Application

AIR CONSTRUCTION PERMIT APPLICATION

Georgia-Pacific Consumer Operations LLC

Prepared For: Georgia-Pacific Consumer Operations LLC
P.O. Box 919
Palatka, FL 32178 USA

Submitted By: Golder Associates Inc.
6026 NW 1st Place
Gainesville, FL 32607 USA

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January 2011 **103-87695**

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Golder Associates

APPLICATION FOR AIR PERMIT

LONG FORM

Department of
Environmental Protection
Division of Air Resource Management
APPLICATION FOR AIR PERMIT - LONG FORM
I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:
- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:
- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

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To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Georgia-Pacific Consumer Operations LLC**	
2. Site Name: **Palatka Mill**	
3. Facility Identification Number: **1070005**	
4. Facility Location... Street Address or Other Locator: **215 County Road 216** 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: **Ron Reynolds, Environmental Engineer – Air Quality**
2. Application Contact Mailing Address... Organization/Firm: **Georgia-Pacific Consumer Operations LLC** Street Address: **P.O. Box 919** City: **Palatka** State: **FL** Zip Code: **32178-0919**
3. Application Contact Telephone Numbers... Telephone: **(386) 329-0967** ext. Fax: **(368) 328-0014**
4. Application Contact E-mail Address: **ron.reynolds@gapac.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 1/10/11	3. PSD Number (if applicable):
2. Project Number(s): 1070005-066-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

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

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

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

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

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

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

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

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

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

Application Comment

This application is being submitted to replace the existing No. 6 fuel oil burner in the No. 4 Combination Boiler (EU ID 016) with a new natural gas burner. No. 6 fuel oil will no longer be burned in the boiler. Natural gas will be burned alone or in combination with wood/bark.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
016	No. 4 Combination Boiler	N/A	N/A

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 : **Gary L. Frost, Vice-President Operations**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Georgia-Pacific Consumer Operations LLC** Street Address: **P.O. Box 919** City: **Palatka** State: **FL** Zip Code: **32178**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(386) 329-0063** ext. Fax: **(386) 312-1135**
4.	Owner/Authorized Representative E-mail Address: **gary.frost@gapac.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* Signature Date 7 JAN 2014

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation 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 or CAIR 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 E-mail 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: **6026 NW 1st Place** City: **Gainesville** State: **FL** Zip Code: **32607**	
3. Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext. Fax: **(352) 336-6603**	
4. Professional Engineer E-mail 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 (seal)

1/6/11 — Date

* 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) **3,283.4**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **29 / 41 / 00** 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: **Ron Reynolds, Environmental Engineer – Air Quality**
2. Facility Contact Mailing Address... Organization/Firm: **Georgia-Pacific Consumer Operations LLC** Street Address: **P.O. Box 919** City: **Palatka** State: **FL** Zip Code: **32178**
3. Facility Contact Telephone Numbers: Telephone: **(386) 329-0967** ext. Fax: **(386) 328-0014**
4. Facility Contact E-mail Address: **ron.reynolds@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 E-mail 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:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter Total – PM	A	N
Particulate Matter – PM10	A	N
Particulate Matter – PM2.5	A	N
Sulfur Dioxide – SO2	A	N
Nitrogen Oxides – NOx	A	N
Carbon Monoxide – CO	A	N
Volatile Organic Compounds – VOC	A	N
Lead – Pb	A	N
Sulfuric Acid Mist – SAM	A	N
Total Reduced Sulfur – TRS	A	N
Benzene – H017	A	N
m-Cresol – H051	A	N
Formaldehyde – H095	A	N
Hexachlorocyclopentadiene – H100	A	N
Methanol – H115	A	N
Naphthalene – H132	A	N
Phenol – H144	A	N
Toluene – H169	A	N
1,2,4-Trichlorobenzene – H174	A	N
o-Xylene – H187	A	N
Hazardous Air Pollutants – HAPS	A	N

B. EMISSIONS CAPS

<u>Facility-Wide or Multi-Unit Emissions Caps</u>

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

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: 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: GP-FI-C3 ☐ Previously Submitted, Date:__________

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, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: Part B
3.	Rule Applicability Analysis: ☒ Attached, Document ID: Part B
4.	List of Exempt Emissions Units: ☐ Attached, Document ID:__________ ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification: ☐ Attached, Document ID:__________ ☒ Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications

1.	List of Exempt Emissions Units: ☐ 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 Onsite 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

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1. Acid Rain Program Forms:

   Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable (not an Acid Rain source)

   Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable

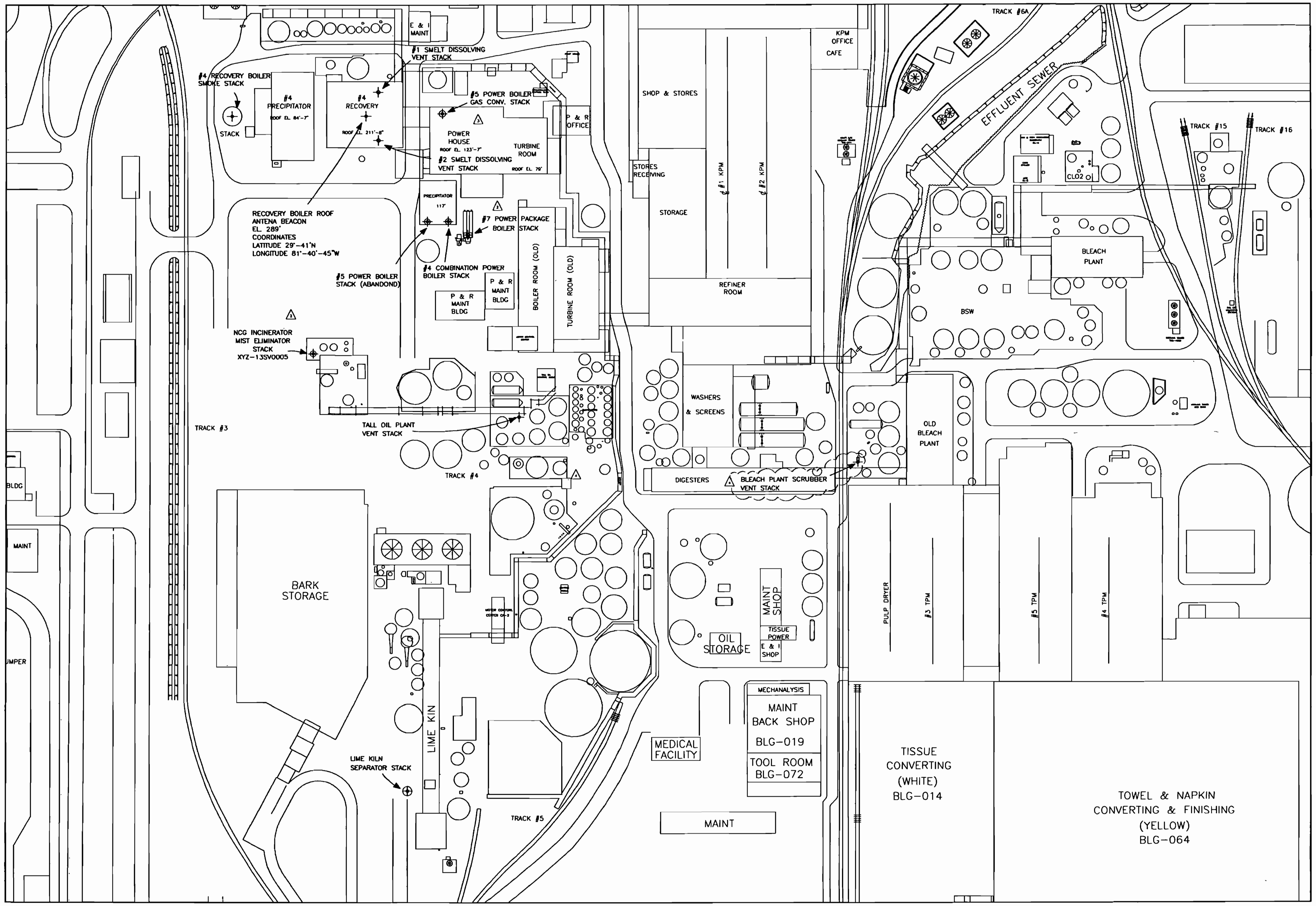
   New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable (not a CAIR source)

Additional Requirements Comment

ATTACHMENT GP-FI-C1

FACILITY PLOT PLAN



NOTES

MILL STACKS

	MILL STACKS	EQUIP NO.	BASE EL.	HEIGHT	STACK EL.	ID.	REF. DWG.	REF. DWG.
	NCG INCINERATOR MIST ELIMINATOR STACK	XYZ-13SV0005	20'	250'-1 1/2'	270'-1 1/2"	25.5"	G-P 291-8595ME-000-0039-002	
	#4 COMBINATION BOILER STACK	BHP-2003	121'-6"	133'-8	255'-2"	8'	Research - Cottrell 291-5219/5220-1-03	
ABANDON	#5 POWER BOILER STACK	BHP-2006	121'-6"	133'-8"	255'-2"	8'	Research - Cottrell 291-5219/5220-1-03	
	#5 POWER BOILER GAS CONVERSION STACK	BHP-	123'-7 1/8"	50'-0"	173'-7 1/8"	9'	G-P 291-5220ME-002-0015-004, 005	
	#4 RECOVERY BOILER SMOKE STACK	XYZ-5521	19'	230'	249'	12'	Rust Eng. 27-68-37	Peabody Dwg. 5170-2
	#1 SMELT DISSOLVING VENT STACK	XYZ-5514	33'-3"	188'-9"	222'	4'-11"	Rust Eng. 27-68-51	Zurn Dwg. 6-750-DE1
	#2 SMELT DISSOLVING VENT STACK	XYZ-5515	33'-3"	188'-9"	222'	4'-11"	Rust Eng. 27-68-51	Zurn Dwg. 6-750-DE2X
	LIME KILN SEPARATOR STACK	SPR-5057	71'-6"	77'-6"	149'	4'-5 1/4"	Rust Eng. 27-16-50	Zurn Dwg. C-36470-2, D-39846
	TALL OIL PLANT VENT STACK		19'-0"	64'-6"	83'-6"	1'-4"	G-P 297-7810-034	Wallace-Murray Dwg. File 297-7810-12-01
	#7 POWER PACKAGE BOILER STACK	BHP-2007	36' ±	20'-4"	56' ±	6'	G-P 291-5220-001-0019-002	
	BLEACH PLANT SCRUBBER VENT STACK	XYZ-	27'-1"	81'-8"	108'-9"	3'-7"	G-P 295-5614-302-05	

CONSULTANT NO.

REV.	DATE	DESCRIPTION	DRN. / CH'D.	AP'D
4	6/1/99	ADDED BLEACH PLANT SCRUBBER STACK	VHT	
3	5/18/99	ADDED NO.5 POWER BLR GAS CONV. STACK	VHT	
2	11/10/05	NO. 7 POWER PACKAGE BOILER WAS NO.6	VHT	
		ADDED NCG INCINERATOR MIST ELEM STACK		
1	6/14/05	REPLACED BORDER	JEM / VHT	

CROSS-REFERENCE NO.

HUDSON NO.

Georgia-Pacific

THE GROWTH COMPANY

PALATKA OPERATIONS

MILL STACKS
LOCATION PLAN
POLLUTION CONTROL

DRAWN	VHT	10/29/99	SCALE
CHECKED			RES NO.
APPROVED			FILENAME 00010363.dwg
APPROVED			AREA B3

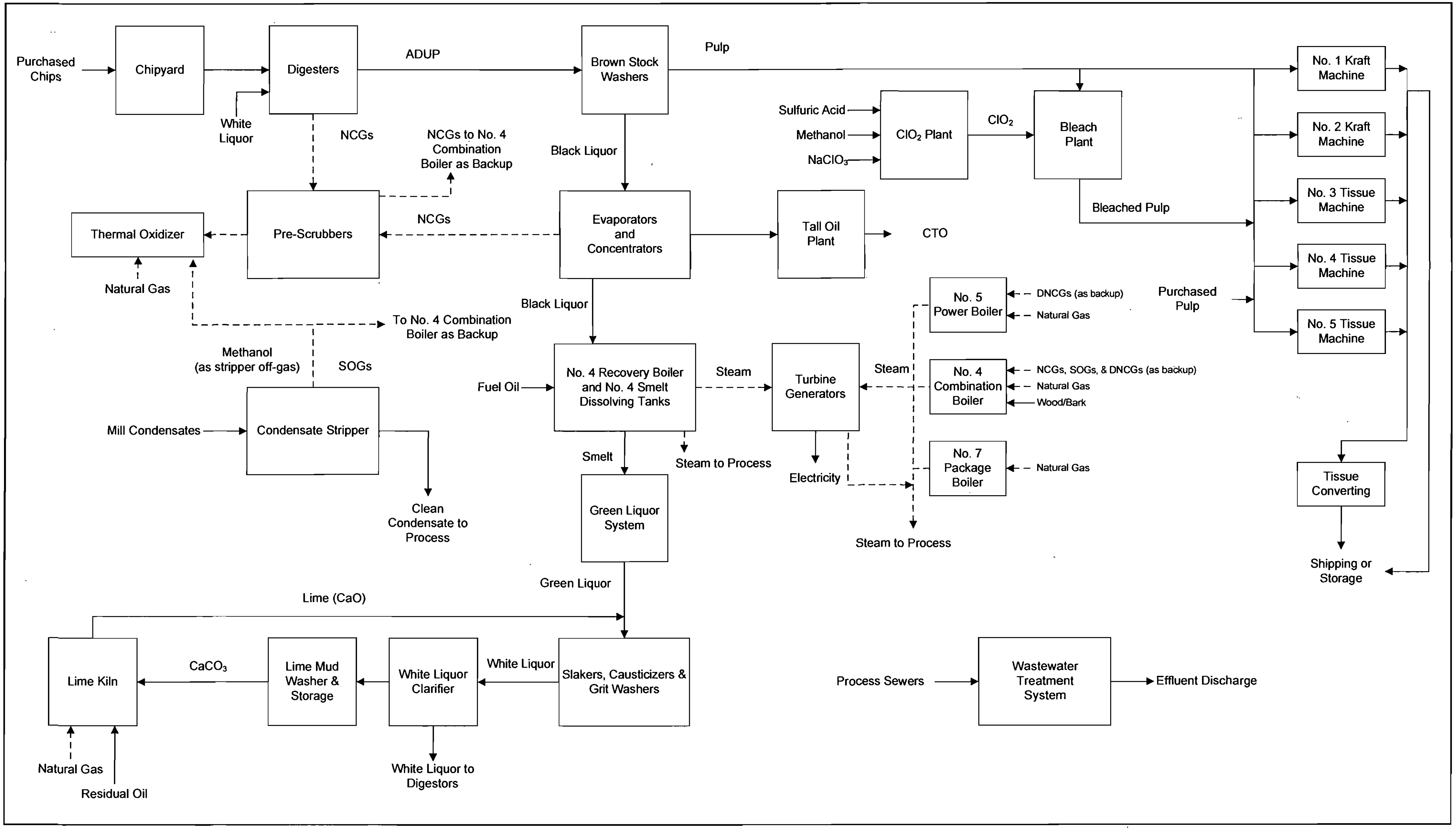
G-P DRAWING NO.
290-8464MS-000-0016-001

CONSULTANT:

REV: 4

ATTACHMENT GP-FI-C2

PROCESS FLOW DIAGRAM



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

Notes:
ADUP = Air Dried Unbleached Pulp
CTO = Crude Tall Oil
Solid/Liquid ——→
Gas - - - - - →

Golder Associates

ATTACHMENT GP-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF
UNCONFINED PARTICULATE MATTER

ATTACHMENT GP-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

- Conveyors that are covered or enclosed where feasible and practical
- Paved roads entering and exiting the plant
- Limiting vehicle speeds
- Good housekeeping practices

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 an initial, revised or renewal 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. 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 an 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 or 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. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes 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

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

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A			**26**

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    The No. 4 Combination Boiler burns wood/bark and natural gas to produce steam that is used by the mill. Particulate matter emissions are controlled by a centrifugal collector and an electrostatic precipitator (ESP). The boiler serves as a backup destruction device for non-condensable gases (NCGs) and stripper off-gases (SOGs). When operating as the NCG destruction device, a spray tower pre-scrubber is used to remove sulfur from the batch digesting system streams, and a separate spray tower pre-scrubber is used to remove sulfur from the multiple effect evaporator (MEE) system streams prior to destruction in the boiler. NCGs from the turpentine condensing system are vented directly to the boiler for destruction.

Emissions Unit Control Equipment/Method: Control 1 of 2

1. Control Equipment/Method Description: **Centrifugal Collector**
2. Control Device or Method Code: **007**

Emissions Unit Control Equipment/Method: Control 2 of 2

1. Control Equipment/Method Description: **Electrostatic Precipitator**
2. Control Device or Method Code: **010**

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:
2. Control Device or Method Code:

EMISSIONS UNIT INFORMATION
Section [1]
No. 4 Combination Boiler

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **57 TPH carbonaceous fuel (bark/wood chips)**	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **512.7** 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 natural gas, as a 24-hour average. Maximum heat input rate when firing natural gas only is 427 MMBtu/hr.**	

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: **422**°F	9. Actual Volumetric Flow Rate: **229,403** acfm	10. Water Vapor: **16.3** %
11. Maximum Dry Standard Flow Rate: **116,730** dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters based on May 17, 2010 compliance test.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Wood and bark**		
2. Source Classification Code (SCC): **1-02-019-02**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **57**	5. Maximum Annual Rate: **499,320**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **9**
10. Segment Comment: **Maximum hourly rate based on 512.7 MMBtu/hr and 9 MMBtu/ton wood/bark. Maximum annual rate based on continuous (8,760 hr/yr) operation.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial: Natural Gas > 100 MMBtu/hr**		
2. Source Classification Code (SCC): **1-02-006-01**	3. SCC Units: **Million cubic feet burned**	
4. Maximum Hourly Rate: **0.427**	5. Maximum Annual Rate: **3,740.5**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,000**
10. Segment Comment: **Maximum hourly rate based on 427 MMBtu/hr.**		

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
PM10	007	010	NS
PM2.5	007	010	NS
SO2			NS
NOx			NS
CO			NS
VOC			NS
SAM			NS
Lead – Pb			NS
Mercury – Hg			NS
Acetaldehyde – H001			NS
Acrolein – H006			NS
Benzene – H017			NS
Chlorine – H038			NS
Formaldehyde – H095			NS
Hexane – H104			NS
Hydrochloric Acid – H106			NS
Manganese – H113			NS
Methanol – H115			NS
Methylene Chloride – H128			NS
Toluene – H169			NS
HAPS			NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **12.82** lb/hour **56.14** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.025 lb/MMBtu from wood/bark combustion** Reference: **NCASI Technical Bulletin 884, Table 9.6a**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **827.99** tons/year	8.b. Baseline 24-month Period: From: **01/2004** To: **12/2005**
9.a. Projected Actual Emissions (if required): **37.61** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: 0.025 lb/MMBtu x 512.7 MMBtu/hr = 12.82 lb/hr

Annual: 12.82 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 56.14 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Emissions represent the worst-case fuel firing scenario. Emission factor for natural gas combustion is 0.006 lb SO_2/MMBtu from AP-42, Table 1.4-2.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **128.18** lb/hour **561.41** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.25 lb/MMBtu from wood/bark combustion** Reference: **Based on conservative engineering estimate**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **398.75** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **426.19** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: 0.25 lb/MMBtu x 512.7 MMBtu/hr = 128.18 lb/hr

Annual: 128.18 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 561.41 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Emissions represent the worst-case fuel firing scenario. Emission factor for natural gas combustion is 0.15 lb NO_x/MMBtu from vendor estimates.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **307.62** lb/hour **1,347.38** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.6 lb/MMBtu from wood/bark combustion** Reference: **NCASI Technical Bulletin No. 884, Table 9.6a**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **817.65** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **932.50** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: 0.6 lb/MMBtu x 512.7 MMBtu/hr = 307.62 lb/hr

Annual: 307.62 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 1,347.38 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Emissions represent the worst-case fuel firing scenario. Emission factor for natural gas combustion is 0.1 lb CO/MMBtu from vendor estimates.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **153.81** lb/hour **673.69** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.3 lb/MMBtu from wood/bark combustion** Reference: **Rule 62-296.410(1)(b)2., F.A.C.**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **139.12** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **140.08** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **Hourly: 0.3 lb/MMBtu x 512.7 MMBtu/hr = 153.81 lb/hr** **Annual: 153.81 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 673.69 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions represent the worst-case fuel firing scenario. Emission factor for natural gas combustion is 0.0076 lb PM/MMBtu from AP-42, Table 1.4-2.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.3 lb/MMBtu for carbonaceous fuel firing**	4. Equivalent Allowable Emissions: **153.81** lb/hour **673.69** tons/year
5. Method of Compliance: **EPA Method 5 or 29**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.410(1)(b)2., F.A.C. for carbonaceous fuel firing**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/MMBtu for fossil fuel firing**	4. Equivalent Allowable Emissions: **42.7** lb/hour **187.03** tons/year
5. Method of Compliance: **EPA Method 5 or 29**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.410(1)(b)2., F.A.C. for fossil fuel firing**	

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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **113.82** lb/hour **498.53** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **74% of PM Emissions** Reference: **NCASI Technical Bulletin No. 884, Table 9.6b**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **108.39** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **110.96** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: 153.81 lb/hr PM x 0.74 lb PM_{10}/lb PM = 113.82 lb/hr PM_{10}

Annual: 113.82 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 498.53 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Emissions represent the worst-case fuel firing scenario. Emission factor is for wood/bark combustion with ESP control. Emission factor for natural gas firing is 100 percent of PM emissions from AP-42, Table 1.4-2.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM2.5**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **99.98** lb/hour **437.90** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **65% of PM Emissions** Reference: **NCASI Technical Bulletin No. 884, Table 9.6b**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **96.62** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **100.88** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: 153.81 lb/hr PM x 0.65 lb $PM_{2.5}$/lb PM = 99.98 lb/hr $PM_{2.5}$

Annual: 99.98 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 437.90 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Emissions represent the worst-case fuel firing scenario. Emission factor is for wood/bark combustion with ESP control. Emission factor for natural gas firing is 100 percent of PM emissions from AP-42, Table 1.4-2.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17.43** lb/hour **76.35** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.034 lb/MMBtu from wood/bark combustion** Reference: **NCASI Technical Bulletin No. 884, Table 9.6a**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **46.33** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **52.78** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: 0.034 lb/MMBtu x 512.7 MMBtu/hr = 17.43 lb/hr

Annual: 17.43 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 76.35 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Emissions represent the worst-case fuel firing scenario. Emission factor for natural gas combustion is 0.0055 lb VOC/MMBtu from AP-42, Table 1.4-2.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.57** lb/hour **2.50** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **4.45% of SO_2 emissions** Reference: **AP-42, Table 1.3-1**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **36.82** tons/year	8.b. Baseline 24-month Period: From: **01/2004** To: **12/2005**
9.a. Projected Actual Emissions (if required): **1.67** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: 12.82 lb/hr SO_2 x 5.7 lb SO_3/157 lb SO_2 x 98 lb H_2SO_4/80 lb SO_3 = 0.57 lb/hr

Annual: 0.57 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 2.50 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Emissions represent the worst-case fuel firing scenario. Emission factor for natural gas combustion is assumed the same as for wood/bark combustion.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0025** lb/hour **0.01** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **4.95×10^{-6} lb/MMBtu for wood/bark combustion** Reference: **NCASI Technical Bulletin No. 973, Table 7.2**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **0.0100** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **0.0076** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: 4.95×10^{-6} lb/MMBtu x 512.7 MMBtu/hr = 0.0025 lb/hr

Annual: 0.0025 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 0.01 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Emissions represent the worst-case fuel firing scenario. Emission factor for natural gas combustion is 5×10^{-7} lb Pb/MMBtu from AP-42, Table 1.4-2.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Hg**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0003** lb/hour **0.001** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5.73×10^{-7} lb/MMBtu for wood/bark combustion** Reference: **Previous Stack Testing**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **0.0010** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **0.0009** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: 5.73×10^{-7} lb/MMBtu x 512.7 MMBtu/hr = 0.0003 lb/hr

Annual: 0.0003 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 0.001 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Emissions represent the worst-case fuel firing scenario. Emission factor for natural gas combustion is 2.6×10^{-7} lb Hg/MMBtu from AP-42, Table 1.4-4.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Applies to natural gas firing alone.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

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: **EPA Method 9**	
5. Visible Emissions Comment: **Applies to wood/bark firing alone or in combination with natural gas.**	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H 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: ______ ☒ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

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

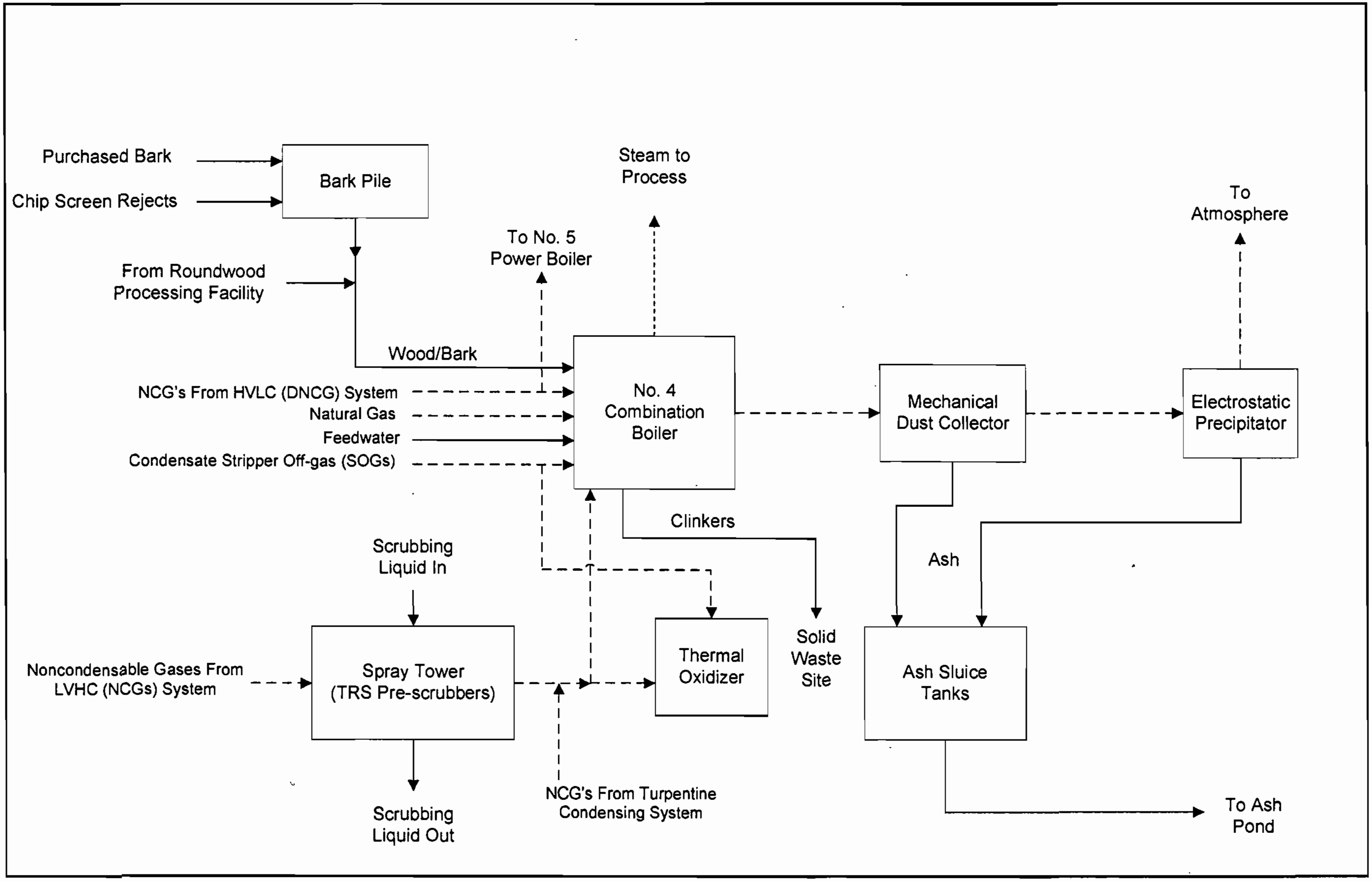
Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: ☐ Attached, Document ID: ____________
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

Additional Requirements Comment

ATTACHMENT GP-EU1-I1

PROCESS FLOW DIAGRAM



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

Process Flow Legend

Solid/Liquid
Gas
Steam

Golder Associates

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ATTACHMENT GP-EU1-I2

FUEL ANALYSIS OR SPECIFICATIONS

ATTACHMENT GP-EU1-I2

NO. 4 COMBINATION BOILER
FUEL ANALYSIS

Fuel	Density (lb/gal)	Moisture (%)	Sulfur (Weight %)	Nitrogen (Weight %)	Ash (Weight %)	Heat Capacity
Carbonaceous Fuel	--	50	--	--	1.2 – 2.7	4,500 Btu/lb (wet) 9,000 Btu/lb (dry)
Natural Gas	--	--	0.1	--	--	1,000 Btu/scf

Notes: scf = standard cubic feet
Carbonaceous fuel may include wood and/or bark chips

ATTACHMENT GP-EU3-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

ATTACHMENT GP-EU1-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

CONTROL EQUIPMENT PARAMETERS
NO. 4 COMBINATION BOILER

Parameter	Primary Dust Collector (to be removed)	Secondary Dust Collector (to be removed)	Tertiary Dust Collector (to be upgraded)
Manufacturer	Zurn	Universal Oil Products Co.	Universal Products Co.
Inlet Gas Temperature	700°F	400°F	400°F
Inlet Gas Flow Rate	280,000 ACFM	225,000 ACFM	225,000 ACFM
Pressure Drop	< 3 inches of water	3 – 4 inches of water	3 – 4 inches of water
Control Efficiency	80 – 90%	85 – 90%	85 – 90%

Parameter	Electrostatic Precipitator
Manufacturer	Research Cottrell
Inlet Gas Temperature (°F)	325
Gas Flow Rate (ACFM)	455,000
Primary Voltage (V)	0 – 600
Secondary Voltage (kV dc)	0 – 90
Primary Current (A)	0 – 150
Secondary Current (A)	0 – 1.0
Control Efficiency (%)	99.5

PART B

Table of Contents

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1.0 INTRODUCTION

Georgia-Pacific Consumer Operations LLC (GP) operates a Kraft pulp and paper mill located in Palatka, Putnam County, Florida. The processes and systems at the Palatka mill include woodyard operations, pulp mill operations, chemical recovery processes, recausticizing processes, bleaching operations, utility operations, papermaking operations, and product converting systems. The Palatka mill is currently operating under Title V Operating Permit No. 1070005-064-AV, issued by the Florida Department of Environmental Protection (FDEP) on December 24, 2006, and revised January 4, 2010.

GP operates the No. 4 Combination Boiler as part of the utility operations. The boiler produces steam for use in the mill. The No. 4 Combination Boiler is permitted to burn bark/wood and No. 6 fuel oil as fuels, as well as natural gas as a startup fuel. The boiler is also the backup control device for dilute non-condensable gases (DNCGs), non-condensable gases (NCGs), and stripper off-gases (SOGs). Mechanical dust collectors and an electrostatic precipitator (ESP) are used to control particulate matter (PM) emissions from the boiler.

GP is proposing to implement three changes in regards to the No. 4 Combination Boiler:

1. Replace the current No. 6 fuel oil burners (three) in the No. 4 Combination Boiler with natural gas burners. The replacement of the burners was previously authorized under Permit No. 1070005-045-AC/PSD-FL-393. The replacement of the burners will allow the GP Palatka mill to meet the requirements of its Best Available Retrofit Technology (BART) exemption. The natural gas burners will be rated for a total maximum heat input rate not to exceed 427 million British thermal units per hour (MMBtu/hr), which is slightly greater than the rating of the existing No. 6 fuel oil burners of 418.6 MMBtu/hr. However, the new natural gas-fired burners will not increase the total heat input rating of the boiler (512.7 MMBtu/hr), nor will they increase the actual or potential steam production rate of the boiler.
2. Upgrade the existing mechanical dust collectors serving the No. 4 Combination Boiler to improve the boiler's reliability and reduce operating costs. The current control equipment for the No. 4 Combination Boiler is made up of three mechanical dust collectors (primary, secondary, and tertiary) followed by an ESP. The upgrades will make the dust collectors more energy efficient, while reducing the operation and maintenance costs.
3. Replace the steam turbine-driven induced draft (ID) fan-drive on the No. 4 Combination Boiler with an electric motor. The existing steam turbine-driven fan has experienced increasing reliability issues and maintenance cost in recent years and replacing the fan-drive with an electric motor drive will reduce these costs and downtime.

The GP Palatka mill is an existing major source under the prevention of significant deterioration (PSD) new source review (NSR) regulations. GP has performed a PSD applicability analysis for the proposed project using the "baseline actual-to-projected actual" emission comparison allowed under Rule 62-212.400(2)(a)1 of the Florida Administrative Code (F.A.C.). Based on this comparison, all emission increases due to the project are less than the PSD significant emission rates, as shown in Table 4-10 in Section 4.0. Therefore, the project will not trigger PSD new source review under federal and state air regulations.

A more detailed description of the proposed project is presented in Section 2.0. Preconstruction review requirements are discussed in Section 3.0, and air emission estimates and PSD applicability are presented in Section 4.0.

2.0 PROJECT DESCRIPTION

2.1 Existing Operations

The No. 4 Combination Boiler [Emissions Unit Identification No. (EU) 016] is currently permitted to burn the following fuels:

- Carbonaceous fuel (bark or wood chips) only or in combination with fuel oil at a maximum heat input rate of 512.7 MMBtu/hr
- No. 6 Fuel oil with a maximum sulfur content of 2.35 percent by weight with a maximum heat input rate of 418.6 MMBtu/hr and a maximum annual usage of 5.1 million gallons during any consecutive 12-month period
- On-specification used oil (blended with No. 6 fuel oil prior to being burned in the boiler)
- Natural gas as a startup fuel and as a pilot fuel for flame stabilization

The No. 4 Combination Boiler also serves as a backup incineration device for DNCGs, NCGs, and SOGs. The primary incineration device for NCGs and SOGs is the Thermal Oxidizer (EU 037). The No. 5 Power Boiler (EU 015) serves as the primary incineration device for DNCGs. A spray tower pre-scrubber is used to remove sulfur compounds from the batch NCG streams (Batch Digesting System), and a separate spray tower pre-scrubber is used to remove sulfur compounds from the continuous NCG streams (Multiple Effect Evaporator System) prior to incineration in the boiler. The NCGs from the Turpentine Condensing System, the SOGs from the Condensate Stripper System, and the DNCGs are vented directly to the No. 4 Combination Boiler for incineration. The boiler is permitted to operate as the backup incineration device for the NCGs/SOGs for a maximum uptime of 20 percent on an annual basis.

PM emissions from the No. 4 Combination Boiler are controlled by a mechanical dust collector followed by an ESP. The Title V permit for the No. 4 Combination Boiler allows the following emission rates:

- PM
  - 0.3 pound per million British thermal units (lb/MMBtu), 125.6 pounds per hour (lb/hr), and 550.1 tons per year (TPY), when firing carbonaceous fuel only
  - 0.1 lb/MMBtu, 41.9 lb/hr, and 183.5 TPY, when firing No. 6 fuel oil (alone or blended with on-specification used oil) only
- Total Reduced Sulfur (TRS) – 5 parts per million by volume, dry, corrected to 10 percent oxygen (ppmvd @ 10% O_2) when burning DNCGs, NCGs, and/or SOGs; 3.6 lb/hr and 15.7 TPY
- Sulfur dioxide (SO_2)
  - 1,701.9 lb/hr and 1,767.8 TPY based on limiting the fuel oil sulfur content to 2.35 percent by weight.
  - Includes SO_2 emissions due to DNCG burning of 82.6 lb/hr and 236.6 TPY. The 236.6 TPY limit is a combined total for both the No. 4 Combination Boiler and the No. 5 Power Boiler (EU 015).
  - Includes additional SO_2 emissions due to NCG and SOG burning of 626.4 lb/hr and 548.7 TPY.

The No. 4 Combination Boiler was originally constructed in 1965, with the primary dust collector, and the boiler itself has not undergone any fundamental change since that time. Secondary and tertiary dust collection systems were added in 1975 and the ESP was constructed in 1986 to complete the particulate controls as they currently exist.

2.2 Proposed Operations

In this application, GP is proposing to implement three changes to the No. 4 Combination Boiler:

1. Replace the current No. 6 fuel oil burners in the No. 4 Combination Boiler with natural gas burners
2. Perform upgrades on the existing mechanical dust collectors serving the No. 4 Combination Boiler to improve reliability and reduce operating costs
3. Replace the steam turbine-driven ID fan on the No. 4 Combination Boiler with an electric motor and high-efficiency fan

2.2.1 Natural Gas Burners

GP is requesting the authorization to replace the current No. 6 fuel oil burners in the No. 4 Combination Boiler with natural gas burners. The maximum design heat input rate of the new burners will be 427 MMBtu/hr.

On February 15, 2010, the Palatka Mill received a Request for Additional Information (RAI) from FDEP related to Permit No. 1070005-045-AC/PSD-FL-393, which was issued to the Mill on September 26, 2008, and which authorized a two-phased construction project on the No. 4 Combination Boiler. Phase I of the No. 4 Combination Boiler project involved various modifications to increase the bark feed rate to the boiler. Phase II of the project was to convert the supplemental No. 6 fuel oil firing system on the boiler to natural gas and discontinue the use of No. 6 fuel oil in the No. 4 Combination Boiler.

Since issuance of the PSD construction permit in September 2008, the Phase I modifications have been cancelled in their entirety.[1] However, because the SO_2 emission reductions to be realized in Phase II of the project were relied upon in the Mill's BART exemption modeling demonstration initially submitted on January 31, 2007, and most recently updated on May 20, 2009, the discontinuation of No. 6 fuel oil firing in the No. 4 Combination Boiler is required. GP is therefore requesting that the existing permit (Permit No. 1070005-045-AC/PSD-FL-393) related to the No. 4 Combination Boiler be surrendered. The Phase II project will now become the subject of this new application for the No. 4 Combination Boiler.

2.2.2 Mechanical Dust Collector Rebuild

GP is also requesting in this application the authorization to rebuild the mechanical dust collector system in the No. 4 Combination Boiler. The system was originally designed and installed as a single mechanical

[1] Note that some portion of the Phase I projects may be required for the boiler to comply with the upcoming Maximum Achievable Control Technology (MACT) standards for industrial boilers (i.e., Boiler MACT). However, since the final Boiler MACT rule has not yet been released, there is no final compliance plan in place for the Mill.

cyclone dust collector. However, due to erosion of the ID fan and changes in environmental regulations, secondary and tertiary mechanical cyclone dust collection systems were added in 1975. These systems were designed with small 9-inch diameter cyclones. Over time the components inside the cyclones have experienced significant wear and erosion due to the high flue gas velocity and ash/sand content in the flue gas, which has resulted in significant costs to maintain the integrity of the system

GP is proposing to perform the following activities on the existing dust collector system:

- Replace the 9-inch diameter cyclones in the tertiary dust collector with 24-inch cyclones. The larger diameter cyclones will be more efficient and require a lower pressure drop to operate (approximately 3 inches of water column).
- Remove the internal structures in the primary and secondary dust collectors and convert them to simple gas ducts.

The rebuilt dust collector system will have lower maintenance costs, and will reduce energy usage due to a lower pressure drop design, which reduces required ID fan horsepower. The PM removal efficiency for the modified dust collector system will be approximately 84 percent (based on vendor guarantees), which is slightly greater than the current removal efficiency of 82 percent (based on stack testing). Therefore, the upgrade of the PM control equipment will not result in an increase in emissions from the No. 4 Combination Boiler, but may reduce PM emissions slightly. The vendor specifications for the upgraded dust collector are included in Appendix B.

2.2.3 Steam Turbine-Driven ID Fan

Lastly, GP is proposing to replace the steam turbine-driven ID fan-drive on the No. 4 Combination Boiler with an electric motor and replace the existing fan wheel with a high efficiency unit of the same flow capacity. The existing steam turbine-drive has experienced maintenance outages over the last several years, resulting in lost operation of the boiler. Replacing the fan-drive with an electric motor drive in combination with the dust collector project will result in a restoration of approximately 35 TPD of bark combustion in the No. 4 Combination Boiler that has been lost due to inefficient operation or maintenance related issues. The replacement fan wheel should result in energy savings, and will not increase flow capacity.

3.0 AIR QUALITY REVIEW REQUIREMENTS

3.1 PSD Review Requirements

The Palatka Mill is located in an area of Florida that is in attainment with the National Ambient Air Quality Standards (NAAQS) for all regulated pollutants. Therefore, the proposed project is being evaluated under the PSD portion of the NSR permitting program. A PSD review is used to determine whether significant air quality deterioration will result from a new major facility or a major modification at an existing facility. The Palatka Mill is an existing major stationary source because potential emissions of at least one PSD-regulated pollutant exceed 100 TPY [for example, potential nitrogen oxides (NO_x) 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 rate (SER).

Federal PSD requirements are contained in Title 40, Part 52.21 of the Code of Federal Regulations (40 CFR 52.21), Prevention of Significant Deterioration of Air Quality. FDEP has adopted PSD regulations that are equivalent to the federal PSD regulations (Rule 62-212.400, F.A.C.). For an existing major stationary source for which a modification is proposed, the modification is subject to PSD review if it causes two types of emissions increases – a significant emissions increase and a significant net emissions increase. In the first step, emissions increases from the project itself are computed and compared to the PSD SERs. If the increases are less than those levels, then no further analysis is necessary and PSD permitting is not required. If the increases for the project itself exceed those levels, then the second step involves additional analysis to determine if there will be a significant net emissions increase. The relevant PSD SERs are listed in Table 3-1.

The determination of whether a significant emissions increase will occur is based on comparison of "baseline actual emissions" to "projected actual emissions" for all emissions units affected by the proposed project. "Baseline actual emissions" and "projected actual emissions" are defined in Rules 62-210.200(36) and (244), F.A.C. "Baseline actual emissions" for an existing emissions unit, other than an electric utility steam generating unit, is the average rate, in TPY, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period, selected by the owner/operator, within the 10-year period immediately preceding the date a complete permit application is received by FDEP. The average rate includes fugitive emissions to the extent quantifiable and emissions associated with startups and shutdowns. The average rate must be adjusted downward to exclude:

- Any non-compliant emissions that occurred while the emissions units were operating above an emissions limitation that was legally enforceable during the consecutive 24-month period
- Any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitation during the consecutive 24-month period

For projects involving multiple emissions units, only one consecutive 24-month period can be used for all the emissions units being modified. However, a different 24-month period can be used for each PSD pollutant.

Rule 62-210.370, F.A.C., establishes the methodology for computing baseline actual emissions and net emissions increases. In general, this rule sets forth a hierarchy of emission estimating methods, of which the most accurate method is to be used. Continuous emission monitoring systems (CEMS) are generally recognized as the most accurate method, followed by mass balance calculations, followed by emission factors. If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid tests conducted during at least a 5-year period encompassing the period over which the emissions are computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

"Projected actual emissions" is the maximum annual rate, in TPY, at which an existing emissions unit is projected to emit a regulated air pollutant in any one of the 5 years following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's potential to emit that regulated air pollutant, and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the facility.

In determining the projected actual emissions, the source must consider all relevant information, including historical operating data, the company's own representations, the company's expected business activity, the company's filings with the state or federal regulatory authorities, and compliance plans or orders. Fugitive emissions, to the extent quantifiable, and emissions associated with startups and shutdowns must be considered.

The projected actual emissions shall exclude that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions, and that are also unrelated to the particular project, including any increased utilization due to demand growth (this is referred to as the "demand growth exclusion"). The preamble to the U.S. Environmental Protection Agency's (EPA's) final PSD rule revisions, promulgated on December 31, 2002, states:

> *That is, under today's new provisions for non-routine physical or operational changes to existing emissions units, rather than basing a unit's post-change emissions on its PTE, you may project an annual rate, in TPY, that reflects the maximum annual emissions rate that will occur during any one of the 5 years immediately after the physical or operational change. ...This projection of the unit's annual emissions rate following the change is defined as the "projected actual emissions", and will be based on your maximum annual rate in tons per year at which you are projected to emit a regulated NSR pollutant, less any amount of emissions that could have been accommodated during the selected 24 month baseline period and is not related to the change. Accordingly, you will calculate the unit's projected actual emissions as the product of: (1) The hourly emissions rate,*

which is based on the operational capabilities following the change(s), taking into account legally enforceable restrictions that could affect the hourly emissions rate following the change(s); and (2) the projected level of utilization, which is based on both the emissions unit's historical annual utilization rate and available information regarding the emissions units' likely post-change capacity utilization. ...From the initial calculation, you may then make the appropriate adjustment to subtract out any portion of the emissions increase that could have been accommodated during the unit's 24-month baseline period and is unrelated to the change. [Federal Register, Vol. 67, pg. 80196]

Consequently, under today's new rules, when a projected increase in equipment utilization is in response to a factor such as the growth in market demand, you may subtract the emission increases from the unit's projected actual emissions if: (1) The unit could have achieved the necessary level of utilization during the consecutive 24-month period you selected to establish the baseline actual emission; and (2) the increase is not related to the physical or operational change(s) made to the unit. [Federal Register, Vol. 67, pg. 80203]

Further explanation was provided in the preamble to EPA's proposed PSD rule revisions on September 14, 2006:

That is, the source can emit up to its current maximum capacity without triggering major NSR under the actual-to-projected-actual test, as long as the increase is unrelated to the change. [Federal Register, Vol. 71, pg. 54237]

Post-change emissions are generally projected using the emissions unit's maximum annual rate, in tons per year, at which it is expected to emit a regulated NSR pollutant within 5 years following a change, less any amount of emissions that the unit could have accommodated during the selected 24-month baseline period and that are unrelated to the change. This final "projected actual" value, in tons per year, is the value you compare to the "baseline actual emissions" to determine...whether the proposed project will result in a "significant" emissions increase, as defined in the first step of the calculation. [Federal Register, Vol. 71, pg. 54238]

If the project results in a significant emissions increase for any PSD pollutant, then all contemporaneous increases or decreases in emissions of that pollutant that have occurred at the facility in the last 5 years must also be considered to determine if a significant net emissions increase has occurred.

A PSD applicability analysis was conducted to demonstrate that the proposed GP Palatka project would not trigger PSD review. The analysis is presented in Section 4.0.

3.2 NSPS and NESHAPs Applicability

The No. 4 Combination Boiler is not currently subject to New Source Performance Standards (NSPS) Subpart Db (40 CFR 60, Subpart Db) for industrial, commercial, or institutional steam generating units. An existing source can become subject to the NSPS if it is "modified" or "reconstructed." Modification under NSPS is any physical change or change in the method of operation that causes an increase in any pollutant regulated under the NSPS, on a lb/hr basis. The replacement of the No. 6 fuel oil burners with natural gas burners in the No. 4 Combination Boiler will not cause an increase in emissions of any

NSPS-regulated pollutant on a lb/hr basis. The emission factors for PM, SO_2, and NO_x on a lb/MMBtu basis for bark/wood, No. 6 fuel oil, and natural gas combustion (from Tables 4-1 and 4-7) are:

- PM
  - Bark/Wood: 0.075 lb/MMBtu
  - No. 6 Fuel Oil: 0.038 lb/MMBtu
  - Natural Gas: 0.0076 lb/MMBtu
- SO_2
  - Bark/Wood: 0.025 lb/MMBtu
  - No. 6 Fuel Oil: 2.679 lb/MMBtu
  - Natural Gas: 0.0006 lb/MMBtu
- NO_x
  - Bark/Wood: 0.22 lb/MMBtu
  - No. 6 Fuel Oil: 0.313 lb/MMBtu
  - Natural Gas: 0.15 lb/MMBtu

Natural gas has lower emission factors for all pollutants compared to bark/wood or No. 6 fuel oil.

In order to determine hourly mass emission rates of NSPS pollutants for the No. 4 Combination Boiler, prior to the proposed change, the highest bark/wood and No. 6 fuel oil burning days during the baseline period were determined from information previously submitted to the FDEP. In the application for Permit No. 1070005-045-AC/PSD-FL-393 for the No. 4 Combination Boiler, the highest bark/wood burning day was determined to be March 11, 2004, and the highest No. 6 fuel oil burning day was determined to be March 14, 2003. On these days, the 24-hour average heat input rates were as follows:

- March 11, 2004: 423.90 MMBtu/hr from bark/wood; 31.96 MMBtu/hr from No. 6 fuel oil; 455.86 MMBtu/hr total
- March 14, 2003: 27.73 MMBtu/hr from bark/wood; 345.51 MMBtu/hr from No. 6 fuel oil; 373.24 MMBtu/hr total

The actual emission rates on a lb/hr basis before the proposed change are shown in Table 3-2. The heat input rates used before the change were based on the fuel firing scenario that produced the highest total hourly emissions for each pollutant.

In order to determine hourly mass emission rates of NSPS pollutants for the No. 4 Combination Boiler after the proposed change, the same heat input scenarios (days) were utilized, since the natural gas burner project will not affect the heat input to the boiler. The purpose of the project is for natural gas to replace fuel oil as the backup/alternative fuel for the No. 4 Combination Boiler, and the normal operation of the boiler will not change. Therefore, fuel oil firing was replaced by natural gas firing for the two scenarios shown in Table 3-2. As shown, the burning of natural gas will result in lower hourly emissions of SO_2, and NO_x, and PM.

Reconstruction under NSPS is any modification where the cost greater than 50-percent of the cost of constructing a new emissions unit. The proposed modifications to the No. 4 Combination Boiler are estimated to cost approximately $8.3 million. The cost of a new combination boiler of the same size is estimated at $100 million. Therefore, the cost of the proposed modifications are less than 10-percent of the cost of replacing the No. 4 Combination Boiler, and the No. 4 Combination Boiler will not constitute "reconstruction."

Based on the above analysis of emissions to the atmosphere and costs of the proposed project, the No. 4 Combination Boiler will not be subject to the NSPS Subpart Db due to the proposed project.

EPA is currently in the process of developing National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for the category of industrial, commercial, and institutional boilers and process heaters (Industrial Boiler MACT). The new standards are expected to be finalized by EPA in January 2011. The No. 4 Combination Boiler will be subject to the new NESHAPs, but a firm compliance strategy will not be developed by GP until the new standards are known.

4.0 AIR EMISSIONS

4.1 Baseline Actual Emissions

The methodology used to determine baseline actual emissions for the No. 4 Combination Boiler and the results of the determination are presented in this section. Based on Florida's PSD rules, the baseline actual emissions may be based on any consecutive 24-month period out of the last 10 years prior to submitting a complete application. Since complete data are not yet available for 2010, the baseline actual emissions were calculated based on a consecutive 24-month period out of the previous 9 years (2001-2009). Actual emissions for each of these years were determined based on operating data, available stack test data, and emission factors. For each pollutant, the consecutive 2-year period with the highest average annual (TPY) emissions was selected as the baseline actual emissions for the No. 4 Combination Boiler. The 2-year periods used for each pollutant are as follows:

Pollutant	2-Year Average Baseline
Sulfur Dioxide – SO_2	2004 to 2005
Nitrogen Oxides – NO_x	2002 to 2003
Carbon Monoxide – CO	2002 to 2003
Particulate Matter – PM	2002 to 2003
Particulate Matter under 10 microns in diameter – PM_{10}	2002 to 2003
Particulate Matter under 2.5 microns in diameter – $PM_{2.5}$	2002 to 2003
Volatile Organic Compounds – VOCs	2002 to 2003
Sulfuric Acid Mist – SAM	2004 to 2005
Lead – Pb	2002 to 2003
Mercury – Hg	2002 to 2003
Fluoride – F	2004 to 2005

The baseline actual emissions for the No. 4 Combination Boiler may differ from the annual emissions shown in the Annual Operating Reports (AORs) submitted to FDEP by GP, as described below.

The emission factors used for determining the baseline actual emissions are shown in Table 4-1. The Florida rules require that, if stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid tests conducted during at least a 5-year period encompassing the period over which the emissions are computed, provided all stack tests used represent the same operational and physical configuration of the unit. To determine the operational and physical configuration of the No. 4 Combination Boiler for each year during the past 10 years, the permitting files were researched. It was concluded that the No. 4 Combination Boiler has had the same operational/physical configuration over all the years for which stack tests are used to determine the baseline emissions (2000 through 2009). Stack test data for the No. 4 Combination Boiler used to determine baseline actual emissions are presented in Table 4-2.

The resulting baseline actual emissions for each pollutant for each year, based on the revised emission factors, are presented in Tables 4-4 through 4-6. The highest 2-year average for each pollutant represents the baseline actual emissions (see Table 4-6). The following sections describe in more detail the development of the baseline actual emission factors for each PSD pollutant.

4.1.1 Sulfur Dioxide

No. 6 Fuel Oil Combustion – Baseline actual SO_2 emissions for No. 6 fuel oil combustion were calculated from an emission factor of 0.164(S) pound per gallon of No. 6 fuel oil from Permit No. 1070005-064-AV, Specific Condition C.16, where S is the sulfur content (percent by weight) of the fuel. The emission factor was divided by the heating value for No. 6 fuel oil of 150,000 British thermal units per gallon (Btu/gal) to calculate a lb/MMBtu emission factor (see Table 4-1).

Bark/Wood Combustion – Baseline actual SO_2 emissions for bark/wood combustion were calculated from an emission factor of 0.025 lb/MMBtu from National Council for Air and Stream Improvement (NCASI) Technical Bulletin No. 884, Table 9.6a (see Table 4-1).

Total Annual Emissions – The annual heat input to the No. 4 Combination Boiler was determined using fuel heating values of 150,000 Btu/gal for No. 6 fuel oil and 4,500 British thermal units per pound (Btu/lb) of wet wood along with the annual fuel combustion amounts. Using the annual heat input rates to the No. 4 Combination Boiler for each year and the emission factors described above, the annual SO_2 emissions were calculated (see Table 4-4). The highest 2-year annual average SO_2 emissions were then calculated (see Table 4-5) and the highest 2-year average SO_2 emissions were selected as the baseline actual emissions (see Table 4-6).

4.1.2 Nitrogen Oxides

No. 6 Fuel Oil Combustion – Baseline actual NO_x emissions for No. 6 fuel oil combustion were calculated from an emission factor of 47 pounds per thousand gallons (lb/10^3 gal) of No. 6 fuel oil from AP-42, Table 1.3-1. The emission factor was divided by the heating value for No. 6 fuel oil of 150,000 Btu/gal to calculate a lb/MMBtu emission factor (0.313 lb/MMBtu; see Table 4-1).

Bark/Wood Combustion – Baseline actual NO_x emissions for bark/wood combustion were calculated from an emission factor of 0.22 lb/MMBtu from AP-42, Table 1.6-2 (see Table 4-1).

Total Annual Emissions – The annual heat input to the No. 4 Combination Boiler was determined using fuel heating values of 150,000 Btu/gal for No. 6 fuel oil and 4,500 Btu/lb of wet wood along with the annual fuel combustion amounts. Using the annual heat input rates to the No. 4 Combination Boiler for each year and the emission factors described above, the annual NO_x emissions were calculated (see Table 4-4). The highest 2-year annual average NO_x emissions were then calculated (see Table 4-5) and the highest 2-year average NO_x emissions were selected as the baseline actual emissions (see Table 4-6).

4.1.3 Carbon Monoxide

No. 6 Fuel Oil Combustion – Baseline actual CO emissions for No. 6 fuel oil combustion were calculated from an emission factor of 5 lb/10^3 gal of No. 6 fuel oil from AP-42, Table 1.3-1. The emission factor was divided by the heating value for No. 6 fuel oil of 150,000 Btu/gal to calculate a lb/MMBtu emission factor (0.033 lb/MMBtu; see Table 4-1).

Bark/Wood Combustion – Baseline actual CO emissions for bark/wood combustion were calculated from an emission factor of 0.6 lb/MMBtu from NCASI Technical Bulletin No. 884, Table 9.6a (see Table 4-1).

Total Annual Emissions – The annual heat input to the No. 4 Combination Boiler was determined using fuel heating values of 150,000 Btu/gal for No. 6 fuel oil and 4,500 Btu/lb of wet wood along with the annual fuel combustion amounts. Using the annual heat input rates to the No. 4 Combination Boiler for each year and the emission factors described above, the annual CO emissions were calculated (see Table 4-4). The highest 2-year annual average CO emissions were then calculated (see Table 4-5) and the highest 2-year average CO emissions were selected as the baseline actual emissions (see Table 4-6).

4.1.4 PM/PM_{10}/$PM_{2.5}$

No. 6 Fuel Oil Combustion – Three compliance tests were performed in 2003, 2004, and 2005 when only No. 6 fuel oil was burned in the No. 4 Combination Boiler. An average emission factor of 0.038 lb/MMBtu for No. 6 fuel oil firing only was determined from these compliance tests.

Filterable PM_{10} and $PM_{2.5}$ emission factors were 63 percent and 41 percent of PM emissions, respectively. These emission factors are based on AP-42, Table 1.3-4 for combustion of No. 6 fuel oil with ESP control (see Table 4-1).

The emission factor used for condensable PM, PM_{10} and $PM_{2.5}$ was 1.5 lb/10^3 gal based on AP-42, Table 1.3-2. The emission factor was divided by the heating value for No. 6 fuel oil of 150,000 Btu/gal to calculate a lb/MMBtu emission factor (0.010 lb/MMBtu; see Table 4-1).

Bark/Wood Combustion – Baseline actual PM emissions were calculated based on annual PM compliance test data (see Table 4-2). The compliance test averages, in lb/MMBtu, were determined for each year. Both No. 6 fuel oil and bark/wood were burned during these annual compliance tests, with the percentage of heat input to the No. 4 Combination Boiler during the test from each fuel also determined. The average emission factor in lb/MMBtu from the three compliance tests for No. 6 fuel oil combustion only (0.038 lb/MMBtu) was subtracted from the total lb/MMBtu emission factor during each of the annual compliance tests to determine a lb/MMBtu emission factor for bark/wood firing alone. An overall average emission factor was then determined from the annual lb/MMBtu emission factors from 2000 through 2009 (0.075 lb/MMBtu; see Table 4-2).

Filterable PM_{10} and $PM_{2.5}$ emission factors were 74 percent and 65 percent of PM emissions, respectively. These emission factors are based on NCASI Technical Bulletin No. 884, Table 9.6b for PM from wood combustion units with ESP control (see Table 4-1). The emission factor used for condensable PM, PM_{10} and $PM_{2.5}$ was 0.017 lb/MMBtu based on AP-42, Table 1.6-1.

Total Emissions – The annual heat input to the No. 4 Combination Boiler was determined using fuel heating values of 150,000 Btu/gal for No. 6 fuel oil and 4,500 Btu/lb of wet wood along with the annual fuel combustion amounts. Using the annual heat input rates to the No. 4 Combination Boiler for each year and the emission factors described above, the annual $PM/PM_{10}/PM_{2.5}$ emissions were calculated (see Table 4-4). The annual $PM/PM_{10}/PM_{2.5}$ emissions were calculated from the sum of the filterable and condensable emission factors. The highest 2-year annual average $PM/PM_{10}/PM_{2.5}$ emissions were then calculated (see Table 4-5) and the highest 2-year average $PM/PM_{10}/PM_{2.5}$ emissions were selected as the baseline actual emissions (see Table 4-6).

4.1.5 Volatile Organic Compounds

No. 6 Fuel Oil Combustion – Baseline actual VOC emissions for No. 6 fuel oil combustion were calculated from an emission factor of 0.28 lb/10^3 gal of No. 6 fuel oil from AP-42, Table 1.3-3. The emission factor was divided by the heating value for No. 6 fuel oil of 150,000 Btu/gal to calculate a lb/MMBtu emission factor (0.0019 lb/MMBtu; see Table 4-1).

Bark/Wood Combustion – Baseline actual VOC emissions for bark/wood combustion were calculated from an emission factor of 0.034 lb/MMBtu from NCASI Technical Bulletin No. 884, Table 9.6a (see Table 4-1).

Total Emissions – The annual heat input to the No. 4 Combination Boiler was determined using fuel heating values of 150,000 Btu/gal for No. 6 fuel oil and 4,500 Btu/lb of wet wood along with the annual fuel combustion amounts. Using the annual heat input rates to the No. 4 Combination Boiler for each year and the emission factors described above, the annual VOC emissions were calculated (see Table 4-4). The highest 2-year annual average VOC emissions were then calculated (see Table 4-5) and the highest 2-year average VOC emissions were selected as the baseline actual emissions (see Table 4-6).

4.1.6 Total Reduced Sulfur

The No. 4 Combination Boiler is designated as the backup control device for DNCGs, NCGs, and SOGs. Emissions of TRS are only expected when the No. 4 Combination Boiler is acting as the control device for these gases. The replacement of the No. 6 fuel oil burner in the No. 4 Combination Boiler will not affect TRS or SO_2 emissions resulting from the destruction of these gases, nor will the replacement affect how the No. 4 Combination Boiler is used as a backup control device for these gases. Therefore, TRS emissions due to DNCG, NCG, or SOG destruction were not included in the PSD applicability analysis.

4.1.7 Sulfuric Acid Mist

SAM emissions can be estimated from a method similar to fuel oil combustion where the ratio of sulfur trioxide (SO_3) to SO_2 emissions from AP-42, Table 1.3-1 (5.7/157) is used, and then multiplied by the ratio of the molecular weight of sulfuric acid (H_2SO_4) to SO_3 (98/80). The resulting SAM emission factor is approximately 4.45 percent of the SO_2 emission factor (Table 4-1).

Using the annual SO_2 emission factors for No. 6 fuel oil firing and bark/wood firing and the 4.45 percent factor, the annual SAM emissions for each year were determined (see Table 4-4). The highest 2-year annual average SAM emissions were then calculated (see Table 4-5) and the highest 2-year average SAM emissions were selected as the baseline actual emissions (see Table 4-6).

4.1.8 Lead

No. 6 Fuel Oil Combustion – Baseline actual Pb emissions for No. 6 fuel oil combustion were calculated from an emission factor of 0.00151 lb/10^3 gal of No. 6 fuel oil from AP-42, Table 1.3-11. The emission factor was divided by the heating value for No. 6 fuel oil of 150,000 Btu/gal to calculate a lb/MMBtu emission factor (1.01×10^{-5} lb/MMBtu; see Table 4-1).

Bark/Wood Combustion – Baseline actual Pb emissions for bark/wood combustion were calculated from an emission factor of 4.95×10^{-6} lb/MMBtu from NCASI Technical Bulletin 973, Table 7.2 (see Table 4-1).

Total Emissions – The annual heat input to the No. 4 Combination Boiler was determined using fuel heating values of 150,000 Btu/gal for No. 6 fuel oil and 4,500 Btu/lb of wet wood along with the annual fuel combustion amounts. Using the annual heat input rates to the No. 4 Combination Boiler for each year and the emission factors described above, the annual Pb emissions were calculated (see Table 4-4). The highest 2-year annual average Pb emissions were then calculated (see Table 4-5) and the highest 2-year average Pb emissions were selected as the baseline actual emissions (see Table 4-6).

4.1.9 Mercury

No. 6 Fuel Oil Combustion – Baseline actual Hg emissions for No. 6 fuel oil combustion were calculated from an emission factor of 0.000113 lb/10^3 gal of No. 6 fuel oil from AP-42, Table 1.3-11. The emission factor was divided by the heating value for No. 6 fuel oil of 150,000 Btu/gal to calculate a lb/MMBtu emission factor (7.53×10^{-7} lb/MMBtu; see Table 4-1).

Bark/Wood Combustion – Baseline actual Hg emissions for bark/wood combustion were calculated from an emission factor of 5.73×10^{-7} lb/MMBtu from a stack test performed on May 18, 2010 (see Table 4-2).

Total Emissions – The annual heat input to the No. 4 Combination Boiler was determined using fuel heating values of 150,000 Btu/gal for No. 6 fuel oil and 4,500 Btu/lb of wet wood along with the annual fuel combustion amounts. Using the annual heat input rates to the No. 4 Combination Boiler for each year and the emission factors described above, the annual Hg emissions were calculated (see Table 4-4). The highest 2-year annual average Hg emissions were then calculated (see Table 4-5) and the highest 2-year average Hg emissions were selected as the baseline actual emissions (see Table 4-6).

4.1.10 Fluoride

No. 6 Fuel Oil Combustion – Baseline actual F emissions for No. 6 fuel oil combustion were calculated from an emission factor of 0.0373 lb/10^3 gal of No. 6 fuel oil from AP-42, Table 1.3-11. The emission factor was divided by the heating value for No. 6 fuel oil of 150,000 Btu/gal to calculate a lb/MMBtu emission factor (0.00025 lb/MMBtu; see Table 4-1).

Bark/Wood Combustion – No emission factors exist for fluoride emissions from bark/wood combustion; therefore, no F emissions were determined (see Table 4-1).

Total Emissions – The annual heat input to the No. 4 Combination Boiler was determined using a fuel heating value of 150,000 Btu/gal for No. 6 fuel oil with the annual fuel combustion amounts. Using the annual heat input rates to the No. 4 Combination Boiler for each year and the emission factor described above, the annual F emissions were calculated (see Table 4-4). The highest 2-year annual average F emissions were then calculated (see Table 4-5) and the highest 2-year average F emissions were selected as the baseline actual emissions (see Table 4-6).

4.2 Projected Actual Emissions

"Projected actual emissions" for the No. 4 Combination Boiler were developed considering the Palatka Mill's projected future operation of the boiler. The emission factors used to calculate the projected actual emissions due to bark/wood combustion were the same as the baseline actual emission factors for all pollutants, except for NO_x. The projected NO_x emission factor is 0.25 lb/MMBtu, based on a conservative engineering estimate after the construction has been completed.

The emission factors used to calculate the projected actual emissions due to natural gas combustion are as follows:

- SO_2 – 0.0006 lb/MMBtu
- NO_x – 0.15 lb/MMBtu
- CO – 0.1 lb/MMBtu
- $PM/PM_{10}/PM_{2.5}$ – 0.0076 lb/MMBtu
- VOCs – 0.0055 lb/MMBtu
- SAM – 2.67×10^{-5} lb/MMBtu
- Pb – 5.00×10^{-7} lb/MMBtu
- Hg – 2.6×10^{-7} lb/MMBtu

The SO_2, $PM/PM_{10}/PM_{2.5}$, VOC, and Pb emission factors are based on AP-42, Table 1.4-2, and a natural gas heating value of 1,000 British thermal units per cubic foot (Btu/ft^3). The NO_x and CO emission factors are based on vendor estimates for natural gas firing. The SAM emission factor is based on the method described in Section 4.1.7, where approximately 4.45 percent of the SO_2 emissions become SAM. The Hg emission factor is based on AP-42, Table 1.4-4, and a natural gas heating value of 1,000 Btu/ft^3.

The operating factor used to calculate the bark/wood combustion portion of the projected actual emissions for the No. 4 Combination Boiler is based on the Mill's projections of maximum annual heat input to the boiler from bark/wood combustion over the next 5 years. The Palatka Mill estimates a maximum annual heat input rate due to bark/wood combustion to the No. 4 Combination Boiler of 2,992,500 million British thermal units per year (MMBtu/yr), which is based on a maximum annual bark/wood combustion rate of 315,000 TPY, and a heating value for wet wood of 4,750 Btu/lb.

Since natural gas will replace No. 6 fuel oil as the supplemental fuel to the boiler, the operating factor used for natural gas is equal to the historical maximum annual heat input rate due to fuel oil combustion in the No. 4 Combination Boiler (695,007 MMBtu/yr; see Table 4-3). The total projected annual heat input to the No. 4 Combination Boiler is therefore 3,687,507 MMBtu/yr.

4.3 Emissions That Could Have Been Accommodated

According to Florida PSD regulations, the definition of "projected actual emissions" states the following:

> *In determining the projected actual emissions, the Department:*
>
> *(c) Shall exclude that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are also unrelated to the particular project including any increased utilization due to product demand growth [Rule 62-210.200(244)(c), F.A.C.]*

To determine the emissions that the No. 4 Combination Boiler "could have accommodated" during the baseline period, the monthly heat input rate from bark/wood combustion was evaluated during the baseline period. Since No. 6 fuel oil will not be used in the future and is not included in the projected actual emissions estimates, no emissions associated with No. 6 fuel oil combustion are included when determining the level of emissions that the No. 4 Combination Boiler "could have accommodated" during the baseline period. No. 6 fuel oil emissions are only included in when determining baseline actual emissions. Similarly, since natural gas could not be used as a supplemental fuel in the past, no emissions associated with future natural gas combustion have been included in the "could have accommodated" emissions calculations, and all natural gas emissions are included in projected actual emissions.

As shown in Section 4.1, the baseline period was 2004 – 2005 for SO_2, SAM, and F, and 2002 – 2003 for all other pollutants. The monthly heat input to the boiler from bark/wood combustion during the baseline periods is shown in Table 4-8. These monthly heat input rates were divided by the number of days in each month and then by 24 hours per day to determine average hourly heat input rates as a monthly average. The highest monthly average hourly heat input rates for bark/wood combustion were:

- 2002 – 2003 Baseline: 390.26 MMBtu/hr
- 2004 – 2005 Baseline: 415.66 MMBtu/hr

The highest annual hours of operation during the baseline periods were:

- 2002 – 2003 Baseline: 8,302 hr/yr
- 2004 – 2005 Baseline: 8,425 hr/yr

The highest annual operating hours were used in combination with the highest monthly average hourly heat input rates from bark/wood combustion to determine the highest total annual heat input rate from bark/wood combustion that the No. 4 Combination Boiler could have accommodated during the baseline period. The resulting values are:

- 2002 – 2003 Baseline: 3,239,946 MMBtu/yr
- 2004 – 2005 Baseline: 3,501,937 MMBtu/yr

However, the calculation of the heat input rate that the No. 4 Combination Boiler could have accommodated from bark/wood combustion is greater than the Palatka Mill's projected heat input rate to the No. 4 Combination Boiler of 2,992,500 MMBtu/yr from bark/wood combustion. Therefore, GP is limiting its "could have accommodated" heat input rate from bark/wood combustion to no more than the projected heat input rate of 2,992,500 MMBtu/yr.

The supplemental burner replacement project will not affect bark/wood combustion in the boiler; therefore, these maximum annual bark/wood heat input rates are entirely unrelated to that project. The dust collector project and the replacement of the steam turbine-driven ID fan-drive with an electric motor are conservatively expected to restore approximately 35 TPD of bark/wood combustion. This restored operation is directly attributable to these proposed projects and, therefore, cannot be excluded from the projected actual emissions.

The heat input from bark/wood combustion restored from the dust collector/ID fan project is 111,825 MMBtu/yr. This heat input rate is based on assuming the restored bark/wood capacity is attained for 355 days per year. This restored heat input is subtracted from the projected annual heat input rate due to bark/wood combustion (2,992,500 MMBtu/yr) to determine the final "could have accommodated" heat input rate from bark/wood combustion in the No. 4 Combination Boiler of 2,880,675 MMBtu/yr (see Table 4-9).

GP believes this maximum annual heat input rate from bark/wood can be used as a conservative approximation of that portion of the No. 4 Combination Boiler's projected actual heat input rate that could have been accommodated during the 24-month baseline period, and could be accommodated in the future, separate and apart from the changes proposed in this application. As described above, the emissions from bark/wood combustion that could reasonably be attributed to the dust collector/ID fan replacement projects are excluded from the "could have accommodated" emissions, as those emissions are directly related to the proposed project.

The amount of emissions required to be excluded under the definition of "projected actual emissions" provided above is difficult to assess, and the rules contain no specific guidance. The rule does not say, and GP is not attempting to claim, that the full amount of a unit's permit-allowable emissions can be excluded. There are, for example, practical operating reasons why a unit cannot or does not emit at its full permit-allowable rate. However, the rule does not set any limits on the excludable amount; therefore, it is reasonable to state that the excludable amount is the level of emissions that could reasonably and legally have been accommodated by the unit during the 24-month baseline period, before (in the absence of) the particular project. The rules clearly do not limit this excludable amount to the amount actually emitted (i.e., the highest demonstrated/documented level of emissions) during the 24-month baseline period. Rather, the rules state that an applicant must exclude that portion of any projected emissions increase that the unit "could" have emitted during the 24-month baseline period, before implementation of the project (i.e., if its ability or reason to emit at that level in the future is not related to the project).

GP believes the No. 4 Combination Boiler could have accommodated a higher bark/wood heat input rate during the 24-month baseline period had there been a higher product demand resulting in a higher steam demand by the facility, and therefore more bark/wood fuel combustion and a higher annual heat input rate to the boiler. However, this 1-month period method is being used as a convenient and conservative measure because it can easily be documented that this level of bark/wood heat input, in fact, occurred and was accommodated by the existing equipment in the absence of any factor related to the proposed project. In addition, this methodology for determining "could have accommodated" emissions has been reviewed and approved by the EPA.[2]

It should also be noted that future market conditions, entirely unrelated to the burner replacement project, the dust collector project, or the steam turbine ID fan project, could result in additional product demand and, therefore, additional bark/wood fuel combustion and heat input to the boiler. As such, the GP Palatka Mill is not limited to the projected actual bark/wood heat input rate for the No. 4 Combination Boiler, which is based on the Mill's current best projections of the maximum amount of bark/wood that will

[2] Letter from Mr. Gregg Worley, Chief, Air Permits Section, Region 4, EPA to Mr. Mark Robinson, Plant Manager, Georgia-Pacific Wood Products LLC, dated March 18, 2010.

be combusted in the boiler. Similarly, the Palatka Mill is not limited to the high-monthly "could have accommodated" bark/wood heat input rate used in the PSD applicability analysis.

The annual "could have accommodated" heat input rate and the baseline emission factors were used to determine the annual emissions that could have been accommodated during the baseline period (see Table 4-9). As stated above, since the burner replacement will not affect the total annual bark/wood heat input rate, all "could have accommodated" bark/wood emissions are unrelated to the project and are excluded from projected actual emissions. No emissions associated with future combustion of natural gas have been excluded from projected actual emissions as these emissions are related to the proposed project.

4.4 Records of Excluded Emissions

According to Florida PSD regulations, each applicant for an air construction permit for an emissions unit subject to this (permitting) rule shall provide the Department, at a minimum, the following information:

> *"...the applicant shall also provide a record of the amount of excluded emissions, and an explanation as to why these emissions were excluded, for any projected actual emissions calculations that exclude that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are unrelated to the particular project including any increased utilization due to product demand growth." [Rule 62-212.300(3)(a)1., F.A.C.]*

Therefore, the FDEP rules require that the applicant identify any emissions that have been excluded from the projected actual emissions due to demand growth. The emissions that can be excluded from the PSD applicability analysis due to growth in demand for the No. 4 Combination Boiler, and not due to the project, are a subset of the "could have accommodated" emissions and are determined by subtracting the baseline actual emissions (see Table 4-6) from the "could have accommodated" emissions (see Table 4-9). The amount of excluded emissions is identified in Table 4-10.

4.5 Effects on Other Emissions Units

No other emissions units at the Palatka Mill are anticipated to be affected by this project. The purpose of the project is to allow the Palatka mill to burn natural gas instead No. 6 fuel oil in the No. 4 Combination Boiler, to comply with its BART exemption criteria, and to implement other changes.

4.6 PSD Review

The net increase in emissions due to the proposed bumer replacement project is summarized in Table 4-10. As shown, no emission increases exceed the PSD significant emissions rate. Therefore, PSD review does not apply to the proposed project.

TABLES

Table 3-1: PSD Significant Emission Rates and *De Minimis* Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration [a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Particulate Matter [PM(TSP)]	NSPS	25	NA
Particulate Matter (PM_{10})	NAAQS	15	10, 24-hour
Particulate Matter ($PM_{2.5}$) [b]	NAAQS	10, or	NA
	NAAQS	40 of SO_2, or	NA
	NAAQS	40 of NO_x	NA
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY [c]
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Sulfuric Acid Mist	NSPS	7	NM
Lead	NAAQS	0.6	0.1, 3-month
Mercury	NESHAP	0.1	0.25, 24-hour
Total Fluorides	NSPS	3	0.25, 24-hour

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

NA = not applicable

NM = no ambient measurement method established; therefore, no *de minimis* concentration has been established

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

[a] Short-term concentrations are not to be exceeded

[b] Any emission rate of these pollutants.

[c] No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more requires a monitoring analysis for ozone.

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

Table 3-2: Change in Hourly Emission Rates of NSPS-Regulated Pollutants
No. 4 Combination Boiler, Georgia-Pacific, Palatka

Pollutant	Emissions Before the Proposed Change: Emission Factor (lb/MMBtu) [a]	Emissions Before the Proposed Change: Activity Factor (MMBtu/hr) [b]	Emissions Before the Proposed Change: Hourly Emissions (lb/hr)	Emissions After the Proposed Change: Emission Factor (lb/MMBtu) [a]	Emissions After the Proposed Change: Activity Factor (MMBtu/hr) [b]	Emissions After the Proposed Change: Hourly Emissions (lb/hr)	Change in Hourly Emissions (lb/hr)
Sulfur Dioxide - SO_2							
-- *Bark*	0.025	27.73	0.69	0.025	423.90	10.60	
-- *No. 6 Fuel Oil*	2.679	345.51	925.51	--	--	--	
-- *Natural Gas*	--	--	--	0.0006	31.96	0.02	
-- Total	--	**373.24**	**926.21**	--	**455.86**	**10.62**	**-915.59**
Nitrogen Oxides - NO_x							
-- *Bark*	0.22	27.73	6.10	0.22	423.90	93.26	
-- *No. 6 Fuel Oil*	0.313	345.51	108.26	--	--	--	
-- *Natural Gas*	--	--	--	0.15	31.96	4.79	
-- Total	--	**373.24**	**114.36**	--	**455.86**	**98.05**	**-16.31**
Particulate Matter Total - PM							
-- *Bark*	0.075	423.90	31.73	0.075	423.90	31.73	
-- *No. 6 Fuel Oil*	0.038	31.96	1.20	--	--	--	
-- *Natural Gas*	--	--	--	0.0076	31.96	0.24	
-- Total	--	**455.86**	**32.93**	--	**455.86**	**31.97**	**-0.96**

[a] See Table 4-1 for emission factors for bark/wood and fuel oil combustion. See Table 4-7 for emission factors for natural gas combustion.
[b] Activity factors for bark/wood and fuel oil combustion based on the highest daily wood/bark and fuel oil burning days during the baseline period presented in the application for Permit No. 1070005-045-AC/PSD-FL-393. Activity factors for natural gas are given in Table 4-7.
Highest bark burning day - March 11, 2004: 423.90 MMBtu/hr from bark, 31.96 MMBtu/hr from fuel oil.
Highest fuel oil burning day - March 14, 2003: 27.73 MMBtu/hr from bark, 345.51 MMBtu/hr from fuel oil.
Heat input from natural gas replaces the heat input from fuel oil after the change.

Table 4-1: Emission Factors Used to Determine Baseline Actual Annual Emissions (2001 - 2009)
No. 4 Combination Boiler, Georgia-Pacific, Palatka

Source Description	Operating Hours (hr/yr)	Percent Sulfur (%)	Annual Process / Fuel Usage	Annual Heat Input (MMBtu) [A]	Pollutant Emission Factors (lb/MMBtu)											
					SO_2	NO_x	CO	Filterable PM	Filterable PM_{10}	Filterable $PM_{2.5}$	Condensable $PM/PM_{10}/PM_{2.5}$	VOC	SAM	Lead	Mercury	Fluoride
2001 Actual Emission Factors																
- No. 4 Combination Boiler (EU 016)	8,393															
- - No. 6 Fuel Oil		2.45	3,607.23 x 10^3 gal	541,085	2.679 [B]	0.313 [C]	0.033 [C]	0.038 [D]	0.024 [E]	0.015 [E]	0.010 [F]	0.0019 [G]	0.119 [H]	1.01E-05 [I]	7.53E-07 [I]	0.00025 [I]
- - Bark / Wood		--	278,240 tons	2,504,160	0.025 [J]	0.22 [K]	0.6 [J]	0.075 [D]	0.055 [L]	0.049 [L]	0.017 [M]	0.034 [J]	0.0011 [H]	4.95E-06 [N]	5.73E-07 [D]	--
2002 Actual Emission Factors																
- No. 4 Combination Boiler (EU 016)	8,109															
- - No. 6 Fuel Oil		2.27	4,429.473 x 10^3 gal	664,421	2.482 [B]	0.313 [C]	0.033 [C]	0.038 [D]	0.024 [E]	0.015 [E]	0.010 [F]	0.0019 [G]	0.110 [H]	1.01E-05 [I]	7.53E-07 [I]	0.00025 [I]
- - Bark / Wood		--	304,281 tons	2,738,529	0.025 [J]	0.22 [K]	0.6 [J]	0.075 [D]	0.055 [L]	0.049 [L]	0.017 [M]	0.034 [J]	0.0011 [H]	4.95E-06 [N]	5.73E-07 [D]	--
2003 Actual Emission Factors																
- No. 4 Combination Boiler (EU 016)	8,302															
- - No. 6 Fuel Oil		2.12	4,333.33 x 10^3 gal	650,000	2.318 [B]	0.313 [C]	0.033 [C]	0.038 [D]	0.024 [E]	0.015 [E]	0.010 [F]	0.0019 [G]	0.103 [H]	1.01E-05 [I]	7.53E-07 [I]	0.00025 [I]
- - Bark / Wood		--	293,274 tons	2,639,466	0.025 [J]	0.22 [K]	0.6 [J]	0.075 [D]	0.055 [L]	0.049 [L]	0.017 [M]	0.034 [J]	0.0011 [H]	4.95E-06 [N]	5.73E-07 [D]	--
2004 Actual Emission Factors																
- No. 4 Combination Boiler (EU 016)	8,425															
- - No. 6 Fuel Oil		2.14	4,351.657 x 10^3 gal	652,749	2.340 [B]	0.313 [C]	0.033 [C]	0.038 [D]	0.024 [E]	0.015 [E]	0.010 [F]	0.0019 [G]	0.104 [H]	1.01E-05 [I]	7.53E-07 [I]	0.00025 [I]
- - Bark / Wood		--	300,219 tons	2,701,971	0.025 [J]	0.22 [K]	0.6 [J]	0.075 [D]	0.055 [L]	0.049 [L]	0.017 [M]	0.034 [J]	0.0011 [H]	4.95E-06 [N]	5.73E-07 [D]	--
2005 Actual Emission Factors																
- No. 4 Combination Boiler (EU 016)	8,323															
- - No. 6 Fuel Oil		2.18	4,633.378 x 10^3 gal	695,007	2.383 [B]	0.313 [C]	0.033 [C]	0.038 [D]	0.024 [E]	0.015 [E]	0.010 [F]	0.0019 [G]	0.106 [H]	1.01E-05 [I]	7.53E-07 [I]	0.00025 [I]
- - Bark / Wood		--	269,420 tons	2,424,780	0.025 [J]	0.22 [K]	0.6 [J]	0.075 [D]	0.055 [L]	0.049 [L]	0.017 [M]	0.034 [J]	0.0011 [H]	4.95E-06 [N]	5.73E-07 [D]	--
2006 Actual Emission Factors																
- No. 4 Combination Boiler (EU 016)	8,265															
- - No. 6 Fuel Oil		2.17	4,215.837 x 10^3 gal	632,376	2.373 [B]	0.313 [C]	0.033 [C]	0.038 [D]	0.024 [E]	0.015 [E]	0.010 [F]	0.0019 [G]	0.106 [H]	1.01E-05 [I]	7.53E-07 [I]	0.00025 [I]
- - Bark / Wood		--	289,662 tons	2,606,958	0.025 [J]	0.22 [K]	0.6 [J]	0.075 [D]	0.055 [L]	0.049 [L]	0.017 [M]	0.034 [J]	0.0011 [H]	4.95E-06 [N]	5.73E-07 [D]	--
2007 Actual Emission Factors																
- No. 4 Combination Boiler (EU 016)	8,479															
- - No. 6 Fuel Oil		1.59	4,384.355 x 10^3 gal	657,653	1.738 [B]	0.313 [C]	0.033 [C]	0.038 [D]	0.024 [E]	0.015 [E]	0.010 [F]	0.0019 [G]	0.077 [H]	1.01E-05 [I]	7.53E-07 [I]	0.00025 [I]
- - Bark / Wood		--	295,712 tons	2,661,408	0.025 [J]	0.22 [K]	0.6 [J]	0.075 [D]	0.055 [L]	0.049 [L]	0.017 [M]	0.034 [J]	0.0011 [H]	4.95E-06 [N]	5.73E-07 [D]	--
2008 Actual Emission Factors																
- No. 4 Combination Boiler (EU 016)	8,092															
- - No. 6 Fuel Oil		1.61	3,850.642 x 10^3 gal	577,596	1.760 [B]	0.313 [C]	0.033 [C]	0.038 [D]	0.024 [E]	0.015 [E]	0.010 [F]	0.0019 [G]	0.078 [H]	1.01E-05 [I]	7.53E-07 [I]	0.00025 [I]
- - Bark / Wood		--	283,183 tons	2,548,647	0.025 [J]	0.22 [K]	0.6 [J]	0.075 [D]	0.055 [L]	0.049 [L]	0.017 [M]	0.034 [J]	0.0011 [H]	4.95E-06 [N]	5.73E-07 [D]	--
2009 Actual Emission Factors																
- No. 4 Combination Boiler (EU 016)	8,201															
- - No. 6 Fuel Oil		1.60	4,158.724 x 10^3 gal	623,809	1.749 [B]	0.313 [C]	0.033 [C]	0.038 [D]	0.024 [E]	0.015 [E]	0.010 [F]	0.0019 [G]	0.078 [H]	1.01E-05 [I]	7.53E-07 [I]	0.00025 [I]
- - Bark / Wood		--	256,310 tons	2,306,790	0.025 [J]	0.22 [K]	0.6 [J]	0.075 [D]	0.055 [L]	0.049 [L]	0.017 [M]	0.034 [J]	0.0011 [H]	4.95E-06 [N]	5.73E-07 [D]	--

[A] Heating values are as follows: No. 6 Fuel Oil: 150,000 Btu/gal; Bark: 4,500 Btu/lb (wet)

[B] Based on Permit No. 1070005-064-AV, Condition C.16. SO_2 emission factor is (0.164 x %S) lb/gal.

[C] AP-42, Table 1.3-1. Emission factors in lb/10^3 gal are: NO_x - 47, CO - 5.

[D] Based on past stack testing (see Table 4-2).

[E] AP-42, Table 1.3-4 for combustion of No. 6 fuel oil with ESP control. 63 percent of PM emissions are PM_{10}, 41 percent of PM emissions are $PM_{2.5}$.

[F] AP-42, Table 1.3-2, Condensable PM Emission Factors for Fuel Oil Combustion. Emission factor is 1.5 lb/10^3 gal.

[G] AP-42, Table 1.3-3. VOC emission factor is 0.28 lb/10^3 gal.

[H] Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3.63% of SO_2 becomes SO_3 then multiply by the ratio of H_2SO_4 and SO_3 molecular weights (98/80).

[I] AP-42, Table 1.3-11, uncontrolled emissions. Emission factors in lb/10^3 gal are: Pb - 0.00151, Hg - 0.000113, F - 0.0373.

[J] NCASI Technical Bulletin No. 884, Table 9.6a. Uncontrolled emissions from wood combustion units.

[K] Based on AP-42, Table 1.6-2, for bark/bark and wet wood/wet wood-fired boilers.

[L] NCASI Technical Bulletin No. 884, Table 9.6b, PM emissions from wood combustion units with ESP control. PM_{10} and $PM_{2.5}$ emissions are 74 percent and 65 percent of PM emissions, respectively.

[M] AP-42, Table 1.6-1, Emission Factors for PM from Wood Residue Combustion.

[N] NCASI Technical Bulletin No. 973, Table 7.2, Summary of Trace Metal Emissions from Wood-Fired Boilers with ESP control, median value.

Table 4-2: No. 4 Combination Boiler Stack Tests and Emissions Data
Georgia-Pacific, Palatka

Test Date	Heat Input Rate (MMBtu/hr)	Emission Rate [a] (lb/hr)	Emission Rate [a] (lb/MMBtu)	Bark/Wood Firing Percent of Heat Input	Bark/Wood Firing Heat Input (MMBtu/hr)	Fuel Oil Firing Percent of Heat Input	Fuel Oil Firing Heat Input (MMBtu/hr)	Emissions Contributions by Individual Fuels: Fuel Oil Portion (lb/hr) [b]	Emissions Contributions by Individual Fuels: Bark/Wood Portion (lb/hr) [c]	Emissions Contributions by Individual Fuels: Bark/Wood Factor (lb/MMBtu) [d]
PM Emissions										
- Bark/Wood & Fuel Oil Firing										
4/18/2000	432.44	43.77	0.101	75%	324.33	25%	108.11	4.06	39.71	0.122
7/18/2001	393.39	15.77	0.040	66%	258.85	34%	134.54	5.05	10.72	0.041
6/19/2002	414.64	19.73	0.048	66%	273.25	34%	141.39	5.31	14.42	0.053
1/8/2003	445.97	26.42	0.059	77%	342.51	23%	103.47	3.88	22.54	0.066
1/8/2004	448.83	39.13	0.087	78%	352.11	22%	96.72	3.63	35.50	0.101
8/18/2005	482.67	19.30	0.040	69%	333.04	31%	149.63	5.62	13.68	0.041
4/24/2006	503.80	17.09	0.034	80%	403.04	20%	100.76	3.78	13.30	0.033
9/25/2007	465.15	26.96	0.058	75%	348.86	25%	116.29	4.37	22.60	0.065
5/21/2008	466.07	60.57	0.130	85%	396.16	15%	69.91	2.62	57.95	0.146
6/25/2009	375.22	27.67	0.074	85%	318.93	15%	56.28	2.11	25.56	0.080
									Average:	0.075
- Fuel Oil Firing Only										
1/7/2003	424.73	13.86	0.033	--	--	--	--	--	--	--
1/8/2004	420.00	12.60	0.030	--	--	--	--	--	--	--
8/22/2005	350.00	17.5	0.050	--	--	--	--	--	--	--
			0.038							
Hg Emissions										
5/18/2010	390.43	2.2E-04	5.73E-07							

[a] Maximum permitted PM emission rate is 0.3 lb/MMBtu when firing only carbonaceous fuel, 0.1 lb/MMBtu when firing fuel oil only, and a ratio of the two limits when firing both fuels (based on the ratio of the heat input rates of the two fuels).

[b] Average PM emission factor from 100% fuel oil firing (0.038 lb/MMBtu) multiplied by the heat input rate from fuel oil firing (MMBtu/hr) during that stack test.

[c] Calculated from the difference between the total emissions during the stack test (lb/hr) and the emissions from fuel oil firing (lb/hr).

[d] Calculated from the emissions from bark/wood firing only (lb/hr) divided by the heat input from bark/wood firing during the stack test (MMBtu/hr).

Table 4-3: Baseline Actual Annual (2001 - 2009) Operating Conditions
No. 4 Combination Boiler, Georgia-Pacific, Palatka

		Fuel Usage							
	Operating	Bark	No. 6 Fuel Oil		Heat Input (MMBtu/yr) [a]			Heat Input (%)	
Test Date	Hours (hr/yr)	Usage (TPY, wet)	Usage (gal/yr)	Heat Input (% Sulfur)	From Bark	From Fuel Oil	Total	From Bark	From Fuel Oil
2001	8,393	278,240	3,607,230	2.45	2,504,160	541,085	3,045,245	82.23%	17.77%
2002	8,109	304,281	4,429,473	2.27	2,738,529	664,421	3,402,950	80.48%	19.52%
2003	8,302	293,274	4,333,330	2.12	2,639,466	650,000	3,289,466	80.24%	19.76%
2004	8,425	300,219	4,351,657	2.14	2,701,971	652,749	3,354,720	80.54%	19.46%
2005	8,323	269,420	4,633,378	2.18	2,424,780	695,007	3,119,787	77.72%	22.28%
2006	8,265	289,662	4,215,837	2.17	2,606,958	632,376	3,239,334	80.48%	19.52%
2007	8,479	295,712	4,384,355	1.59	2,661,408	657,653	3,319,061	80.19%	19.81%
2008	8,092	283,183	3,850,642	1.61	2,548,647	577,596	3,126,243	81.52%	18.48%
2009	8,201	256,310	4,158,724	1.60	2,306,790	623,809	2,930,599	78.71%	21.29%
Maximum:	8,479	304,281	4,633,378	2.45	2,738,529	695,007	3,402,950	82.23%	22.28%
Average:	8,288	285,589	4,218,292	2.01	2,570,301	632,744	3,203,045	80.23%	19.77%
Minimum:	8,092	256,310	3,607,230	1.59	2,306,790	541,085	2,930,599	77.72%	17.77%

[a] Heating Values are as follows - No. 6 Fuel Oil: 150,000 Btu/gal; Bark: 4,500 Btu/lb (wet).

Table 4-4: Baseline Actual Annual (2001 - 2009) Emissions
No. 4 Combination Boiler, Georgia-Pacific, Palatka

Source Description	Pollutant Emission Rate (TPY)										
	SO_2	NO_x	CO	PM *	PM_{10} *	$PM_{2.5}$ *	VOC	SAM	Lead	Mercury	Fluoride
2001 Actual Emissions											
-- *No. 6 Fuel Oil*	724.69	84.77	9.02	12.86	9.10	6.87	0.51	32.23	0.0027	0.0002	0.067
-- *Bark*	31.30	275.46	751.25	115.01	90.64	82.20	42.57	1.39	0.0062	0.0007	--
- Total	***755.99***	***360.23***	***760.27***	***127.87***	***99.74***	***89.07***	***43.08***	***33.62***	***0.0089***	***0.0009***	***0.067***
2002 Actual Emissions											
-- *No. 6 Fuel Oil*	824.50	104.09	11.07	15.80	11.18	8.44	0.62	36.67	0.0033	0.0003	0.083
-- *Bark*	34.23	301.24	821.56	125.77	99.12	89.90	46.55	1.52	0.0068	0.0008	--
- Total	***858.73***	***405.33***	***832.63***	***141.57***	***110.30***	***98.33***	***47.18***	***38.19***	***0.0101***	***0.0010***	***0.083***
2003 Actual Emissions											
-- *No. 6 Fuel Oil*	753.31	101.83	10.83	15.45	10.94	8.25	0.61	33.50	0.0033	0.0002	0.081
-- *Bark*	32.99	290.34	791.84	121.22	95.54	86.65	44.87	1.47	0.0065	0.0008	--
- Total	***786.30***	***392.17***	***802.67***	***136.67***	***106.47***	***94.90***	***45.48***	***34.97***	***0.0098***	***0.0010***	***0.081***
2004 Actual Emissions											
-- *No. 6 Fuel Oil*	763.63	102.26	10.88	15.52	10.98	8.29	0.61	33.96	0.0033	0.0002	0.081
-- *Bark*	33.77	297.22	810.59	124.09	97.80	88.70	45.93	1.50	0.0067	0.0008	--
- Total	***797.40***	***399.48***	***821.47***	***139.61***	***108.78***	***96.99***	***46.54***	***35.46***	***0.0100***	***0.0010***	***0.081***
2005 Actual Emissions											
-- *No. 6 Fuel Oil*	828.26	108.88	11.58	16.52	11.69	8.82	0.65	36.84	0.0035	0.0003	0.086
-- *Bark*	30.31	266.73	727.43	111.36	87.77	79.60	41.22	1.35	0.0060	0.0007	--
- Total	***858.57***	***375.61***	***739.02***	***127.88***	***99.46***	***88.42***	***41.87***	***38.18***	***0.0095***	***0.0010***	***0.086***
2006 Actual Emissions											
-- *No. 6 Fuel Oil*	750.17	99.07	10.54	15.03	10.64	8.03	0.59	33.36	0.0032	0.0002	0.079
-- *Bark*	32.59	286.77	782.09	119.73	94.36	85.58	44.32	1.45	0.0065	0.0007	--
- Total	***782.75***	***385.84***	***792.63***	***134.76***	***105.00***	***93.61***	***44.91***	***34.81***	***0.0096***	***0.0010***	***0.079***
2007 Actual Emissions											
-- *No. 6 Fuel Oil*	571.63	103.03	10.96	15.63	11.07	8.35	0.61	25.42	0.0033	0.0002	0.082
-- *Bark*	33.27	292.75	798.42	122.23	96.33	87.37	45.24	1.48	0.0066	0.0008	--
- Total	***604.90***	***395.79***	***809.38***	***137.86***	***107.40***	***95.72***	***45.86***	***26.90***	***0.0099***	***0.0010***	***0.082***
2008 Actual Emissions											
-- *No. 6 Fuel Oil*	508.36	90.49	9.63	13.73	9.72	7.33	0.54	22.61	0.0029	0.0002	0.072
-- *Bark*	31.86	280.35	764.59	117.05	92.25	83.66	43.33	1.42	0.0063	0.0007	--
- Total	***540.22***	***370.84***	***774.22***	***130.78***	***101.97***	***91.00***	***43.87***	***24.03***	***0.0092***	***0.0009***	***0.072***
2009 Actual Emissions											
-- *No. 6 Fuel Oil*	545.62	97.73	10.40	14.83	10.50	7.92	0.58	24.27	0.0031	0.0002	0.078
-- *Bark*	28.83	253.75	692.04	105.94	83.50	75.72	39.22	1.28	0.0057	0.0007	--
- Total	***574.46***	***351.48***	***702.43***	***120.77***	***93.99***	***83.65***	***39.80***	***25.55***	***0.0088***	***0.0009***	***0.078***

* PM, PM_{10}, and $PM_{2.5}$ emissions calculated from the sum of the filterable and condensable emission factors.

Table 4-5: Summary of Baseline 2-Year Average Actual Annual Emissions
No. 4 Combination Boiler, Georgia-Pacific, Palatka

Source Description	Pollutant Emission Rate (TPY)										
	SO_2	NO_x	CO	PM *	PM_{10} *	$PM_{2.5}$ *	VOC	SAM	Lead	Mercury	Fluoride
2001 - 2002 Average Emissions											
-- No. 6 Fuel Oil	774.60	94.43	10.05	14.33	10.14	7.65	0.56	34.45	0.0030	0.0002	0.075
-- Bark	32.77	288.35	786.40	120.39	94.88	86.05	44.56	1.46	0.0065	0.0008	--
- Total	***807.36***	***382.78***	***796.45***	***134.72***	***105.02***	***93.70***	***45.13***	***35.91***	***0.0095***	***0.0010***	***0.075***
2002 - 2003 Average Emissions											
-- No. 6 Fuel Oil	788.90	102.96	10.95	15.62	11.06	8.34	0.61	35.09	0.0033	0.0002	0.082
-- Bark	33.61	295.79	806.70	123.50	97.33	88.27	45.71	1.49	0.0067	0.0008	--
- Total	***822.52***	***398.75***	***817.65***	***139.12***	***108.39***	***96.62***	***46.33***	***36.58***	***0.0100***	***0.0010***	***0.082***
2003 - 2004 Average Emissions											
-- No. 6 Fuel Oil	758.47	102.05	10.86	15.48	10.96	8.27	0.61	33.73	0.0033	0.0002	0.081
-- Bark	33.38	293.78	801.22	122.66	96.67	87.67	45.40	1.48	0.0066	0.0008	--
- Total	***791.85***	***395.83***	***812.07***	***138.14***	***107.63***	***95.94***	***46.01***	***35.22***	***0.0099***	***0.0010***	***0.081***
2004 - 2005 Average Emissions											
-- No. 6 Fuel Oil	795.95	105.57	11.23	16.02	11.34	8.56	0.63	35.40	0.0034	0.0003	0.084
-- Bark	32.04	281.97	769.01	117.73	92.78	84.15	43.58	1.43	0.0063	0.0007	--
- Total	***827.99***	***387.55***	***780.24***	***133.75***	***104.12***	***92.70***	***44.21***	***36.82***	***0.0097***	***0.0010***	***0.084***
2005 - 2006 Average Emissions											
-- No. 6 Fuel Oil	789.21	103.98	11.06	15.78	11.17	8.43	0.62	35.10	0.0033	0.0002	0.083
-- Bark	31.45	276.75	754.76	115.54	91.06	82.59	42.77	1.40	0.0062	0.0007	--
- Total	***820.66***	***380.72***	***765.82***	***131.32***	***102.23***	***91.02***	***43.39***	***36.50***	***0.0096***	***0.0010***	***0.083***
2006 - 2007 Average Emissions											
-- No. 6 Fuel Oil	660.90	101.05	10.75	15.33	10.85	8.19	0.60	29.39	0.0032	0.0002	0.080
-- Bark	32.93	289.76	790.25	120.98	95.35	86.47	44.78	1.46	0.0065	0.0008	--
- Total	***693.83***	***390.81***	***801.01***	***136.31***	***106.20***	***94.66***	***45.38***	***30.86***	***0.0098***	***0.0010***	***0.080***
2007 - 2008 Average Emissions											
-- No. 6 Fuel Oil	540.00	96.76	10.29	14.68	10.39	7.84	0.58	24.02	0.0031	0.0002	0.077
-- Bark	32.56	286.55	781.51	119.64	94.29	85.52	44.29	1.45	0.0064	0.0007	--
- Total	***572.56***	***383.31***	***791.80***	***134.32***	***104.68***	***93.36***	***44.86***	***25.46***	***0.0096***	***0.0010***	***0.077***
2008 - 2009 Average Emissions											
-- No. 6 Fuel Oil	526.99	94.11	10.01	14.28	10.11	7.63	0.56	23.44	0.0030	0.0002	0.075
-- Bark	30.35	267.05	728.32	111.50	87.87	79.69	41.27	1.35	0.0060	0.0007	--
- Total	***557.34***	***361.16***	***738.33***	***125.78***	***97.98***	***87.32***	***41.83***	***24.79***	***0.0090***	***0.0009***	***0.075***
	'04 - '05	**'02 - '03**	**'02 - '03**	**'02 - '03**	**'02 - '03**	**'02 - '03**	**'02 - '03**	**'04 - '05**	**'02 - '03**	**'02 - '03**	**'04 - '05**
Highest Consecutive 2-Year Average	***827.99***	***398.75***	***817.65***	***139.12***	***108.39***	***96.62***	***46.33***	***36.82***	***0.0100***	***0.0010***	***0.084***

** PM, PM_{10}, and $PM_{2.5}$ emissions calculated from the sum of the filterable and condensable emission factors.*

Table 4-6: Summary of Baseline Actual Annual Emissions
No. 4 Combination Boiler, Georgia-Pacific, Palatka

	Year 1			Year 2			2-Year Average
Source Description	**Activity Factor**	**Emission Factor**	**Emissions (TPY) [a]**	**Activity Factor**	**Emission Factor**	**Emissions (TPY) [a]**	**(TPY)**
Sulfur Dioxide - SO_2		**2004**			**2005**		**'04 - '05**
-- No. 6 Fuel Oil	652,749 MMBtu	2.340 lb/MMBtu	763.63	695,007 MMBtu	2.383 lb/MMBtu	828.26	795.95
-- Bark	2,701,971 MMBtu	0.025 lb/MMBtu	33.77	2,424,780 MMBtu	0.025 lb/MMBtu	30.31	32.04
- Total			**797.40**			**858.57**	**827.99**
Nitrogen Oxides - NO_x		**2002**			**2003**		**'02 - '03**
-- No. 6 Fuel Oil	664,421 MMBtu	0.313 lb/MMBtu	104.09	650,000 MMBtu	0.313 lb/MMBtu	101.83	102.96
-- Bark	2,738,529 MMBtu	0.22 lb/MMBtu	301.24	2,639,466 MMBtu	0.22 lb/MMBtu	290.34	295.79
- Total			**405.33**			**392.17**	**398.75**
Carbon Monoxide - CO		**2002**			**2003**		**'02 - '03**
-- No. 6 Fuel Oil	664,421 MMBtu	0.033 lb/MMBtu	11.07	650,000 MMBtu	0.033 lb/MMBtu	10.83	10.95
-- Bark	2,738,529 MMBtu	0.6 lb/MMBtu	821.56	2,639,466 MMBtu	0.6 lb/MMBtu	791.84	806.70
- Total			**832.63**			**802.67**	**817.65**
Particulate Matter Total - PM [b]		**2002**			**2003**		**'02 - '03**
-- No. 6 Fuel Oil	664,421 MMBtu	0.048 lb/MMBtu	15.80	650,000 MMBtu	0.048 lb/MMBtu	15.45	15.62
-- Bark	2,738,529 MMBtu	0.092 lb/MMBtu	125.77	2,639,466 MMBtu	0.092 lb/MMBtu	121.22	123.50
- Total			**141.57**			**136.67**	**139.12**
Particulate Matter - PM_{10} [b]		**2002**			**2003**		**'02 - '03**
-- No. 6 Fuel Oil	664,421 MMBtu	0.034 lb/MMBtu	11.18	650,000 MMBtu	0.034 lb/MMBtu	10.94	11.06
-- Bark	2,738,529 MMBtu	0.072 lb/MMBtu	99.12	2,639,466 MMBtu	0.072 lb/MMBtu	95.54	97.33
- Total			**110.30**			**106.47**	**108.39**
Particulate Matter - $PM_{2.5}$ [b]		**2002**			**2003**		**'02 - '03**
-- No. 6 Fuel Oil	664,421 MMBtu	0.025 lb/MMBtu	8.44	650,000 MMBtu	0.025 lb/MMBtu	8.25	8.34
-- Bark	2,738,529 MMBtu	0.066 lb/MMBtu	89.90	2,639,466 MMBtu	0.066 lb/MMBtu	86.65	88.27
- Total			**98.33**			**94.90**	**96.62**
Volatile Organic Compds - VOCs		**2002**			**2003**		**'02 - '03**
-- No. 6 Fuel Oil	664,421 MMBtu	0.0019 lb/MMBtu	0.62	650,000 MMBtu	0.0019 lb/MMBtu	0.61	0.61
-- Bark	2,738,529 MMBtu	0.034 lb/MMBtu	46.55	2,639,466 MMBtu	0.034 lb/MMBtu	44.87	45.71
- Total			**47.18**			**45.48**	**46.33**
Sulfuric Acid Mist - SAM		**2004**			**2005**		**'04 - '05**
-- No. 6 Fuel Oil	652,749 MMBtu	0.104 lb/MMBtu	33.96	695,007 MMBtu	0.106 lb/MMBtu	36.84	35.40
-- Bark	2,701,971 MMBtu	0.0011 lb/MMBtu	1.50	2,424,780 MMBtu	0.0011 lb/MMBtu	1.35	1.43
- Total			**35.46**			**38.18**	**36.82**
Lead - Pb		**2002**			**2003**		**'02 - '03**
-- No. 6 Fuel Oil	664,421 MMBtu	1.01E-05 lb/MMBtu	0.00	650,000 MMBtu	1.01E-05 lb/MMBtu	0.00	0.0033
-- Bark	2,738,529 MMBtu	4.95E-06 lb/MMBtu	0.01	2,639,466 MMBtu	4.95E-06 lb/MMBtu	0.01	0.0067
- Total			**0.0101**			**0.010**	**0.0100**
Mercury - Hg		**2002**			**2003**		**'02 - '03**
-- No. 6 Fuel Oil	664,421 MMBtu	7.53E-07 lb/MMBtu	0.00	650,000 MMBtu	7.53E-07 lb/MMBtu	0.00	0.0002
-- Bark	2,738,529 MMBtu	5.73E-07 lb/MMBtu	0.00	2,639,466 MMBtu	5.73E-07 lb/MMBtu	0.00	0.0008
- Total			**0.0010**			**0.0010**	**0.0010**
Fluoride - F		**2004**			**2005**		**'04 - '05**
-- No. 6 Fuel Oil	652,749 MMBtu	0.00025 lb/MMBtu	0.08	695,007 MMBtu	0.00025 lb/MMBtu	0.09	0.084
-- Bark	2,701,971 MMBtu	-- lb/MMBtu	--	2,424,780 MMBtu	-- lb/MMBtu	--	--
- Total			**0.081**			**0.09**	**0.084**

[a] Activity Factor (MMBtu) x Emission Factor (lb/MMBtu) x 1 ton/2,000 lb = Annual Emissions (TPY)

[b] PM, PM_{10}, and $PM_{2.5}$ emission factors are the sum of the filterable and condensable emission factors.

Table 4-7: Projected Actual Annual Emissions
No. 4 Combination Boiler, Georgia-Pacific, Palatka

Pollutant	Emission Factor	Ref.	Activity Factor [a]	Total Annual Emissions (TPY) [b]
Sulfur Dioxide - SO_2				
-- *Natural Gas*	0.0006 lb/MMBtu	1	695,007 MMBtu/yr	0.21
-- *Bark*	0.025 lb/MMBtu	2	2,992,500 MMBtu/yr	37.41
			Total:	**37.61**
Nitrogen Oxides - NO_x				
-- *Natural Gas*	0.15 lb/MMBtu	3	695,007 MMBtu/yr	52.13
-- *Bark*	0.25 lb/MMBtu	4	2,992,500 MMBtu/yr	374.06
			Total:	**426.19**
Carbon Monoxide - CO				
-- *Natural Gas*	0.1 lb/MMBtu	3	695,007 MMBtu/yr	34.75
-- *Bark*	0.6 lb/MMBtu	2	2,992,500 MMBtu/yr	897.75
			Total:	**932.50**
Particulate Matter Total - PM				
-- *Natural Gas*	0.0076 lb/MMBtu	1	695,007 MMBtu/yr	2.64
-- *Bark*	0.092 lb/MMBtu	5	2,992,500 MMBtu/yr	137.43
			Total:	**140.08**
Particulate Matter - PM_{10}				
-- *Natural Gas*	0.0076 lb/MMBtu	1	695,007 MMBtu/yr	2.64
-- *Bark*	0.072 lb/MMBtu	6	2,992,500 MMBtu/yr	108.31
			Total:	**110.96**
Particulate Matter - $PM_{2.5}$				
-- *Natural Gas*	0.0076 lb/MMBtu	1	695,007 MMBtu/yr	2.64
-- *Bark*	0.066 lb/MMBtu	6	2,992,500 MMBtu/yr	98.23
			Total:	**100.88**
Volatile Organic Compds - VOCs				
-- *Natural Gas*	0.0055 lb/MMBtu	1	695,007 MMBtu/yr	1.91
-- *Bark*	0.034 lb/MMBtu	2	2,992,500 MMBtu/yr	50.87
			Total:	**52.78**
Sulfuric Acid Mist - SAM				
-- *Natural Gas*	2.67E-05 lb/MMBtu	7	695,007 MMBtu/yr	0.01
-- *Bark*	0.0011 lb/MMBtu	7	2,992,500 MMBtu/yr	1.66
			Total:	**1.67**
Lead - Pb				
-- *Natural Gas*	5.00E-07 lb/MMBtu	1	695,007 MMBtu/yr	0.0002
-- *Bark*	4.95E-06 lb/MMBtu	8	2,992,500 MMBtu/yr	0.0074
			Total:	**0.0076**
Mercury - Hg				
-- *Natural Gas*	2.60E-07 lb/MMBtu	9	695,007 MMBtu/yr	0.0001
-- *Bark*	5.73E-07 lb/MMBtu	5	2,992,500 MMBtu/yr	0.0009
			Total:	**0.0009**
Fluoride - F				
-- *Natural Gas*	-- --	--	-- --	--
-- *Bark*	-- --	--	-- --	--
			Total:	**0.0**

[a] Activity factor for bark/wood combustion is based on Palatka Mill projections of 2,992,500 MMBtu/yr from bark/wood combustion. Activity factor for natural gas combustion is based on the highest annual heat input rate from fuel oil combustion over the last 10 years (see Table 4-3).
[b] Emission factor (lb/MMBtu) x Activity Factor (MMBtu/yr) x 1 ton/2,000 lb = Annual Emissions (TPY)

References:
1. AP-42, Table 1.4-2. Natural gas heating value is 1,000 Btu/ft^3. Emission factors in lb/10^6 ft^3 are: SO_2 - 0.6, PM - 7.6, PM_{10} - 100 percent of PM, $PM_{2.5}$ - 100 percent of PM, VOC - 5.5, Pb - 0.0005. PM emission factors include both filterable and condensable PM.
2. NCASI Technical Bulletin No. 884, Table 9.6a. Uncontrolled emissions from wood combustion units.
3. Based on vendor estimates for natural gas firing.
4. Based on conservative engineering estimate.
5. Based on previous stack testing (see Table 4-2). Emission factor is the sum of the filterable PM emission factor (from stack testing) and the condensible PM emission factor (0.017 lb/MMBtu) from AP-42, Table 1.6-1.
6. NCASI Technical Bulletin No. 884, Table 9.6b, PM emissions from wood combustion units with ESP control. Filterable PM_{10} and $PM_{2.5}$ emissions are 74 percent and 65 percent of PM emissions, respectively. Condensable PM emissions are 0.017 lb/MMBtu based on AP-42, Table 1.6-1.
7. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3.63% of SO_2 becomes SO_3, then multiply by the ratio of H_2SO_4 and SO_3 molecular weights (98/80).
8. NCASI Technical Bulletin No. 973, Table 7.2, Summary of Trace Metal Emissions from Wood-Fired Boilers with ESP control, median value.
9. AP-42, Table 1.4-4. Natural gas heating value is 1,000 Btu/ft^3. Hg emission factor is 0.00026 lb/10^6 ft^3.

Table 4-8: Determination of Operating Rate that Could Have Been Accommodated during the Baseline Period No. 4 Combination Boiler, Georgia-Pacific, Palatka

Date	Bark Consumption (Tons)	Bark Consumption (MMBtu)	Number of Days in Month	Average Hourly Heat Input (MMBtu/hr) [a]
January 2002	31,152	280,368	31	376.84
February 2002	26,567	239,101	28	355.80
March 2002	20,565	185,088	31	248.77
April 2002	29,497	265,472	30	368.71
May 2002	24,993	224,934	31	302.33
June 2002	23,390	210,506	30	292.37
July 2002	28,084	252,755	31	339.72
August 2002	22,241	200,173	31	269.05
September 2002	25,665	230,982	30	320.81
October 2002	19,933	179,400	31	241.13
November 2002	25,864	232,773	30	323.30
December 2002	26,331	236,977	31	318.52
January 2003	31,094	279,846	31	376.14
February 2003	24,862	223,757	28	332.97
March 2003	23,749	213,745	31	287.29
April 2003	31,221	280,988	30	390.26
May 2003	23,166	208,491	31	280.23
June 2003	23,232	209,092	30	290.41
July 2003	30,907	278,165	31	373.88
August 2003	21,487	193,381	31	259.92
September 2003	19,969	179,718	30	249.61
October 2003	8,204	73,839	31	99.25
November 2003	24,489	220,402	30	306.11
December 2003	30,894	278,043	31	373.71
		Highest Average Hourly Heat Input Rate:		**390.26**
		Operating Hours: [b]		**8,302**
		Could Have Accommodated Total Annual Heat Input Rate: [c]		**3,239,946**
January 2004	30,642	275,782	31	370.67
February 2004	26,183	235,651	29	338.58
March 2004	26,708	240,371	31	323.08
April 2004	33,253	299,275	30	415.66
May 2004	26,217	235,955	31	317.14
June 2004	24,185	217,665	30	302.31
July 2004	28,812	259,306	31	348.53
August 2004	22,880	205,918	31	276.77
September 2004	16,466	148,194	30	205.82
October 2004	26,180	235,616	31	316.69
November 2004	15,892	143,027	30	198.65
December 2004	22,801	205,212	31	275.82
January 2005	29,084	261,756	31	351.82
February 2005	22,543	202,887	28	301.92
March 2005	12,120	109,080	31	146.61
April 2005	28,343	255,087	30	354.29
May 2005	20,438	183,942	31	247.23
June 2005	21,907	197,163	30	273.84
July 2005	27,761	249,849	31	335.82
August 2005	19,619	176,571	31	237.33
September 2005	18,848	169,632	30	235.60
October 2005	25,744	231,696	31	311.42
November 2005	19,131	172,179	30	239.14
December 2005	23,882	214,938	31	288.90
		Highest Average Hourly Heat Input Rate:		**415.66**
		Operating Hours: [b]		**8,425**
		Could Have Accommodated Total Annual Heat Input Rate: [c]		**3,501,937**

[a] Based on monthly totals divided by number of days per month and 24 hours per day.

[b] See Table 4-3. Highest annual operating hours during each baseline period.

[c] Highest average hourly heat input rate due to bark/wood only multiplied by the highest annual hours of operation during the baseline period. This represents the heat input rate that could have been accommodated during the baseline period. The burner replacement project will not increase the annual heat input to the No. 4 Combination Boiler from fossil fuels, and emissions associated with firing of any fuel are allowed to be excluded from the projected actual emissions.

Highest hourly heat input rate (MMBtu/hr) x Operating hours (hr/yr) = Could Have Accommodated Total Annual Heat Input Rate (MMBtu/yr)

Table 4-9: Emissions that Could Have Been Accommodated during the Baseline Period No. 4 Combination Boiler, Georgia-Pacific, Palatka

Pollutant	Emission Factor [a]	Activity Factor [b]	Total Annual Emissions (TPY) [c]
Sulfur Dioxide - SO_2			
-- Bark	0.025 lb/MMBtu	2,880,675 MMBtu/yr	36.01
Nitrogen Oxides - NO_x			
-- Bark	0.22 lb/MMBtu	2,880,675 MMBtu/yr	316.87
Carbon Monoxide - CO			
-- Bark	0.6 lb/MMBtu	2,880,675 MMBtu/yr	864.20
Particulate Matter Total - PM			
-- Bark	0.092 lb/MMBtu	2,880,675 MMBtu/yr	132.30
Particulate Matter - PM_{10}			
-- Bark	0.072 lb/MMBtu	2,880,675 MMBtu/yr	104.27
Particulate Matter - $PM_{2.5}$			
-- Bark	0.066 lb/MMBtu	2,880,675 MMBtu/yr	94.56
Volatile Organic Compounds - VOCs			
-- Bark	0.034 lb/MMBtu	2,880,675 MMBtu/yr	48.97
Sulfuric Acid Mist - SAM			
-- Bark	0.0011 lb/MMBtu	2,880,675 MMBtu/yr	1.60
Lead - Pb			
-- Bark	4.95E-06 lb/MMBtu	2,880,675 MMBtu/yr	0.0071
Mercury - Hg			
-- Bark	5.73E-07 lb/MMBtu	2,880,675 MMBtu/yr	0.0008
Fluoride - F			
-- Bark	-- --	-- --	--

[a] Emission factors based on the average factor during the baseline years (2004 - 2005 for SO_2, SAM, and F, 2002 - 2003 for all other pollutants).

[b] Activity factors based on annual heat input rate that could have been accommodated during the baseline period due to bark burning (3,239,946 MMBtu/yr for 2002 - 2003; 3,501,937 MMBtu/yr for 2004 - 2005). Because the heat input rate that could have been accommodated due to bark burning is higher than the projected actual hea input rate, the heat input rate was reduced to the projected actual heat input rate (2,992,500 MMBtu/yr; see Table 4-7) minus the restored heat input rate (111,825 MMBtu/yr). The restored heat input rate is based on recovering 35 TPD of bark/wood burning capacity as a result of the dust collector and ID fan projects, and a total of 355 days/year operation.

Restored Heat Input Rate: 35 TPD x 355 days/yr x 9 MMBtu/ton = 111,825 MMBtu/yr

Could Have Accommodated: 2,992,500 MMBtu/yr - 111,825 MMBtu/yr = 2,880,675 MMBtu/yr

[c] Represents the actual emissions that the unit could have accommodated prior to the project.

Emission factor (lb/MMBtu) x Activity Factor (MMBtu/yr) x 1 ton/2,000 lb = Annual Emissions (TPY)

Table 4-10: PSD Applicability Analysis
No. 4 Combination Boiler, Georgia-Pacific, Palatka

Source Description	Pollutant Emission Rate (TPY)										
	SO_2	NO_x	CO	PM [a]	PM_{10} [a]	$PM_{2.5}$ [a]	VOC	SAM	Lead	Mercury	Fluoride
EMISSIONS THAT COULD HAVE BEEN ACCOMMODATED AND ARE UNRELATED TO THE PROJECT [b]											
-- *Bark*	36.01	316.87	864.20	132.30	104.27	94.56	48.97	1.60	0.0071	0.0008	--
-- Total	**36.01**	**316.87**	**864.20**	**132.30**	**104.27**	**94.56**	**48.97**	**1.60**	**0.0071**	**0.0008**	**--**
BASELINE ACTUAL Emissions [c]											
-- *No. 6 Fuel Oil*	795.95	102.96	10.95	15.62	11.06	8.34	0.61	35.40	0.0033	0.0002	0.084
-- *Bark*	32.04	295.79	806.70	123.50	97.33	88.27	45.71	1.43	0.0067	0.0008	--
-- Total	**827.99**	**398.75**	**817.65**	**139.12**	**108.39**	**96.62**	**46.33**	**36.82**	**0.0100**	**0.0010**	**0.084**
DEMAND GROWTH EXCLUDED Emissions [d]	**--**	**--**	**46.55**	**--**	**--**	**--**	**2.65**	**--**	**--**	**--**	**--**
PROJECTED ACTUAL Emissions [e]											
-- *Natural Gas*	0.21	52.13	34.75	2.64	2.64	2.64	1.91	0.01	0.0002	0.0001	--
-- *Bark*	37.41	374.06	897.75	137.43	108.31	98.23	50.87	1.66	0.0074	0.0009	--
-- Total	**37.61**	**426.19**	**932.50**	**140.08**	**110.96**	**100.88**	**52.78**	**1.67**	**0.0076**	**0.0009**	**--**
BASELINE ACTUAL Emissions [c]											
-- *No. 6 Fuel Oil*	795.95	102.96	10.95	15.62	11.06	8.34	0.61	35.40	0.0033	0.0002	0.084
-- *Bark*	32.04	295.79	806.70	123.50	97.33	88.27	45.71	1.43	0.0067	0.0008	--
-- Total	**827.99**	**398.75**	**817.65**	**139.12**	**108.39**	**96.62**	**46.33**	**36.82**	**0.0100**	**0.0010**	**0.084**
DEMAND GROWTH EXCLUDED Emissions [d]	**--**	**--**	**46.55**	**--**	**--**	**--**	**2.65**	**--**	**--**	**--**	**--**
Increase Due to Project [f]	**-790.37**	**27.44**	**68.30**	**0.96**	**2.57**	**4.26**	**3.81**	**-35.15**	**-0.0024**	**-0.0001**	**-0.084**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	10	40	7	0.6	0.1	3
PSD REVIEW TRIGGERED?	No	No	No	No	No	No	No	No	No	No	No

[a] PM, PM_{10}, and $PM_{2.5}$ emissions calculated from the sum of the filterable and condensable emission factors.

[b] See Table 4-9 for emissions that could have been accommodated during the baseline period.

[c] See Table 4-6 for Baseline Actual Emissions.

[d] Emissions That Could Have Been Accommodated minus Baseline Actual Emissions. Represents the emissions above the Baseline Actual Emissions that may be excluded from the Projected Actual Emissions due to demand growth.

[e] See Table 4-7 for Projected Actual Emissions.

[f] Projected Actual Emissions minus Baseline Actual Emissions minus Demand Growth Excluded Emissions.

APPENDIX A

REFERENCES FOR EMISSION FACTORS

C.11. Visible Emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C and shall be performed once each federal fiscal year [Construction permit No. 1070005-017-AC; PCP Exclusion dated March 14, 2002 and Title V Permit No. 1070005-023-AV]

MONITORING REQUIREMENTS

C.12. The steam production rate in lbs/hr including the pressure in psig and the temperature in °F, and the No. 6 fuel oil feed rate per hour shall be monitored and recorded.
[Construction Permit No. AC54-163040]

EXCESS EMISSIONS

C.13. Excess Emissions - Startup/Shutdown. Excess Emissions due to startup and shutdown are conditionally allowed for up to 8 hours in any 24-hour period unless specifically authorized by the Department for longer duration.

{Permitting Note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.}
[Rule 62-210.700, F.A.C.]

C.14. Periods of excess emissions reported under 40 CFR Part 63, Subpart A) shall not be a violation of Conditions N.4. AND N.8, provided that the total time of excess emissions (excluding periods of startup, shutdown, or malfunction) divided by the total process operating time in a semi-annual reporting period does not exceed 1% for the Thermal Oxidizer and No. 4 Combination Boiler combined.
[40 CFR 63.443(e)1; Construction Permit No. 1070005-017-AC; PCP Exclusion dated March 14, 2002]

C.15. Excess Emissions. This emissions unit is also subject to applicable Excess Emissions requirements in Subsection T.

{Permitting Note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.]

RECORDKEEPING

C.16. Sulfur Dioxide Emissions. In lieu of stack testing, SO_2 emissions due to the burning of fuel oil shall be determined as follows:

(%S oil/100) x 8.2 lbs/gal x lb mole S/32 lbs S x lb mole SO_2/lb mole S x 64 lbs SO_2/lb mole SO_2= (0.164 x %S) lbs SO_2/gal

(0.164 x %S) lbs SO_2/gal x gallons of fuel oil fired = lbs SO_2

C.16. continued:

For purposes of this condition, SO_2 emissions due to burning of NCGs will be determined as follows:

Duration of NCG burning (minutes) ÷ 60 min/hr x 302.4 lbs/hr = lbs SO_2

For purposes of this condition, SO_2 emissions due to burning of SOGs will be determined as follows:

Duration of SOG burning (minutes) ÷ 60 min/hr x 324.0 lbs/hr = lbs SO_2

For purposes of this condition, daily SO_2 emissions from the #4CB due to burning of DNCGs will be determined as follows:

> (Daily production in Tons ADUP x 0.35 lbs-S /ton ADUP x 2 lbs SO2/1lb-S) x Minutes DNCG's burned in #4CB/1440 minutes/day = lbs SO2 / day from #4CB

A record shall be maintained for at least five years of the following:

> The date, time, and duration DNCGs/NCGs/SOGs are fired in the boiler,[1]
> The sulfur content of the fuel oil fired (based upon a three barge rolling average),
> The amount (gallons) of fuel oil fired,
> The certified on-specification used oil analysis (when on-spec used oil is fired).
>
> [1]The mill shall obtain this information from the plant data process information system or the Operators' DNCG Diversion log as backup to the plant data process information system.
>
> The total SO_2 emissions, in tons, attributed to any NCG, SOG and/or DNCG burning, shall be the sum of the previous NCG, SOG and/or DNCG burning in either the No. 4 Combination Boiler or the No. 5 Power Boiler conducted during the year to date.
>
> A SO_2 emissions report of the above data shall be submitted to the Compliance Section of the Northeast District Office on an annual basis (by April 1 for the previous year).

[Construction Permit No. 1070005-017-AC; PCP Exclusion dated March 12, 2002; PCP Exclusion dated April 23, 2004 and Construction Permit No. 1070005-024-AC]

Table 1.3-1. CRITERIA POLLUTANT EMISSION FACTORS FOR FUEL OIL COMBUSTION[a]

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e]		Filterable PM[f]	
	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING
Boilers > 100 Million Btu/hr										
No. 6 oil fired, normal firing (1-01-004-01), (1-02-004-01), (1-03-004-01)	157S	A	5.7S	C	47	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, normal firing, low NO_x burner (1-01-004-01), (1-02-004-01)	157S	A	5.7S	C	40	B	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, (1-01-004-04)	157S	A	5.7S	C	32	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, low NO_x burner (1-01-004-04)	157S	A	5.7S	C	26	E	5	A	9.19(S)+3.22	A
No. 5 oil fired, normal firing (1-01-004-05), (1-02-004-04)	157S	A	5.7S	C	47	B	5	A	10	B
No. 5 oil fired, tangential firing (1-01-004-06)	157S	A	5.7S	C	32	B	5	A	10	B
No. 4 oil fired, normal firing (1-01-005-04), (1-02-005-04)	150S	A	5.7S	C	47	B	5	A	7	B
No. 4 oil fired, tangential firing (1-01-005-05)	150S	A	5.7S	C	32	B	5	A	7	B
No. 2 oil fired (1-01-005-01), (1-02-005-01), (1-03-005-01)	142S[h]	A	5.7S	C	24	D	5	A	2	A
No.2 oil fired, LNB/FGR, (1-01-005-01), (1-02-005-01), (1-03-005-01)	142S[h]	A	5.7S	A	10	D	5	A	2	A

Table 1.3-1. (cont.)

Firing Configuration (SCC)[a]	SO_2[b] Emission Factor (lb/10^3 gal)	SO_2[b] EMISSION FACTOR RATING	SO_3[c] Emission Factor (lb/10^3 gal)	SO_3[c] EMISSION FACTOR RATING	NO_x[d] Emission Factor (lb/10^3 gal)	NO_x[d] EMISSION FACTOR RATING	CO[e] Emission Factor (lb/10^3 gal)	CO[e] EMISSION FACTOR RATING	Filterable PM[f] Emission Factor (lb/10^3 gal)	Filterable PM[f] EMISSION FACTOR RATING
Boilers < 100 Million Btu/hr										
No. 6 oil fired (1-02-004-02/03) (1-03-004-02/03)	157S	A	2S	A	55	A	5	A	9.19(S)+3.22[i]	B
No. 5 oil fired (1-03-004-04)	157S	A	2S	A	55	A	5	A	10[i]	A
No. 4 oil fired (1-03-005-04)	150S	A	2S	A	20	A	5	A	7	B
Distillate oil fired (1-02-005-02/03) (1-03-005-02/03)	142S	A	2S	A	20	A	5	A	2	A
Residential furnace (A2104004/A2104011)	142S	A	2S	A	18	A	5	A	0.4[g]	B

a To convert from lb/103 gal to kg/103 L, multiply by 0.120. SCC = Source Classification Code.
b References 1-2,6-9,14,56-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.
c References 1-2,6-8,16,57-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.
d References 6-7,15,19,22,56-62. Expressed as NO2. Test results indicate that at least 95% by weight of NOx is NO for all boiler types except residential furnaces, where about 75% is NO. For utility vertical fired boilers use 105 lb/103 gal at full load and normal (>15%) excess air. Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are related to fuel nitrogen content, estimated by the following empirical relationship: lb NO2 /103 gal = 20.54 + 104.39(N), where N is the weight % of nitrogen in the oil. For example, if the fuel is 1% nitrogen, then N = 1.
e References 6-8,14,17-19,56-61. CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.
f References 6-8,10,13-15,56-60,62-63. Filterable PM is that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. Particulate emission factors for residual oil combustion are, on average, a function of fuel oil sulfur content where S is the weight % of sulfur in oil. For example, if fuel oil is 1% sulfur, then S = 1.
g Based on data from new burner designs. Pre-1970's burner designs may emit filterable PM as high as 3.0 lb/103 gal.
h The SO2 emission factor for both no. 2 oil fired and for no. 2 oil fired with LNB/FGR, is 142S, not 157S. Errata dated April 28, 2000. Section corrected May 2010.
i The PM factors for No.6 and No. 5 fuel were reversed. Errata dated April 28, 2000. Section corrected May 2010.

Table 1.3-2. CONDENSABLE PARTICULATE MATTER EMISSION FACTORS FOR OIL COMBUSTION[a]

Firing Configuration[b] (SCC)	Controls	CPM - TOT[c, d]		CPM - IOR[c, d]		CPM - ORG[c, d]	
		Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING
No. 2 oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	All controls, or uncontrolled	1.3[d, e]	D	65% of CPM-TOT emission factor[c]	D	35% of CPM-TOT emission factor[c]	D
No. 6 oil fired (1-01-004-01/04, 1-02-004-01, 1-03-004-01)	All controls, or uncontrolled	1.5[f]	D	85% of CPM-TOT emission factor[d]	E	15% of CPM-TOT emission factor[d]	E

[a] All condensable PM is assumed to be less than 1.0 micron in diameter.
[b] No data are available for numbers 3, 4, and 5 oil. For number 3 oil, use the factors provided for number 2 oil. For numbers 4 and 5 oil, use the factors provided for number 6 oil.
[c] CPM-TOT = total condensable particulate matter.
CPM-IOR = inorganic condensable particulate matter.
CPM-ORG = organic condensable particulate matter.
[d] To convert to lb/MMBtu of No. 2 oil, divide by 140 MMBtu/10^3 gal. To convert to lb/MMBtu of No. 6 oil, divide by 150 MMBtu/10^3 gal.
[e] References: 76-78.
[f] References: 79-82.

Table 1.3-3. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: A

Firing Configuration (SCC)	TOC[b] Emission Factor ($lb/10^3$ gal)	Methane[b] Emission Factor ($lb/10^3$ gal)	NMTOC[b] Emission Factor ($lb/10^3$ gal)
Utility boilers			
No. 6 oil fired, normal firing (1-01-004-01)	1.04	0.28	0.76
No. 6 oil fired, tangential firing (1-01-004-04)	1.04	0.28	0.76
No. 5 oil fired, normal firing (1-01-004-05)	1.04	0.28	0.76
No. 5 oil fired, tangential firing (1-01-004-06)	1.04	0.28	0.76
No. 4 oil fired, normal firing (1-01-005-04)	1.04	0.28	0.76
No. 4 oil fired, tangential firing (1-01-005-05)	1.04	0.28	0.76
Industrial boilers			
No. 6 oil fired (1-02-004-01/02/03)	1.28	1.00	0.28
No. 5 oil fired (1-02-004-04)	1.28	1.00	0.28
Distillate oil fired (1-02-005-01/02/03)	0.252	0.052	0.2
No. 4 oil fired (1-02-005-04)	0.252	0.052	0.2
Commercial/institutional/residential combustors			
No. 6 oil fired (1-03-004-01/02/03)	1.605	0.475	1.13
No. 5 oil fired (1-03-004-04)	1.605	0.475	1.13
Distillate oil fired (1-03-005-01/02/03)	0.556	0.216	0.34
No. 4 oil fired (1-03-005-04)	0.556	0.216	0.34
Residential furnace (A2104004/A2104011)	2.493	1.78	0.713

a To convert from lb/103 gal to kg/103 L, multiply by 0.12. SCC = Source Classification Code.

b References 29-32. Volatile organic compound emissions can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

Table 1.3-4. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UTILITY BOILERS FIRING RESIDUAL OILa

	Cumulative Mass % Stated Size			Cumulative Emission Factor lb/10^3 gal)					
		Controlled		Uncontrolled[c]		ESP Controlled[d]		Scrubber Controlled[e]	
Particle Size[b] (µm)	Uncon- trolled	ESP	Scrubber	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
15	80	75	100	6.7A	C	0.05A	E	0.50A	D
10	71	63	100	5.9A	C	0.042A	E	0.50A	D
6	58	52	100	4.8A	C	0.035A	E	0.50A	D
2.5	52	41	97	4.3A	C	0.028A	E	0.48A	D
1.25	43	31	91	3.6A	C	0.021A	E	0.46A	D
1.00	39	28	84	3.3A	C	0.018A	E	0.42A	D
0.625	20	20	64	1.7A	C	0.007A	E	0.32A	D
TOTAL	100	100	100	8.3A	C	0.067A	E	0.50A	D

a Reference 26. Source Classification Codes 1-01-004-01/04/05/06 and 1-01-005-04/05. To convert from lb/103 gal to kg/m3, multiply by 0.120. ESP = electrostatic precipitator.
b Expressed as aerodynamic equivalent diameter.
c Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the oil. For example, if the fuel is 1.00% sulfur, then S = 1.
No. 6 oil: A = 1.12(S) + 0.37
No. 5 oil: A = 1.2
No. 4 oil: A = 0.84
d Estimated control efficiency for ESP is 99.2%.
e Estimated control efficiency for scrubber is 94%

Table 1.3-11. EMISSION FACTORS FOR METALS FROM UNCONTROLLED NO. 6 FUEL OIL COMBUSTION[a]

Metal	Average Emission Factor[b, d] (lb/10^3 Gal)	EMISSION FACTOR RATING
Antimony	5.25E-03[c]	E
Arsenic	1.32E-03	C
Barium	2.57E-03	D
Beryllium	2.78E-05	C
Cadmium	3.98E-04	C
Chloride	3.47E-01	D
Chromium	8.45E-04	C
Chromium VI	2.48E-04	C
Cobalt	6.02E-03	D
Copper	1.76E-03	C
Fluoride	3.73E-02	D
Lead	1.51E-03	C
Manganese	3.00E-03	C
Mercury	1.13E-04	C
Molybdenum	7.87E-04	D
Nickel	8.45E-02	C
Phosphorous	9.46E-03	D
Selenium	6.83E-04	C
Vanadium	3.18E-02	D
Zinc	2.91E-02	D

[a] Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.

[b] References 64-72. 18 of 19 sources were uncontrolled and 1 source was controlled with low efficiency ESP. To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12.

[c] References 29-32,40-44.

[d] For oil/water mixture, reduce factors in proportion to water content of the fuel (due to dilution). To adjust the listed values for water content, multiply the listed value by 1-decimal fraction of water (ex: For fuel with 9 percent water by volume, multiply by 1-0.9=.91).

Table 1.6-1. EMISSION FACTORS FOR PM FROM WOOD RESIDUE COMBUSTION[a]

Fuel	PM Control Device	Filterable PM		Filterable PM-10[b]		Filterable PM-2.5[b]	
		Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING
Bark/Bark and Wet Wood	No Control[c]	0.56[d]	C	0.50[e]	D	0.43[e]	D
Dry Wood	No Control[c]	0.40[f]	A	0.36[e]	D	0.31[e]	D
Wet Wood	No Control[c]	0.33[g]	A	0.29[e]	D	0.25[e]	D
Bark	Mechanical Collector	0.54[h]	D	0.49[e]	D	0.29[e]	D
Bark and Wet Wood	Mechanical Collector	0.35[i]	C	0.32[e]	D	0.19[e]	D
Dry Wood	Mechanical Collector	0.30[j]	A	0.27[e]	D	0.16[e]	D
Wet Wood	Mechanical Collector	0.22[k]	A	0.20[e]	D	0.12[e]	D
All Fuels[m]	Electrolyzed Gravel Bed	0.1[m]	D	0.074[e]	D	0.065[e]	D
All Fuels[m]	Wet Scrubber	0.066[n]	A	0.065[e]	D	0.065[e]	D
All Fuels[m]	Fabric Filter	0.1[o]	C	0.074[e]	D	0.065[e]	
All Fuels[m]	Electrostatic Precipitator	0.054[p]	B	0.04[e]	D	0.035[e]	
		Condensible PM					
All Fuels[m]	All Controls/No Controls	0.017[q]	A				

fire coal, 93 could co-fire residual oil, 25 could co-fire distillate oil; 111 boilers could co-fire natural gas and 76 burned waste treatment system residuals.

When wood is burned alone, the principal emissions of concern are particulates, CO, and NO_x. The ash content of bark is on the order of 1 to 2%, about an order of magnitude lower than coal. Particulate emissions result from inorganic materials contained in the bark and wood itself and from carbonaceous material resulting from incomplete combustion. Like coal, uncontrolled particulate emissions will be greater where fly ash reinjection is practiced. NO_x emissions are mainly the result of "fuel NO_x," with bark nitrogen contents being in the 0.1 to 0.2% range. Average NO_x emissions from wood combustion in typical pulp mill boilers are lower than those from coal or residual oil combustion, and slightly higher than average NO_x emissions from natural gas burning. However, if any wood fuels containing nitrogen from other sources (e.g., urea formaldehyde resin) are burned, additional NO_x emissions can be expected.

SO_2 emissions from wood combustion are very low, since bark and other wood residues contain little sulfur (NCASI 1978b). CO emissions and other products of incomplete combustion are highly variable and are a function of boiler design, operating conditions, combustion efficiency and fuel quality. Tables 9.6a and b provide estimates of emissions for several criteria pollutants resulting from wood residue combustion in boilers (USEPA 2001; NCASI 1993). The AP-42 TPM emission factors for wood combustion units with wet scrubbers, fabric filters and electrostatic precipitators shown in Table 9.6b should be used with caution. The factor for units with fabric filters (0.10 lb/10^6 Btu) is shown to be larger than that for wet scrubbers (0.066 lb/10^6 Btu), which may be due to amount of data available in each category. Similarly, the factor for units with ESPs is given as 0.054 lb/10^6 Btu, barely below that for units with wet scrubbers, while in reality, the TPM emissions from units with ESPs are expected to be considerably smaller.

Table 9.6a Uncontrolled VOC, CO, SO_2, and NO_x Emissions from Wood Combustion Units[a] (USEPA 2003; NCASI 1993)

	No. of Sources Tested	Range	Emission Factor lb/10^6 Btu	Emission Factor kg/10^9 J
Volatile Organic Compounds[b]				
Stoker	39	ND to 0.21	0.034	0.0146
Fuel Cell/Dutch Oven	15	ND to 0.05	0.016	0.00688
Fluidized Bed Combustor	4	ND to 0.005	0.001	0.00043
Carbon Monoxide				
Stokers, Dutch Ovens/fuel cells [c]	128	0.028 to 2.6	0.60	0.258
Fluid Bed Combustors [c]	9	0.016 to 0.94	0.17	0.073
Sulfur Dioxide [d] – all sizes & types			0.025	0.011
Oxides of Nitrogen – all sizes & types			0.22 [e, g] 0.49 [f, g]	0.095 0.211

[a] Nominal values achievable under normal operating conditions. CO emissions may be one to two orders of magnitude higher when combustion is not complete; [b] as C - measured using EPA Method 25A; [c] Value is for both wet and dry wood-fired boilers; [d] Value is for both wet and dry wood-fired boilers; based on an average gross heating value of 9000 Btu/lb of dry wood; [e] value is for wet (≥20% moisture content, wet basis) wood; [f] value is for dry (< 20% moisture content, wet basis) wood; [g] based on an average higher heating value of 9000 Btu/lb of dry wood

Table 9.6b Filterable TPM, PM_{10}, and $PM_{2.5}$ Emissions from Wood Combustion Units (USEPA 2003)

PM Control Device	PM_{10}, $PM_{2.5}$ as % of TPM Cumulative Mass: PM_{10}	$PM_{2.5}$	Wood Fuel Fired	TPM Emission Factor: lb/10^6 Btu[a]	kg/10^9J
None	90[c]	76[c]	Bark Bark and Wet Wood	0.56	0.24
			Dry Wood	0.40	0.17
			Wet Wood	0.33	0.14
Mechanical Collector [b]	91[c] / 32[d]	54[c] / 16[d]	Bark	0.54	0.23
			Bark and Wet Wood	0.35	0.15
			Dry Wood	0.30	0.13
			Wet Wood	0.22	0.095
Electrolyzed Gravel Bed	74	65	Bark Bark and Wet Wood Dry Wood Wet Wood	0.1	0.04
Wet Scrubber	98	98	Bark Bark and Wet Wood Dry Wood Wet Wood	0.066	0.028
Fabric Filter	74	65	Bark Bark and Wet Wood Dry Wood Wet Wood	0.1	0.04
Electrostatic Precipitator	74[e]	65[e]	Bark Bark and Wet Wood Dry Wood Wet Wood	0.054	0.023

[a]based on an average higher heating value of 9000 Btu/lb of dry wood; [b]mechanical collectors include cyclones and multiclones; [c] with flyash reinjection; [d]without flyash reinjection; [e]in a recent NCASI study, the PM_{10} and $PM_{2.5}$ fractions for a bark boiler with an ESP were 67% and 27% of TPM emissions, respectively (NCASI 2002d)

9.5 Combination Wood-Fired Boilers

While wood is the sole fuel fired in some pulp mill wood-fired boilers, most boilers burn wood in combination with one or more fossil fuels. As a first approximation, for combustion sources firing gas, oil, or coal along with wood residues, estimates for criteria pollutant emissions may be obtained by assigning emission factors for the individual fuels as though they were to be fired exclusively and then multiplying these by the corresponding heat input fraction. For example, if a boiler burns 40% gas and 60% wood residues, the boiler emission factor would be equal to the appropriate gas emission factor x 0.4 + appropriate wood emission factor x 0.6. SO_2 and NO_x emissions from combination boilers firing wood with other fuels can perhaps be dealt with differently.

9.5.1 *SO_2 Emissions from Combination Wood-Fired Boilers*

When wood residues are burned along with other sulfur-containing fuels, as well as kraft mill NCGs, a significant amount of the fuel and NCG sulfur can be captured within the boiler itself by the alkaline wood ash (NCASI 1992). From an input-output analysis of several sets of data corresponding to boilers burning wood residues in combination with oil, coal, non-condensible gases, etc., NCASI developed the following preliminary correlation for sulfur capture in combination bark boilers (pre-scrubber or boilers without scrubbers) (Someshwar and Jain 1993; NCASI 1992):

Table 7.2 Summary of Trace Metal Emissions from Wood-Fired Boilers (lb/10^6 Btu)

Trace Metal	PM Control Device	Sources*	Detects	Min.	Max.	Median	Mean	Std. Dev.	UPL**
Antimony	Fabric Filter	1	1	--	--	4.23E-07	4.23E-07	--	--
Antimony	Wet Scrubber	2,1	1	--	--	4.98E-07	4.98E-07	--	--
Arsenic	ESP/Fabric Filter	10,9	7	1.29E-07	2.91E-06	3.21E-07	8.11E-07	9.23E-07	2.33E-06
Arsenic	Mechanical Collector	8	7	1.58E-09	4.50E-05	3.02E-06[a]	1.04E-05	1.48E-05	4.76E-05
Arsenic	Wet Scrubber	7,6	5	2.49E-11	7.15E-06	1.84E-06	2.86E-06	2.73E-06	7.35E-06
Barium	Fabric Filter	2	2	1.59E-04	2.60E-04	2.10E-04	2.10E-04	--	--
Barium	Wet Scrubber	4,3	3	6.69E-06	8.15E-05	2.02E-05	3.61E-05	3.99E-05	1.02E-04
Barium	Mechanical Collector	1	1	--	--	4.83E-03	4.83E-03	--	--
Beryllium	ESP/Fabric Filter	5	2	<3.24E-07	5.68E-06	3.27E-07	3.27E-06	1.20E-06	6.41E-06
Beryllium	Mechanical Collector	5	1	<3.0E-07	1.40E-04	4.27E-05	4.27E-05	--	1.40E-04
Beryllium	Wet Scrubber	5	2	<1.73E-12	1.85E-06	3.41E-07	1.23E-06	3.12E-07	2.04E-06
Cadmium	ESP/Fabric Filter	9	8	2.21E-07	6.04E-06	3.73E-07	1.68E-06	2.26E-06	7.35E-06
Cadmium	Mechanical Collector	9,8	8	1.90E-06	1.63E-05	4.67E-06	6.00E-06	4.72E-06	1.38E-05
Cadmium	Wet Scrubber	9	8	<6.02E-13	1.49E-05	1.85E-06	4.06E-06	5.53E-06	1.79E-05
Chromium	ESP/Fabric Filter	10	10	1.78E-07	3.10E-05	8.04E-07	4.34E-06	9.48E-06	2.80E-05
Chromium	Mechanical Collector	11	11	9.17E-06	1.61E-04	3.46E-05	5.26E-05	5.22E-05	1.82E-04
Chromium	Wet Scrubber	9	9	3.99E-12	4.86E-05	5.06E-06	1.21E-05	1.57E-05	5.14E-05
Chromium^{+6} [b]	ESP/Fabric Filter	5,2	2	5.90E-08	4.86E-07	2.72E-07	2.72E-07	--	--
Chromium^{+6}	Mechanical Collector	3,2	2	6.61E-06	7.33E-06	6.97E-06	6.97E-06	--	--
Chromium^{+6}	Wet Scrubber	2,1	1	--	--	2.35E-07	2.35E-07	--	--
Cobalt	Fabric Filter	2	2	1.86E-07	7.50E-07	4.68E-07	4.68E-07	--	--
Cobalt	Mechanical Collector	4	4	5.06E-06	4.25E-04	1.96E-05	1.17E-04	2.05E-04	4.56E-04
Cobalt	Wet Scrubber	1	1	--	--	1.97E-07	1.97E-07	--	--
Copper	ESP/Fabric Filter	6	6	2.54E-06	1.10E-05	4.14E-06	4.99E-06	3.15E-06	1.02E-05
Copper	Mechanical Collector	11	11	1.00E-07	4.25E-04	1.02E-04	1.12E-04	1.18E-04	4.06E-04
Copper	Wet Scrubber	8	8	2.78E-11	4.89E-05	1.34E-05	1.82E-05	1.69E-05	4.61E-05
Lead	ESP/Fabric Filter	10	10	9.23E-07	5.49E-05	4.95E-06	9.91E-06	1.62E-05	5.05E-05
Lead	Mechanical Collector	8	8	3.82E-08	2.84E-04	1.77E-05	8.71E-05	1.23E-04	3.97E-04
Lead	Wet Scrubber	11	11	1.60E-11	1.78E-04	1.66E-05	4.72E-05	6.04E-05	1.97E-04
Manganese	ESP/Fabric Filter	8,7	7	1.01E-05	4.44E-04	3.50E-05	9.55E-05	1.56E-04	4.92E-04
Manganese	Mechanical Collector	11	11	1.56E-06	1.04E-02	1.81E-03	3.11E-03	3.02E-03	8.10E-03
Manganese	Wet Scrubber	7,6	6	9.66E-11	1.11E-04	2.62E-05	3.77E-05	3.99E-05	1.04E-04

(Continued on next page. See notes at end of table.)

Table 7.2 Continued

Trace Metal	PM Control Device	Sources*	Detects	Min.	Max.	Median	Mean	Std. Dev.	UPL**
Mercury	ESP/Fabric Filter	8	7	3.22E-07	2.87E-06	4.02E-07	8.63E-07	8.09E-07	2.91E-06
Mercury	Mechanical Collector	7,3	2	5.00E-07	2.23E-06	5.00E-07	1.08E-06	9.99E-07	2.72E-06
Mercury	Wet Scrubber	8,7	7	8.85E-13	1.85E-06	6.61E-07	6.68E-07	5.85E-07	1.63E-06
Molybdenum	Fabric Filter	2	2	1.13E-06	3.01E-06	2.07E-06	2.07E-06	--	--
Nickel	ESP/Fabric Filter	5	4	1.22E-06	3.77E-06	3.45E-06	2.66E-06	1.18E-06	5.75E-06
Nickel	Mechanical Collector	10	10	2.33E-08	2.62E-04	2.26E-05	6.16E-05	8.32E-05	2.69E-04
Nickel	Wet Scrubber	8	8	2.97E-12	6.34E-05	3.94E-06	1.38E-05	2.21E-05	6.95E-05
Phosphorus	Fabric Filter	1	1	--	--	1.93E-05	1.93E-05	--	--
Phosphorus	Wet Scrubber	2	2	3.54E-05	1.6E-04	9.85E-05	9.85E-05	--	--
Potassium	Fabric Filter	1	1	--	--	3.88E-02	3.88E-02	--	--
Selenium	ESP/Fabric Filter	5	3	4.59E-07	6.50E-06	5.11E-07	1.69E-06	2.41E-06	7.96E-06
Selenium	Mechanical Collector	8	5	1.37E-09	3.61E-05	2.53E-06	7.65E-06	1.13E-05	2.63E-05
Selenium	Wet Scrubber	5,3	2	<4.61E-12	2.34E-06	1.85E-06	1.40E-06	1.43E-06	3.75E-06
Silver	Mechanical Collector	2	2	1.39E-04	1.7E-03	9.37E-04	9.37E-04	--	--
Silver	Wet Scrubber	2	2	1.20E-07	1.9E-06	9.85E-07	9.85E-07	--	--
Sodium	Fabric Filter	1	1	--	--	3.63E-04	3.63E-04	--	--
Strontium	Fabric Filter	1	1	--	--	1.01E-05	1.01E-05	--	--
Thallium	Wet Scrubber	1	1	--	--	1.85E-06	1.85E-06	--	--
Tin	Fabric Filter	1	1	--	--	3.91E-05	3.91E-05	--	--
Titanium	Fabric Filter	1	1	--	--	2.01E-05	2.01E-05	--	--
Vanadium	Fabric Filter	1	1	--	--	5.94E-07	5.94E-07	--	--
Yttrium	Fabric Filter	1	1	--	--	3.01E-07	3.01E-07	--	--
Zinc	ESP/Fabric Filter	9	9	1.67E-05	7.09E-04	4.38E-05	1.30E-04	2.22E-04	6.87E-04
Zinc	Mechanical Collector	9	9	2.11E-06	7.83E-03	2.94E-04	1.35E-03	2.48E-03	7.58E-03
Zinc	Wet Scrubber	6	6	3.11E-10	2.78E-03	2.50E-04	6.58E-04	1.07E-03	3.40E-03

*If this column has two entries, the 1st entry represents the total number of sources that were tested and the 2nd entry represents the sources for which data were included in the analysis for estimating averages; the difference represents sources whose data were rejected mainly because they yielded non-detects with detection limits exceeding the highest detected observation. Occasionally, an observation confirmed to be a statistical outlier was also rejected.

** UPL=upper prediction limit. Estimated using mean + 1.65 x std. dev. for normally distributed data and the Chebyshev Inequality with 85% confidence coefficient for non-normally distributed data.

[a] Modified Kaplan-Meier median - 50 percentile value obtained from best curve fit of the quantiles generated by the K-M subroutine. [b] See Section 7.2 for further discussion.

APPENDIX B

VENDOR SPECIFICATIONS FOR UPGRADED DUST COLLECTOR

Date: July 14, 2010

Mechanical Dust Collector Performance Guaranty And Warranty

Reference Process Equipment Quote: **50114 Rev. G**
Reference Customer Inquiry/Job: **Georgia Pacific-#4 Combo Boiler (Palatka, FL)**

Process Equipment warrants that the dust collector will perform at the given efficiencies and pressure drops when operated per the corresponding conditions listed below and in the proposal referenced above.

Particulate Emissions:
Process Equipment guarantees that the multiclone dust collector will collect 84.06% (+/- 5%) at 2.0 gr/acf and 78.96% (+/- 5%) at .5gr/acf of the particulate, based on:

- The particulate distribution being 50% less than 27 microns, 84.1% less than 90 microns-
- The particulate has a 2.2 SG (specific gravity) or greater-
- The collector is operated at the design volumetric flow rate and temperature-

Pressure Drop:
Process Equipment guarantees the multiclone dust collector will operate at the design pressure drop (+/- 0.5" W.C.) provided the collector is operated at the design volumetric flow rate and temperature.

To achieve the warranted performance, the following requirements must be met:

1. All dust collector components are properly maintained.
2. All hoppers, valves, and casings are operated free of any air leakage.
3. The ash removal system is properly maintained and operated continuously to allow the hoppers to be properly evacuated of any material accumulation.
4. Gas and dust entering the collector are uniformly distributed over the inlet.
5. The dust particle size, specific gravity and loading are as set forth above.
6. The boiler fuel consistency remains unchanged from its existing normal consistency.
7. The boiler operation will be consistent with the manner in which the boiler was originally designed or is presently being operated.

Process Equipment assumes no liability for any special indirect, or consequential damages of any nature, nor shall any be imposed based on its undertaking herein. Process Equipment's limit of liability, in every case, shall be no greater than 10% the sale price of the dust collector for which the warranty was originally given.

Process Equipment will assist Purchaser with the correction of system related problems, at the sole expense of the Purchaser. Unless agreed to in writing, the cost of all testing shall be paid by the Purchaser.

P. O. Box 1607, Pelham, AL 35124 • Phone: 205-663-5330 • Fax: 205-663-6037 • http://www.process-equip.com

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