(\frac{294{,}000\ \text{dscf}}{\text{min}}\right)\left(\frac{2{,}116.8\ \text{lb}}{\text{ft}^2}\right)\left(\frac{\text{lb}-\text{mole}-\text{R}}{1{,}545.6\ \text{ft}-\text{lb}_f}\right)\left(\frac{1}{528\ \text{R}}\right)\left(\frac{98\ \text{lb}}{\text{lb}-\text{mole}}\right)\left(\frac{60\ \text{min}}{\text{hr}}\right) = 3.6\frac{\text{lb}}{\text{hr}}$$

Annual average:

$$\text{SAM}(\text{annual}) = \left(3.6\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 15.9\text{TPY}$$

Nitrogen Oxide Emissions - 168.5 lb/hr and 738.1 TPY - Current Title V Permit Limits (Section III Subsection E.8).

$$\text{NOx}_x\,(\text{hourly}) =$$
$$\left(\frac{80\ \text{ft}^3}{10^6\ \text{ft}^3}(\text{ppmvd})\right)\left(\frac{294{,}000\ \text{dscf}}{\text{min}}\right)\left(\frac{2{,}116.8\ \text{lb}}{\text{ft}^2}\right)\left(\frac{\text{lb}-\text{mole}-\text{R}}{1{,}545.6\ \text{ft}-\text{lb}_f}\right)\left(\frac{1}{528\ \text{R}}\right)\left(\frac{46\ \text{lb}}{\text{lb}-\text{mole}}\right)\left(\frac{60\ \text{min}}{\text{hr}}\right) = 168.5\frac{\text{lb}}{\text{hr}}$$

$$\mathrm{NO_x\,(annual)} = \left(168.5\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 738.1\,\mathrm{TPY}$$

Carbon Monoxide Emissions - 1,025.4 lb/hr (3-hr block average), 512.7 lb/hr (24-hr block average), and 2,245.6 TPY - Current Title V Permit Limits (Section III Subsection E.9).

3-hour average:

$$\mathrm{CO\,(hourly)} =$$

$$\left(\frac{800\ \mathrm{ft^3}}{10^6\,\mathrm{ft^3}}(\mathrm{ppmvd})\right)\left(\frac{294{,}000\ \mathrm{dscf}}{\mathrm{min}}\right)\left(\frac{2{,}116.8\,\mathrm{lb}}{\mathrm{ft^2}}\right)\left(\frac{\mathrm{lb-mole-R}}{1{,}545.6\,\mathrm{ft-lb_f}}\right)\left(\frac{1}{528\ \mathrm{R}}\right)\left(\frac{28\ \mathrm{lb}}{\mathrm{lb-mole}}\right)\left(\frac{60\ \mathrm{min}}{\mathrm{hr}}\right) = 1{,}025.4\frac{\mathrm{lb}}{\mathrm{hr}}$$

24-hour and annual average:

$$\mathrm{CO\,(hourly)} =$$

$$\left(\frac{400\ \mathrm{ft^3}}{10^6\,\mathrm{ft^3}}(\mathrm{ppmvd})\right)\left(\frac{294{,}000\ \mathrm{dscf}}{\mathrm{min}}\right)\left(\frac{2{,}116.8\,\mathrm{lb}}{\mathrm{ft^2}}\right)\left(\frac{\mathrm{lb-mole-R}}{1{,}545.6\,\mathrm{ft-lb_f}}\right)\left(\frac{1}{528\ \mathrm{R}}\right)\left(\frac{28\ \mathrm{lb}}{\mathrm{lb-mole}}\right)\left(\frac{60\ \mathrm{min}}{\mathrm{hr}}\right) = 512.7\frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{CO(annual)} = \left(512.7\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 2{,}245.6\,\mathrm{TPY}$$

Volatile Organic Compound Emissions - 31.5 lb/hr and 138.0 TPY - Current Title V Permit Limits (Section III Subsection E.10). Proposed Title V Permit limits of 21.0 lb/hr and 92.0 TPY are based on limits agreed to between Mill and FL DEP.

$$\mathrm{VOC(hourly)} = \left(0.20\frac{\mathrm{lb}}{\mathrm{ton}}\right)\left(\frac{210{,}000\,\mathrm{lb\,BLS}}{\mathrm{hr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 21.0\frac{\mathrm{lb}}{\mathrm{hr}}$$

$$\mathrm{VOC(annual)} = \left(21.0\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 92.0\,\mathrm{TPY}$$

Total Reduced Sulfur Emissions – Current Title V Permit Limits:

7.0 ppmvd @ 8% O_2, 10.9 lb/hr and 47.7 TPY as H_2S (12-month rolling average)
11.2 ppmvd @ 8% O_2, 17.5 lb/hr as H_2S (12-hour block average)

Proposed limit is 5 ppmvd @ 8% O_2, 7.8 lb/hr and 34.2 TPY as H_2S (12-month rolling)

12-hour block average:

$$\mathrm{TRS\,(hourly)} =$$

$$\left(\frac{11.2\ \mathrm{ft^3}}{10^6\,\mathrm{ft^3}}(\mathrm{ppmvd})\right)\left(\frac{294{,}000\ \mathrm{dscf}}{\mathrm{min}}\right)\left(\frac{2{,}116.8\,\mathrm{lb}}{\mathrm{ft^2}}\right)\left(\frac{\mathrm{lb-mole-R}}{1{,}545.6\,\mathrm{ft-lb_f}}\right)\left(\frac{1}{528\ \mathrm{R}}\right)\left(\frac{34\ \mathrm{lb}}{\mathrm{lb-mole}}\right)\left(\frac{60\ \mathrm{min}}{\mathrm{hr}}\right) = 17.5\frac{\mathrm{lb}}{\mathrm{hr}}$$

Annual average:

TRS (hourly) =

$$\left(\frac{5\,\text{ft}^3}{10^6\,\text{ft}^3}(\text{ppmvd})\right)\left(\frac{294{,}000\ \text{dscf}}{\text{min}}\right)\left(\frac{2{,}116.8\,\text{lb}}{\text{ft}^2}\right)\left(\frac{\text{lb}-\text{mole}-\text{R}}{1{,}545.6\,\text{ft}-\text{lb}_f}\right)\left(\frac{1}{528\,\text{R}}\right)\left(\frac{34\,\text{lb}}{\text{lb}-\text{mole}}\right)\left(\frac{60\ \text{min}}{\text{hr}}\right)=7.8\frac{\text{lb}}{\text{hr}}$$

$$\text{TRS(annual)}=\left(7.8\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right)=34.2\,\text{TPY}$$

Lead Emissions – Proposed Title V permit limits of 0.0033 lb/hr and 0.014 TPY based on emission factor for BLS firing of 31.3 lb/MM ton BLS from NCASI TB # 701, Table 12 D (median value).

$$\text{Pb(hourly)}=\left(31.3\frac{\text{lb}}{\text{MMton}}\right)\left(\frac{\text{MMton}}{10^6\,\text{ton}}\right)\left(\frac{210{,}000\,\text{lb BLS}}{\text{hr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right)=0.0033\frac{\text{lb}}{\text{hr}}$$

$$\text{Pb(annual)}=\left(0.0033\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right)=0.014\,\text{TPY}$$

Beryllium Emissions - 0.5 lb/10^{12} Btu or $6.4\text{x}10^{-4}$ lb/hr and $2.8\text{x}10^{-3}$ TPY - Current Title V Permit Limits (Section III Subsection E.12).

$$\text{Be(hourly)}=\left(\frac{0.5\,\text{lb}}{10^{12}\,\text{Btu}}\right)\left(\frac{210{,}000\,\text{lb BLS}}{\text{hr}}\right)\left(\frac{6{,}084\,\text{Btu}}{\text{lb}}\right)=6.4\text{x}10^{-4}\frac{\text{lb}}{\text{hr}}$$

$$\text{Be(annual)}=\left(6.4\text{x}10^{-4}\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right)=2.8\text{x}10^{-3}\,\text{TPY}$$

Mercury Emissions: Emission factor of $1.8\text{x}10^{-7}$ lb/ton BLS from NCASI TB 858, Table 14B (median value).

$$\text{Hg(hourly)}=1.8\text{x}10^{-7}\frac{\text{lb}}{\text{ton}}\left(\frac{210{,}000\,\text{lb}}{\text{hr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right)=1.9\text{x}10^{-5}\frac{\text{lb}}{\text{hr}}$$

$$\text{Hg(annual)}=\left(1.9\text{x}10^{-5}\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right)=8.3\text{x}10^{-5}\,\text{TPY}$$

No. 4 Smelt Dissolving Tank - Emissions Unit ID # 019 - Rated capacity of 210,000 lb BLS/hr (24-hr average).

Particulate Matter Emissions: 0.12 lb/ton BLS (based on BACT limit established in 1991 PSD permit application) or 12.6 lb/hr and 55.2 TPY – Current Title V Permit Limits.

$$\text{PM(hourly)} = \left(0.12\frac{\text{lb}}{\text{ton BLS}}\right)\left(\frac{210{,}000\,\text{lb BLS}}{\text{hr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 12.6\frac{\text{lb}}{\text{hr}}$$

$$\text{PM(annual)} = \left(12.6\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 55.2\,\text{TPY}$$

Particulate Matter (PM_{10}) Emissions: AP-42, Table 10.2-7 (9/90), indicates that PM_{10} emissions from smelt dissolving tanks are equivalent to 90% of PM emissions.

$$\text{PM}_{10}\text{(hourly)} = (0.90)\left(12.6\frac{\text{lb}}{\text{hr}}\right) = 11.3\frac{\text{lb}}{\text{hr}}$$

$$\text{PM}_{10}\text{(annual)} = (0.90)(55.2\,\text{TPY}) = 49.7\,\text{TPY}$$

Sulfur Dioxide Emissions: Emission factor - 0.073 lb/ton BLS (highest reported value for smelt dissolving tanks with scrubbers); NCASI TB # 884, Table 4.15, August 2004.

$$\text{SO}_2\text{(hourly)} = \left(0.073\frac{\text{lb}}{\text{ton BLS}}\right)\left(\frac{210{,}000\,\text{lb BLS}}{\text{hr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 7.7\frac{\text{lb}}{\text{hr}}$$

$$\text{SO}_2\text{(annual)} = \left(7.7\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 33.7\,\text{TPY}$$

Nitrogen Oxides Emissions: Emission factor - 0.151 lb/ton BLS (highest reported value for smelt dissolving tanks with scrubbers); NCASI TB # 884, Table 4.15, August 2004.

$$\text{NO}_x\text{(hourly)} = \left(0.151\frac{\text{lb}}{\text{ton BLS}}\right)\left(\frac{210{,}000\,\text{lb BLS}}{\text{hr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 15.9\frac{\text{lb}}{\text{hr}}$$

$$\text{NO}_x\text{(annual)} = \left(15.9\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 69.6\,\text{TPY}$$

Volatile Organic Compound Emissions: Emission factor - 0.25 lb/ton BLS (highest reported value for smelt dissolving tanks with scrubbers); NCASI TB # 884, Table 4.15, August 2004.

$$\text{VOC(hourly)} = \left(0.25\frac{\text{lb}}{\text{ton BLS}}\right)\left(\frac{210{,}000\,\text{lb BLS}}{\text{hr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 26.25\frac{\text{lb}}{\text{hr}}$$

$$\text{VOC(annual)} = \left(26.25\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 115.0\,\text{TPY}$$

Carbon Monoxide Emissions: Emission factor - 0.025 lb/ton BLS (highest reported value for smelt dissolving tanks with scrubbers); NCASI TB # 884, Table 4.15, August 2004.

$$\text{CO(hourly)} = \left(0.025\frac{\text{lb}}{\text{ton BLS}}\right)\left(\frac{210{,}000\,\text{lb BLS}}{\text{hr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 2.6\frac{\text{lb}}{\text{hr}}$$

$$\text{CO(annual)} = \left(2.6\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 11.4\,\text{TPY}$$

Total Reduced Sulfur Emissions: Current Title V permit limit: 0.048 lb TRS/3,000 lb BLS as H_2S (FL DEP state rule 296.404(3)(d)(1)) or 3.4 lb/hr and 14.9 ton/yr.

$$\text{TRS(hourly)} = \left(\frac{0.048\,\text{lb TRS}}{3{,}000\,\text{lb BLS}}\right)\left(\frac{210{,}000\,\text{lb BLS}}{\text{hr}}\right) = 3.4\,\text{lb/hr}$$

$$\text{TRS(annual)} = \left(3.4\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 14.9\,\text{TPY}$$

Lead Emissions: Emission factor - 28 lb/MM ton BLS (mean value for smelt dissolving tanks with scrubbers); NCASI TB # 701, Table 15B, October 1995.

$$\text{Pb(hourly)} = \left(\frac{28\,\text{lb}}{\text{MMton BLS}}\right)\left(\frac{1.05\text{x}10^{-4}\,\text{MMton BLS}}{\text{hr}}\right) = 2.9\text{x}10^{-3}\ \text{lb/hr}$$

$$\text{Pb(annual)} = \left(2.9\text{x}10^{-3}\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.013\,\text{TPY}$$

Mercury Emissions: Emission factor – 1.8x10^{-7} lb/ton BLS (median value for smelt dissolving tanks with ND = 0); NCASI TB #701, Table 15B, October 1995.

$$\text{Hg(hourly)} = 1.8\text{x}10^{-7}\frac{\text{lb}}{\text{ton}}\left(\frac{210{,}000\,\text{lb}}{\text{hr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 1.9\text{x}10^{-5}\frac{\text{lb}}{\text{hr}}$$

$$\text{Hg(annual)} = \left(1.9\text{x}10^{-5}\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 8.3\text{x}10^{-5}\ \text{TPY}$$

Black Liquor, Green Liquor Cycle-Emissions Unit ID # 042-This area includes a number of miscellaneous fugitive and point emission sources as listed below:

Digester Area Black Liquor Storage Tanks:

Insignificant emission sources include the two, 65% Black Liquor day tanks, the 300,000 gallon Black Liquor tank, the 50% Black Liquor tank, the unfiltered strong Black Liquor Tank, the filtered Black Liquor tank, the million gallon weak Black Liquor tank, the 157,000 gallon weak liquor tank, the Strong Black Liquor Charge Tank, and the Tissue Black Liquor Charge Tank. The only information available for these emission sources is from NCASI TB # 677 (9/1994), Table V.A.1. Emissions data are provided only in the units of pounds per hour and not an emission factor. Therefore, it is not possible to estimate the increase in VOC emissions attributable to this project for these emission sources.

North & South Precipitator Tanks:

Volatile Organic Compound Emissions: Emission factor – NCASI TB 884, Table 4.17 = 0.003 lb/ton BLS (mean value).

$$\text{Potential ton BLS processed/yr} = \left(\frac{210{,}000\,\text{lb BLS}}{\text{hr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 105\,\frac{\text{ton BLS}}{\text{hr}}$$

$$\text{VOC(hourly)} = \left(0.003\,\frac{\text{lb TRS}}{\text{ton BLS}}\right)\left(\frac{105\,\text{ton BLS}}{\text{hr}}\right) = 0.315\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(0.315\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 1.4\,\text{TPY}$$

Total Reduced Sulfur Emissions: Emission factors – NCASI Technical Bulletin 858, Table A-24 (mean value).

Dimethyl disulfide – $1.2\text{x}10^{-3}$ lb/ton BLS
Dimethyl sulfide – $2.6\text{x}10^{-3}$ lb/ton BLS
Methyl mercaptan – $9.8\text{x}10^{-5}$ lb/ton BLS

Total TRS Compounds = 0.004 lb/ton BLS

$$\text{Potential ton BLS processed/yr} = \left(\frac{210{,}000\,\text{lb BLS}}{\text{hr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 105\,\frac{\text{ton BLS}}{\text{hr}}$$

$$\text{TRS(hourly)} = \left(0.004\,\frac{\text{lb TRS}}{\text{ton BLS}}\right)\left(\frac{105\,\text{ton BLS}}{\text{hr}}\right) = 0.42\ \text{lb/hr}$$

$$\text{TRS(annual)} = \left(0.42\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 1.84\,\text{TPY}$$

Salt Cake Mix Tank:

Volatile Organic Compound Emissions: Emission factor – NCASI TB 884, Table 4.17 = 0.003 lb/ton BLS (mean value).

$$\text{Potential ton BLS processed/yr} = \left(\frac{210{,}000\,\text{lb BLS}}{\text{hr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 105\,\frac{\text{ton BLS}}{\text{hr}}$$

$$\text{VOC(hourly)} = \left(0.003\,\frac{\text{lb TRS}}{\text{ton BLS}}\right)\left(\frac{105\,\text{ton BLS}}{\text{hr}}\right) = 0.315\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(0.315\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 1.4\,\text{TPY}$$

Total Reduced Sulfur Emissions: Emission factors – NCASI Technical Bulletin 858, Table A-24 (mean values).

Dimethyl disulfide – $1.2\text{x}10^{-3}$ lb/ton BLS
Dimethyl sulfide – $2.6\text{x}10^{-3}$ lb/ton BLS
Methyl mercaptan – $9.8\text{x}10^{-5}$ lb/ton BLS

Total TRS Compounds = 0.004 lb/ton BLS

$$\text{Potential ton BLS processed/yr} = \left(\frac{210{,}000\,\text{lb BLS}}{\text{hr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 105\,\frac{\text{ton BLS}}{\text{hr}}$$

$$\text{TRS(hourly)} = \left(0.004\,\frac{\text{lb TRS}}{\text{ton BLS}}\right)\left(\frac{105\,\text{ton BLS}}{\text{hr}}\right) = 0.42\ \text{lb/hr}$$

$$\text{TRS(annual)} = \left(0.42\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 1.84\,\text{TPY}$$

Green Liquor Clarifier:

Volatile Organic Compound Emissions: Emission factor – NCASI TB 884, Table 4.14 = 0.066 lb/ton CaO (mean value).

Potential quantity of CaO processed = 170,334 TPY or 19.44 ton/hr

$$\text{VOC(hourly)} = \left(0.066\,\frac{\text{lb}}{\text{ton CaO}}\right)\left(\frac{170{,}334\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 1.3\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(1.3\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 5.6\,\text{TPY}$$

Total Reduced Sulfur Emissions: Emission factors – NCASI Technical Bulletin 858, Table A-17 (mean value).

Dimethyl disulfide – $2\text{x}10^{-4}$ lb/ton CaO
Dimethyl sulfide – Not Detected
Methyl mercaptan – $4.2\text{x}10^{-4}$ lb/ton CaO

Total TRS Compounds = $6.2\text{x}10^{-4}$ lb/ton CaO

$$\text{TRS(hourly)} = \left(6.2\text{x}10^{-4}\,\frac{\text{lb TRS}}{\text{ton CaO}}\right)\left(\frac{170{,}334\text{ ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 0.012\text{ lb/hr}$$

$$\text{TRS(annual)} = \left(0.012\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 0.053\text{ TPY}$$

Green Liquor Tanks (North, South, and 280,000 gallon Units):

Volatile Organic Compound Emissions: Emission factor – NCASI TB 884, Table 4.14 = 0.066 lb/ton CaO (mean value).

Potential quantity of CaO processed = 170,334 TPY or 19.44 ton/hr

$$\text{VOC(hourly)} = \left(0.066\,\frac{\text{lb}}{\text{ton CaO}}\right)\left(\frac{170{,}334\text{ ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 1.3\text{ lb/hr}$$

$$\text{VOC(annual)} = \left(1.3\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 5.6\text{ TPY}$$

Total Reduced Sulfur Emissions: Emission factors – NCASI Technical Bulletin 858, Table A-17 (mean value).

Dimethyl disulfide – $3.1\text{x}10^{-5}$ lb/ton CaO
Dimethyl sulfide – $4.8\text{x}10^{-5}$ lb/ton CaO
Methyl mercaptan – $2.1\text{x}10^{-6}$ lb/ton CaO

Total TRS Compounds = $8.1\text{x}10^{-5}$ lb/ton CaO

$$\text{TRS(hourly)} = \left(8.1\text{x}10^{-5}\,\frac{\text{lb TRS}}{\text{ton CaO}}\right)\left(\frac{170{,}334\text{ ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\text{ hr}}\right) = 0.0016\text{ lb/hr}$$

$$\text{TRS(annual)} = \left(0.0016\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right) = 0.0069\text{ TPY}$$

Recausticizing

No. 4 Lime Kiln- Emissions Unit ID # 017 - The permitted input capacity of this unit is 82,986 pounds per hour (lb/hr) (of $CaCO_3$ & inerts)(24-hr block average). This equates to 19.44 tons/hr CaO produced. This unit has a venturi scrubber to control particulate matter (PM/PM_{10}) emissions and sulfur dioxide (SO_2) emissions (90% assumed). This unit will fire No. 6 fuel oil with a maximum sulfur content of 2.35% (by weight) to support combustion in the kiln.

	Current Title V Limits 1070005-029-AV		**Proposed Title V Limits**	
Pollutant	**lb/hr**	**TPY**	**lb/hr**	**TPY**
PM	26.0	113.9	29.7	130.2
PM_{10}	26.0	113.9	29.2	128.0
TRS	4.0	17.5	5.7	25.1
SO_2	10.9	47.7	9.1	40.0
SAM	---	---	0.4	1.8
NO_x	50.3	223.3	67.9	297.4
CO	7.3	32.0	16.3	71.5
VOC	17.2	75.3	9.4	41.4
Lead	---	---	0.056	0.25

Particulate Matter Emissions: Current Title V Permit Limits: 26.0 lb/hr and 113.9 tons per year (TPY) - previous BACT determination – permit issued 5/31/1992. Based on 0.081 grains/dscf at 10% O_2.

Proposed Title V Permit Limits of 29.7 lb/hr and 130.2 TPY shown by the calculations below.

Flow rate at 10% O_2 = 54,200 dscfm as explained in letter dated April 14, 2005 submitted to Trina Vielhauer.

PM limit = 0.064 grains/dscf is based on MACT II limit.
dscfm = dry standard cubic feet per minute

$$PM(\text{hourly}) = \left(\frac{54{,}200\ \text{dscf}}{\text{min}}\right)\left(\frac{0.064\ \text{grains}}{\text{dscf}}\right)\left(\frac{\text{lb}}{7{,}000\ \text{grains}}\right)\left(\frac{60\,\text{min}}{\text{hr}}\right) = 29.7\ \text{lb/hr}$$

$$PM(\text{annual}) = \left(29.7\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 130.2\ \text{TPY}$$

PM_{10} assumed to be 98.3% PM, based on AP-42 Table 10.2-4 (9/90-reformatted 1/95) for a lime kiln with a venturi scrubber for control.

$$PM_{10}(\text{hourly}) = \left(29.7\frac{\text{lb}}{\text{hr}}\right)x0.983 = 29.2\ \text{lb/hr}$$

$$PM_{10}(\text{annual}) = (130.2\ \text{TPY})x0.983 = 128.0\ \text{TPY}$$

TRS Emissions: Current Title V Permit Limits: 4.0 lb/hr (12-hr average) and 17.5 TPY as H_2S - based on 20 ppmvd at 10% O_2.

Proposed Title V Permit Limits of 5.7 lb/hr and 25.1 TPY shown by the calculations listed below, based on 20 ppmvd at 10% O_2 and flow rate of 54,200 dscf.

$$\text{TRS(hourly)} =$$

$$\left(\frac{20\ \text{ft}^3}{10^6\ \text{ft}^3}(\text{ppmvd})\right)\left(\frac{2{,}116.8\ \text{lb}}{\text{ft}^2}\right)\left(\frac{\text{lb}-\text{mole}-\text{R}}{1{,}545.6\ \text{ft}-\text{lb}_f}\right)\left(\frac{1}{528\ \text{R}}\right)\left(\frac{34\ \text{lb}}{\text{lb}-\text{mole}}\right)\left(\frac{54{,}200\ \text{dscf}}{\text{min}}\right)\left(\frac{60\ \text{min}}{\text{hr}}\right) = 5.7\ \text{lb/hr}$$

$$\text{TRS(annual)} = \left(5.7\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 25.1\ \text{TPY}$$

Sulfur Dioxide Emissions:

Current Title V Permit Limits: 10.9 lb/hr and 47.7 TPY previous BACT determination – permit issued 5/31/1992. Based on 0.3 lb/ADTP and 72.9 ADTP/hr or 638,604 ADTP/yr and 50% efficiency for SO_2 reduction.

Proposed Title V Permit Limits of 9.1 lb/hr and 40.0 TPY shown by the calculations listed below.

Based on emission factor of 0.47 lbs/ton CaO (NCASI TB 646, February 1993 – from Table 13, average of all the oil-fired kiln values - 0.18, 0.02, 0.45, 0.07, 1.63).

$$SO_2\,\text{(hourly)} = \left(\frac{19.44\ \text{ton CaO}}{\text{hr}}\right)\left(\frac{0.47\ \text{lb}}{\text{ton CaO}}\right) = 9.1\ \text{lb/hr}$$

$$SO_2\,\text{(annual)} = \left(9.1\ \frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 40.0\ \text{TPY}$$

Sulfuric Acid Mist Emissions:

Current Title V limits-None. Proposed Title V Permit Limits of 0.4 lb/hr and 1.8 TPY, as shown by the calculations listed below, are based on AP-42 emission factors of 5.7S lb/10^3 gal for SO_3 and 157S lb/10^3 gal for SO_2 (Table 1.3-1 (9/98)). The ratio of SO_3 to SO_2 is 3.6%, and then SO_3 was converted to sulfuric acid mist (SAM) by multiplying by ratio of molecular weights (x 98/80).

$$\text{SAM(hourly)} =$$

$$\left(9.1\frac{\text{lb}}{\text{hr}}\right)\left(\frac{3.6\%}{100\%}\right) = \left(0.33\frac{\text{lb}}{\text{hr}}\ SO_3\right)\left(\frac{98\ \text{lb SAM}}{\text{lb}-\text{mole SAM}}\right)\left(\frac{\text{lb}-\text{mole SAM}}{\text{lb}-\text{mole }SO_3}\right)\left(\frac{\text{lb}-\text{mole }SO_3}{80\ \text{lb }SO_3}\right) = 0.4\ \text{lb/hr}$$

$$\text{SAM(annual)} = \left(0.4\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 1.8\ \text{TPY}$$

Nitrogen Oxides Emissions: Current Title V Permit Limits: 50.3 lb/hr and 223.3 TPY - previous BACT determination – permit issued 5/31/1992. Based on 290 ppmvd at 10% O_2

Proposed Title V Permit Limits of 67.9 lb/hr and 297.4 TPY based on 175 ppmvd at 10% oxygen and flow rate of 54,200 dscf. Corresponding mass emission rate calculated as follows:

NOx(hourly) =

$$\left(\frac{175\,\text{ft}^3}{10^6\,\text{ft}^3}(\text{ppmvd})\right)\left(\frac{2{,}116.8\text{ lb}}{\text{ft}^2}\right)\left(\frac{\text{lb}-\text{mole}-\text{R}}{1{,}545.6\text{ ft}-\text{lb}_\text{f}}\right)\left(\frac{1}{528\text{ R}}\right)\left(\frac{46\text{ lb}}{\text{lb}-\text{mole}}\right)\left(\frac{54{,}200\text{ dscf}}{\text{min}}\right)\left(\frac{60\text{ min}}{\text{hr}}\right)=67.9\text{ lb/hr}$$

$$\text{NOx(annual)}=\left(67.9\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)=297.4\text{ TPY}$$

Carbon Monoxide Emissions: Current Title V Permit Limits: 7.3 lb/hr and 32.0 TPY. Previous BACT determination – permit issued 5/31/1992. Based on 69 ppmvd at 10% oxygen.

Proposed Title V Permit Limits of 16.3 lb/hr and 71.5 TPY based on 69 ppmvd at 10% oxygen and 54,200 dscf.

CO(hourly) =

$$\left(\frac{69\text{ ft}^3}{10^6\text{ ft}^3}(\text{ppmvd})\right)\left(\frac{2{,}116.8\text{ lb}}{\text{ft}^2}\right)\left(\frac{\text{lb}-\text{mole}-\text{R}}{1{,}545.6\text{ ft}-\text{lb}_\text{f}}\right)\left(\frac{1}{528\text{ R}}\right)\left(\frac{28\text{ lb}}{\text{lb}-\text{mole}}\right)\left(\frac{54{,}200\text{ dscf}}{\text{min}}\right)\left(\frac{60\,\text{min}}{\text{hr}}\right)=16.3\text{ lb/hr}$$

$$\text{CO(annual)}=\left(16.3\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)=71.5\text{ TPY}$$

Volatile Organic Compound Emissions: Current Title V Permit Limits: 17.2 lb/hr and 75.3 TPY previous BACT determinations – permit issued 5/31/1992 Based on 185 ppmvd @ 10% oxygen

Proposed Title V Permit Limits of 70 ppmvd (existing limit) or 9.4 lb/hr and 41.4 TPY based on 70 ppmvd @ 10% oxygen and 54,200 dscf. Corresponding mass emission rate calculated as follows:

VOC(hourly) =

$$\left(\frac{70\text{ ft}^3}{10^6\text{ ft}^3}(\text{ppmvd})\right)\left(\frac{2{,}116.8\text{ lb}}{\text{ft}^2}\right)\left(\frac{\text{lb}-\text{mole}-\text{R}}{1{,}545.6\text{ ft}-\text{lb}_\text{f}}\right)\left(\frac{1}{528\text{ R}}\right)\left(\frac{16\text{ lb}}{\text{lb}-\text{mole}}\right)\left(\frac{54{,}200\text{ dscf}}{\text{min}}\right)\left(\frac{60\text{ min}}{\text{hr}}\right)=9.4\text{ lb/hr}$$

$$\text{VOC(annual)}=\left(9.4\,\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\text{ hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)=41.4\text{ TPY}$$

Lead Emissions: Current Title V Permit Limits-None. Maximum emissions of 0.056 lb/hr and 0.25 TPY shown by the calculations listed below. Emission factor = $2.9\text{x}10^{-3}$ lb/ton CaO from NCASI TB #858, Table 16C, February 2003, using median of all oil-fired kilns.

$$\text{Pb(hourly)} = \left(\frac{2.9\text{x}10^{-3}\ \text{lb}}{\text{ton CaO}}\right)\left(\frac{19.44\ \text{ton CaO}}{\text{hr}}\right) = 0.056\ \text{lb/hr}$$

$$\text{Pb(annual)} = \left(0.056\ \frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right) = 0.25\ \text{TPY}$$

Caustic Area- Emissions Unit ID # 042 - This area includes a number of miscellaneous fugitive and point emission sources as listed below:

Lime (White Liquor) Slakers (Nos. 1 & 2)

Particulate Matter Emissions: Emission factor – NCASI TB 884, Table 4.14; mean = 0.031 lb/ton CaO. 170,334 ton CaO processed in both slakers.

$$\mathrm{PM(hourly)} = \left(0.031\frac{\mathrm{lb\,PM}}{\mathrm{ton\,CaO}}\right)\left(\frac{170{,}334\,\mathrm{ton\,CaO}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}760\,\mathrm{hr}}\right) = 0.60\ \mathrm{lb/hr}$$

$$\mathrm{PM(annual)} = \left(0.60\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 2.6\,\mathrm{TPY}$$

PM_{10} assumed to be 100% PM.

$$\mathrm{PM_{10}(hourly)} = \left(0.60\frac{\mathrm{lb}}{\mathrm{hr}}\right)\mathrm{x}1 = 0.60\ \mathrm{lb/hr}$$

$$\mathrm{PM_{10}(annual)} = (2.6\ \mathrm{TPY})\mathrm{x}1 = 2.6\ \mathrm{TPY}$$

Volatile Organic Compound Emissions: Emission factor = 0.041 lb/ton CaO, NCASI TB 676, Table VII.A.5, Mill M (only mill with separate slaker and causticizer exhausts); mean value.

$$\mathrm{VOC(hourly)} = \left(0.041\frac{\mathrm{lb\,VOC}}{\mathrm{ton\,CaO}}\right)\left(\frac{170{,}334\,\mathrm{ton\,CaO}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}760\,\mathrm{hr}}\right) = 0.80\ \mathrm{lb/hr}$$

$$\mathrm{VOC(annual)} = \left(0.80\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 3.5\,\mathrm{TPY}$$

Total Reduced Sulfur Emissions: Emission factor = 0.045 lb/ton CaO, NCASI TB 849, Table 24, mean value.

$$\mathrm{TRS(hourly)} = \left(0.045\frac{\mathrm{lb\,TRS}}{\mathrm{ton\,CaO}}\right)\left(\frac{170{,}334\,\mathrm{ton\,CaO}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}760\,\mathrm{hr}}\right) = 0.88\ \mathrm{lb/hr}$$

$$\mathrm{TRS(annual)} = \left(0.88\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 3.8\,\mathrm{TPY}$$

White Liquor Storage Tanks (5 units)

Volatile Organic Compound Emissions: Emission factor – NCASI TB 858, Table A-17 = 0.0056 lb/ton CaO (mean value).

$$\mathrm{VOC(hourly)} = \left(0.0056\frac{\mathrm{lb\,VOC}}{\mathrm{ton\,CaO}}\right)\left(\frac{170{,}334\,\mathrm{ton\,CaO}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}760\,\mathrm{hr}}\right) = 0.11\ \mathrm{lb/hr}$$

$$\text{VOC(annual)} = \left(0.11\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.48\,\text{TPY}$$

White Liquor Clarifiers (East and West Units)

Volatile Organic Compound Emissions: Emission factor – NCASI TB 858, Table A-17 = 0.0056 lb/ton CaO, mean value.

$$\text{VOC(hourly)} = \left(0.0056\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{170{,}334\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 0.11\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(0.11\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.48\,\text{TPY}$$

Lime Mud Washer Tanks (4 units)

Volatile Organic Compound Emissions: Emission factor = 0.085 lb VOC/ton CaO processed NCASI TB #676, Table VIII.A.1-DCA3 (mean value).

$$\text{VOC(hourly)} = \left(0.085\frac{\text{lb VOC}}{\text{ton CaO}}\right)\left(\frac{170{,}334\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 1.65\ \text{lb/hr}$$

$$\text{VOC(annual)} = \left(1.65\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 7.2\,\text{TPY}$$

Total Reduced Sulfur Emissions: Emission factor from NCASI TB# 676, Table VIII.A.1-DCA3, mean values, with values less than the detection limit represented as zero.

Dimethyl sulfide – $1.2\text{x}10^{-3}$ lb/ton CaO
Methyl mercaptan – $7.4\text{x}10^{-4}$ lb/ton CaO

Total TRS Compounds = $1.9\text{x}10^{-3}$ lb/ton CaO

$$\text{TRS(hourly)} = \left(0.0019\frac{\text{lb TRS}}{\text{ton CaO}}\right)\left(\frac{170{,}334\,\text{ton CaO}}{\text{yr}}\right)\left(\frac{\text{yr}}{8{,}760\,\text{hr}}\right) = 0.04\ \text{lb/hr}$$

$$\text{TRS(annual)} = \left(0.04\frac{\text{lb}}{\text{hr}}\right)\left(\frac{8{,}760\,\text{hr}}{\text{yr}}\right)\left(\frac{\text{ton}}{2{,}000\,\text{lb}}\right) = 0.16\,\text{TPY}$$

Lime Mud Splitter Box Tank

Volatile Organic Compound Emissions: Emission factor = 0.085 lb VOC/ton CaO processed NCASI TB #676, Table VIII.A.1-DCA3, mean value.

$$\mathrm{VOC(hourly)} = \left(0.085\frac{\mathrm{lb\,VOC}}{\mathrm{ton\,CaO}}\right)\left(\frac{170{,}334\ \mathrm{ton\,CaO}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}760\,\mathrm{hr}}\right) = 1.65\ \mathrm{lb/hr}$$

$$\mathrm{VOC(annual)} = \left(1.65\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 7.2\,\mathrm{TPY}$$

Total Reduced Sulfur Emissions: Emission factor from NCASI TB# 676, Table VIII.A.1-DCA3, mean values, with values less than the detection limit represented as zero.

Dimethyl sulfide – $1.2\mathrm{x}10^{-3}$ lb/ton CaO
Methyl mercaptan – $7.4\mathrm{x}10^{-4}$ lb/ton CaO

Total TRS Compounds = $1.9\mathrm{x}10^{-3}$ lb/ton CaO

$$\mathrm{TRS(hourly)} = \left(0.0019\frac{\mathrm{lb\,TRS}}{\mathrm{ton\,CaO}}\right)\left(\frac{170{,}334\ \mathrm{ton\,CaO}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}760\,\mathrm{hr}}\right) = 0.04\ \mathrm{lb/hr}$$

$$\mathrm{TRS(annual)} = \left(0.04\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 0.16\,\mathrm{TPY}$$

__Causticizer Tanks (Nos. 1A, 1B, 2,3)__

Volatile Organic Compound Emissions: Emission factor – NCASI TB 676, Table VII.A.5, Mill M (only mill with separate slaker and causticizer exhausts); mean = 0.00083 lb/ton CaO.

$$\mathrm{VOC(hourly)} = \left(0.00083\frac{\mathrm{lb\,VOC}}{\mathrm{ton\,CaO}}\right)\left(\frac{170{,}334\ \mathrm{ton\,CaO}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}760\,\mathrm{hr}}\right) = 0.016\ \mathrm{lb/hr}$$

$$\mathrm{VOC(annual)} = \left(0.016\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 0.07\,\mathrm{TPY}$$

Total Reduced Sulfur Emissions: Emission factor – NCASI TB 849, Table 24; mean = 0.019 lb/ton CaO (as sulfur); factor as hydrogen sulfide = 0.019 x 34/32 = 0.020 lb/ton CaO.

$$\mathrm{TRS(hourly)} = \left(0.020\frac{\mathrm{lb\,TRS}}{\mathrm{ton\,CaO}}\right)\left(\frac{170{,}334\ \mathrm{ton\,CaO}}{\mathrm{yr}}\right)\left(\frac{\mathrm{yr}}{8{,}760\,\mathrm{hr}}\right) = 0.39\ \mathrm{lb/hr}$$

$$\mathrm{TRS(annual)} = \left(0.39\frac{\mathrm{lb}}{\mathrm{hr}}\right)\left(\frac{8{,}760\,\mathrm{hr}}{\mathrm{yr}}\right)\left(\frac{\mathrm{ton}}{2{,}000\,\mathrm{lb}}\right) = 1.7\,\mathrm{TPY}$$