Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

June 9, 2005

Mr. Gregg M. Worley, Chief
Air Permits Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303-8960

RE: Georgia-Pacific Corporation
Palatka Mill
1070005-033-AC, PSD-FL-357

Dear Mr. Worley:

Enclosed for your review and comment is a PSD application submitted by Georgia-Pacific Corporation for a modification to the No. 4 combination boiler at their Palatka Mill in Putnam County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Bruce Mitchell, review engineer, at 850/413-9198.

Sincerely,

Patty Adams

for Jeffrey F. Koerner, P.E., Administrator
North Permitting Section

JFK/pa

Enclosure

cc: B. Mitchell

From: DEP AIR RESOURCE MGMT
P. Adams
DIRECTOR OFFICE STE 23
111 S MAGNOLIADR
TALLAHASSEE, FL 32301
UNITED STATES Tel:850-921-9505

To: DEP Northeast District Office
Mr. Chris Kirts
7825 Baymeadows Way
Air Section, Suite 200B
Jacksonville, FL 32256
UNITED STATES

Tel: 904-807-3235

EXP

Parcels: 1/1

ORIGIN: TLH

Sender's ref 37550201000 A7 AP255

POSTCODE: 32256

Description: PSD-FL-357 application

Weight: 3 lbs for 1 pcs
Date: 2005-06-10

DHL standard terms and conditions apply.

ASHX 5Y
FSC

(2L)US32256

WAYBILL: 26623778554 (Non-Negotiable)

PEEL HERE PEEL HERE

Please fold or cut in half

DO NOT PHOTOCOPY

Using a photocopy could delay the delivery of your package and will result in additional shipping charge

SENDER'S RECEIPT
Waybill #: 26623778554

To(Company):
DEP Northeast District Office
Air Section, Suite 200B
7825 Baymeadows Way

Jacksonville, FL 32256
UNITED STATES

Attention To: Mr. Chris Kirts
Phone#: 904-807-3235

Sent By: P. Adams
Phone#: 850-921-9505

Rate Estimate: 6
Protection: Not Required
Description: PSD-FL-357 application

Weight (lbs.): 3
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: Next Day 12:00 (Next business day by 12 PM)

Special Svc:

Date Printed: 6/10/2005
Bill Shipment To: Sender
Bill To Acct: 778941266

DHL Signature (optional) ____________ Route ______ Date ______ Time ______

For Tracking, please go to www.dhl-usa.com or call 1-800-225-5345
Thank you for shipping with DHL

Create new shipment ▸ View pending shipments Print waybill

DHL EXPRESS

From: DEP AIR RESOURCE MGMT
P. Adams
DIRECTOR OFFICE STE 23
111 S MAGNOLIA DR
TALLAHASSEE, FL 32301
UNITED STATES Tel:850-921-9505

To: U.S. EPA Region 4
Mr. Gregg M. Worley
61 Forsyth Street
Air Permits Section
Atlanta, GA 30303
UNITED STATES

2ND

Parcels: 1/1

ORIGIN: TLH

Sender's ref 37550201000 A7 AP255

POSTCODE: 30303

Tel: 404-562-9141

Description: books

Weight: 4 lbs for 1 pcs
Date: 2005-06-09

DHL standard terms and conditions apply.

Day 13MO

HARB 6V
ATT

(2L)US30303

WAYBILL: 26607314554 (Non-Negotiable)

▲ PEEL HERE PEEL HERE ▲

Please fold or cut in half

DO NOT PHOTOCOPY

Using a photocopy could delay the delivery of your package and will result in additional shipping charge

SENDER'S RECEIPT
Waybill #: 26607314554

To(Company):
U.S. EPA Region 4
Air Permits Section
61 Forsyth Street

Atlanta, GA 30303
UNITED STATES

Attention To: Mr. Gregg M. Worley
Phone#: 404-562-9141

Sent By: P. Adams
Phone#: 850-921-9505

Rate Estimate: 3.25
Protection: Not Required
Description: books

Weight (lbs.): 4
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: 2nd Day (2nd business day by 5 PM)

Special Svc:

Date Printed: 6/9/2005
Bill Shipment To: Sender
Bill To Acct: 778941286

DHL Signature (optional) ______________ Route ______ Date ______ Time ______

For Tracking, please go to www.dhl-usa.com or call 1-800-225-5345
Thank you for shipping with DHL

Create new shipment ▶ View pending shipments Print waybill

DHL EXPRESS

DHL

2ND

Parcels: 1/1

From: DEP AIR RESOURCE MGMT
P. Adams
DIRECTOR OFFICE STE 23
111 S MAGNOLIA DR
TALLAHASSEE, FL 32301
UNITED STATES Tel:850-921-9505

Origin: TLH

Sender's ref: 37550201000 A7 AP255

To: National Park Service
Mr. John Bunyak
12795 W. Alameda Parkway
Air Division
Lakewood, CO 80228
UNITED STATES

Tel: 303-966-2818

POSTCODE: 80228

Day 13MO

Description: books

Weight: 4 lbs for 1 pcs
Date: 2005-06-09

DHL standard terms and conditions apply.

EGEH 8E
OOH

(2L)US80228

WAYBILL: 26607181053

(Non-Negotiable)

▲ PEEL HERE — PEEL HERE ▲

Please fold or cut in half

DO NOT PHOTOCOPY

Using a photocopy could delay the delivery of your package and will result in additional shipping charge

SENDER'S RECEIPT

Waybill #:	26607181053	Rate Estimate:	6.57
		Protection:	Not Required
To(Company):	National Park Service, Air Division, 12795 W. Alameda Parkway, Lakewood, CO 80228, UNITED STATES	Description:	books
		Weight (lbs.):	4
		Dimensions:	0 x 0 x 0
		Ship Ref:	37550201000 A7 AP255
Attention To:	Mr. John Bunyak	Service Level:	2nd Day (2nd business day by 5 PM)
Phone#:	303-966-2818	Special Svc:	
Sent By:	P. Adams	Date Printed:	6/9/2005
Phone#:	850-921-9505	Bill Shipment To:	Sender
		Bill To Acct:	778941286

DHL Signature (optional) ____________ Route ______ Date ______ Time ______

For Tracking, please go to www.dhl-usa.com or call 1-800-225-5345

Thank you for shipping with DHL

Create new shipment ▶ View pending shipments **Print waybill**

DHL EXPRESS

Georgia-Pacific

Palatka Pulp and Paper Operations
Consumer Products Division

P.O. Box 919
Palatka, FL 32178-0919
(386) 325-2001

May 27, 2005

Ms. Trina Vielhauer
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
Division of Air Resource Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Ms. Vielhauer:

RE: Georgia-Pacific, Palatka Operations
PSD Application – No. 4 Combination Boiler Modification

Dear Ms. Vielhauer:

Please find enclosed seven (7) copies of the PSD Application for the No. 4 Combination Boiler Modification and also a check in the amount of $7,500.

If further information is needed, please contact me at (386) 329-0918.

Sincerely,

Myra J. Carpenter

Myra J. Carpenter
Environmental Superintendent

tk

Enclosure

cc: W. M. Jernigan, w/o enc.
Scott Matchett, w/o enc.

RECEIVED

JUN 03 2005

BUREAU OF AIR REGULATION

PSD APPLICATION FOR THE NO. 4 COMBINATION BOILER MODIFICATION

GEORGIA-PACIFIC CORPORATION
PALATKA MILL

Prepared For:
Georgia-Pacific Corporation
P.O. Box 919
Palatka, Florida 32178

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

April 2005

0437578

DISTRIBUTION:
7 Copies – FDEP
5 Copies – GP
2 Copies – Golder Associates Inc.

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

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

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

To ensure accuracy, please see form instructions.

Identification of Facility

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

Application Contact

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

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	6-3-05
2. Project Number(s):	1070005-033-AC
3. PSD Number (if applicable):	PSD-FL-357
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

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

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

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

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

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

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

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

Application Comment

This application is for the implementation of physical changes to the No. 4 Combination Boiler to allow the increased firing of bark/wood in the boiler.

APPLICATION INFORMATION

Scope of Application

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

Application Processing Fee

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

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1. Owner/Authorized Representative Name :

   Theodore D. Kennedy, Vice President, Georgia-Pacific, Palatka Operations

2. Owner/Authorized Representative Mailing Address...

   Organization/Firm: **Georgia-Pacific Corporation**

   Street Address: **P.O. Box 919**

   City: **Palatka** State: **FL** Zip Code: **32178**

3. Owner/Authorized Representative Telephone Numbers...

   Telephone: **(386) 325-2001** ext. Fax: **(386) 328-0014**

4. Owner/Authorized Representative Email Address: **Ted.Kennedy@gapac.com**

5. Owner/Authorized Representative Statement:

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

   Theodore D Kennedy 5/27/05
   Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification

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

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

APPLICATION INFORMATION

Professional Engineer Certification

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

5. Professional Engineer Statement:

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

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

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

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

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

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

David A. Buff — 5/25/05

Signature — Date

(seal)

* Attach any exception to certification statement.

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

APPLICATION INFORMATION

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **434.0** North (km) **3283.4**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **29/41/0** Longitude (DD/MM/SS) **81/40/45**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **26**	6. Facility SIC(s): **2611, 2621**
7. Facility Comment :			

Facility Contact

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

Facility Primary Responsible Official

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

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

APPLICATION INFORMATION

Facility Regulatory Classifications

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

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

APPLICATION INFORMATION

List of Pollutants Emitted by Facility

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

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

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

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID:**GP-FI-C1** ☐ Previously Submitted, Date:_____
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID:**GP-FI-C2** ☐ Previously Submitted, Date:_____
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID:**PSD Report** ☐ 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 or Modification: ☒ Attached, Document ID:**PSD Report**
3. Rule Applicability Analysis: ☒ Attached, Document ID:**PSD Report**
4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable
6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable
7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable

APPLICATION INFORMATION

Additional Requirements for FESOP Applications

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

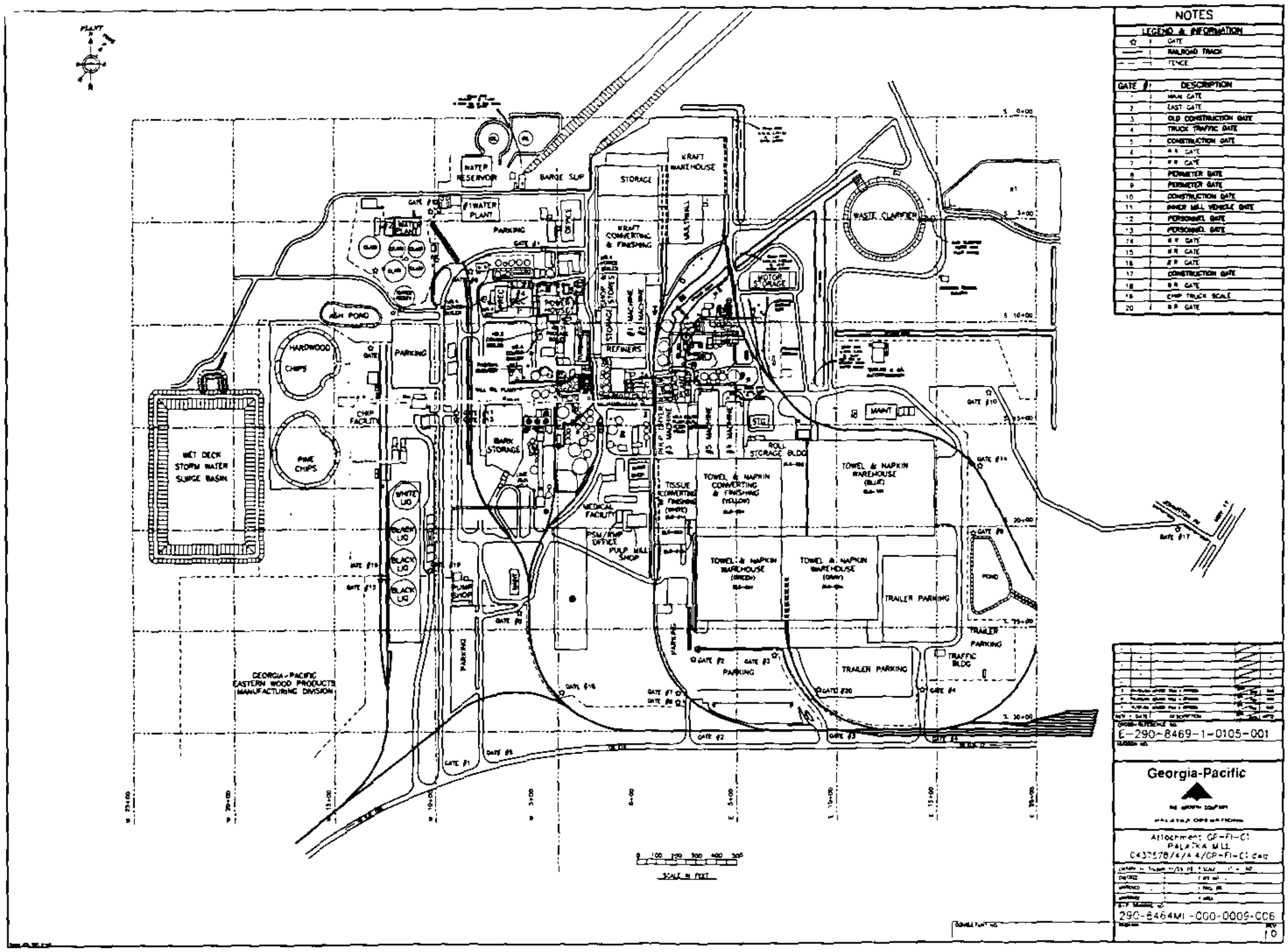
Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

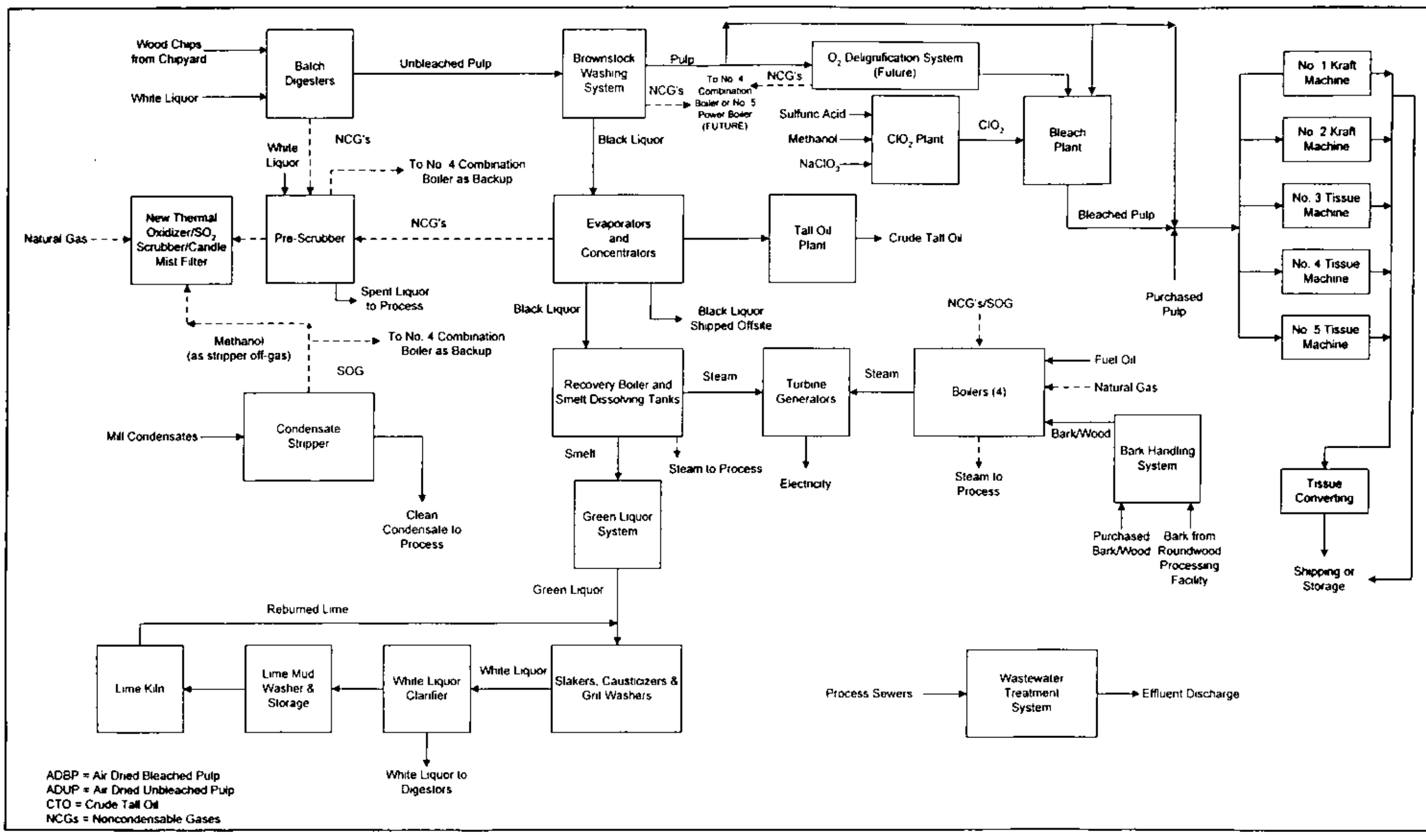
ATTACHMENT GP-FI-C1

FACILITY PLOT PLAN


NOTES
LEGEND & INFORMATION
GATE
RAILROAD TRACK
FENCE
GATE # DESCRIPTION
1 MAIN GATE
2 EAST GATE
3 OLD CONSTRUCTION GATE
4 TRUCK TRAFFIC GATE
5 CONSTRUCTION GATE
6 R.R. GATE
7 R.R. GATE
8 PERIMETER GATE
9 PERIMETER GATE
10 CONSTRUCTION GATE
11 INNER MILL VEHICLE GATE
12 PERSONNEL GATE
13 PERSONNEL GATE
14 R.R. GATE
15 R.R. GATE
16 R.R. GATE
17 CONSTRUCTION GATE
18 R.R. GATE
19 CHIP TRUCK SCALE
20 R.R. GATE
WATER RESERVOIR
BARGE SLIP
STORAGE
KRAFT WAREHOUSE
KRAFT CONVERTING & FINISHING
MULTIWALL
WASTE CLARIFIER
MOTOR STORAGE
#1 WATER PLANT
PARKING
ASH POND
HARDWOOD CHIPS
PINE CHIPS
WET DECK STORM WATER SURGE BASIN
CHIP FACILITY
BARK STORAGE
REFINERS
WHITE LIQ
BLACK LIQ
BLACK LIQ
BLACK LIQ
PUMP SHOP
MEDICAL FACILITY
PSM/RMP OFFICE
PULP MILL SHOP
TISSUE CONVERTING & FINISHING
ROLL STORAGE BLDG
MAINT
TOWEL & NAPKIN CONVERTING & FINISHING (YELLOW)
TOWEL & NAPKIN WAREHOUSE (BLUE)
TOWEL & NAPKIN WAREHOUSE (GREEN)
TOWEL & NAPKIN WAREHOUSE (GRAY)
TRAILER PARKING
TRAILER PARKING
TRAFFIC BLDG
POND
GEORGIA-PACIFIC EASTERN WOOD PRODUCTS MANUFACTURING DIVISION
SCALE IN FEET
E-290-8469-1-0105-001
Georgia-Pacific
Attachment GP-FI-C1
PALATKA MILL
0437578/4/4.4/GP-FI-C1.dwg
290-8464MI-000-0009-C06
10

ATTACHMENT GP-FI-C2

PROCESS FLOW DIAGRAM



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

Process Flow Legend

Solid/Liquid ——→
Gas - - - - →

Filename 0437578/4/4.4/GP-FI-C2.VSD
Date 5/25/05

Golder Associates

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.) ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit. ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one) ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent). ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions. ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.				
2. Description of Emissions Unit Addressed in this Section: **No. 4 Combination Boiler (EU 016)**				
3. Emissions Unit Identification Number: **016**				
4. Emissions Unit Status Code: **A**	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: **26**	8. Acid Rain Unit? ☐ Yes ☒ No
9. Package Unit: Manufacturer: Model Number:				
10. Generator Nameplate Rating: MW				
11. Emissions Unit Comment: **Dilute Non-condensable Gases (DNCGs) from the future Brown Stock Washing System and the O_2 Delignification System sources will be routed to the No. 4 Combination Boiler or the No. 5 Power Boiler for TRS and HAP destruction as the primary control device.**				

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Centrifugal Collector** **Electrostatic Precipitator**
2. Control Device or Method Code(s): **007, 010**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:			
2. Maximum Production Rate:			
3. Maximum Heat Input Rate: 512.7 million Btu/hr			
4. Maximum Incineration Rate:	pounds/hr tons/day		
5. Requested Maximum Operating Schedule:			
	24 hours/day		7 days/week
	52 weeks/year		8,760 hours/year
6. Operating Capacity/Schedule Comment: Maximum heat input rate is based on firing bark/wood only or in combination with No. 6 fuel oil. Maximum heat input rate shall not be exceeded as a 24-hour average. The maximum heat input rate on an annual basis is synthetically limited to 4,042,127 MMBtu/yr. Natural gas is used as a start-up fuel.			

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

Emission Point Description and Type

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

5. Discharge Type Code: **V**	6. Stack Height: **237** feet	7. Exit Diameter: **8** feet
8. Exit Temperature: **466** °F	9. Actual Volumetric Flow Rate: **278,400** acfm	10. Water Vapor: **20** %

11. Maximum Dry Standard Flow Rate: **135,400** dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack data based on actual stack testing. The dscfm is corrected to 10-percent O_2.**	

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

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Wood/Bark**		
2. Source Classification Code (SCC): **1-02-009-02**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **57.0**	5. Maximum Annual Rate: **449,125**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **9**
10. Segment Comment: **Maximum hourly rate is based on maximum 24-hr average of 512.7 MMBtu/hr and 4,500 Btu/lb (bark/wood).** **Hourly: 512.7 MMBtu/hr x 1 lb/4,500 Btu x 1 ton/2,000 lbs = 57.0 TPH** **Annual: Based on 4,042,127 MMBtu/yr, which is GP's proposed maximum annual rate. 4,042,127 MMBtu/yr x 1 lb/4,500 Btu x 1 ton/2,000 lbs = 449,125 TPY**		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Residual Oil; Grade 6 Oil**		
2. Source Classification Code (SCC): **1-02-004-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **2.791**	5. Maximum Annual Rate: **5,300**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2.35**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
10. Segment Comment: **Maximum 24-hour: 418.6 MMBtu/hr x 1 gal/150,000 Btu = 2,791 gal/hr (max. 24-hour avg.)** **Annual: Limited to 5,300,000 gal/yr as proposed permit condition.** **Residual oil may include No. 6 fuel oil and on-spec used oil.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Natural Gas; >100 MMBtu**		
2. Source Classification Code (SCC): **1-02-006-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,020**
10. Segment Comment: **Natural gas used as a start-up fuel.**		

Segment Description and Rate: Segment _____ of _____

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

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	007	010	EL
PM_{10}	007	010	NS
SO_2			EL
NO_x			NS
CO			NS
VOC			NS
HAPs			NS
H095 (Formaldehyde)			NS
H106 (Hydrochloric Acid)			NS
H115 (Methanol)			NS
TRS			EL

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **35.9** lb/hour **141.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.07 lbs/MMBtu** Reference: **Proposed Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Max. Hourly: Due to wood/bark firing –** **512.7 MMBtu/hr x 0.07 lbs/MMBtu = 35.9 lbs/hr** **Max. Annual: Due to wood/bark firing –** **4,042,127 MMBtu/yr x 0.07 lbs/MMBtu x ton/2,000 lbs = 141.47 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Maximum emissions based on bark/wood firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MMBtu/yr, representing 90-percent capacity factor.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.07 lbs/MMBtu**	4. Equivalent Allowable Emissions: **35.9** lb/hour **141.5** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Proposed limit for bark/wood firing.** **Hourly: 512.7 MMBtu/hr x 0.07 lbs/MMBtu = 35.9 lbs/hr** **Annual: 4,042,127 MMBtu/yr x 0.07 lbs/MMBtu x ton/2,000 lbs = 141.47 TPY**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.07 lbs/MMBtu**	4. Equivalent Allowable Emissions: **29.3** lb/hour **27.8** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Proposed limit for No. 6 fuel oil firing. Hourly emissions based on: 418.6 MMBtu/hr x 0.07 lbs/MMBtu = 29.3 lbs/hr** **Annual fuel oil firing limit based on: 795,000 MMBtu/yr x 0.07 lbs/MMBtu x ton/2,000 lbs = 27.8 TPY**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **26.6** lb/hour **104.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **74 % of PM** Reference: **AP-42, Table 1.6-1**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Max. Hourly: 35.9 lbs/hr PM x 0.74 = 26.6 lbs/hr** **Max. Annual: 141.47 TPY PM x 0.74 = 104.7 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Maximum emissions based on bark/wood firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MMBtu/yr, representing 90-percent capacity factor.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2,117.2** lb/hour **1,846.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2.35% Sulfur** Reference: **Permit Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Maximum daily emissions are 1,921.4 lbs/hr SO_2 (24-hr average).** **Refer to Attachment GP-EU1-F1.8.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Refer to Attachment GP-EU1-F1.8. Emissions synthetically liimited due to annual limit on fuel oil firing (5.3 million gal/yr) and limit on sulfur content (2.35% S).**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.35% Sulfur**	4. Equivalent Allowable Emissions: **1,075.7** lb/hour **1,021.3** tons/year
5. Method of Compliance: **Fuel Analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Proposed permit limit for fuel oil firing only. Annual fuel oil firing limited to 5,300,000 gal/yr.** **5,300,000 gal/yr x 8.2 lbs/gal x 0.0235 lbs S/lb oil x 2 lbs SO_2/lb S x ton/2,000 lbs = 1,021.3 TPY** **418.6 MMBtu/hr x gal/150,000 Btu x 8.2 lbs/gal x 0.0235 lbs S/lb oil x 2 lbs SO_2/lb S = 1,075.7 lbs/hr**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **958.9 lb/hr**	4. Equivalent Allowable Emissions: **958.9** lb/hour **548.7** tons/year
5. Method of Compliance: **Tracking of time and pulp production during which LVHC (NCGs)/SOGs are burned. LVHC/SOGs burning limited to maximum of 548.7 TPY SO_2.**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions reflect LVHC (NCG)/SOG burning only. Hourly emissions based on 462.9 lbs/hr from LVHC NCG burning and 496.0 lbs/hr from SOG burning.** **Refer to Attachment GP-EU1-F1.8.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **82.6 lb/hr**	4. Equivalent Allowable Emissions: **82.6** lb/hour **236.3** tons/year
5. Method of Compliance: **Tracking of time during which HVLC (dilute NCGs) are burned. HVLC burning time allowed for 8,760 hr/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions reflect HVLC (dilute NCGs) burning only.** **118 TPH ADUP x 0.35 lbs S/ton ADUP x 2 lbs SO_2/lb S = 82.6 lbs/hr** **675,250 TYP ADUP x 0.35 lbs S/ton ADUP x 2 lbs SO_2/lb S x ton/2,000 lbs = 236.3 TPY**	

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

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

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

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **166.2** lb/hour **522.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.24 lb/MMBtu for bark/wood** Reference: **Proposed limit**	7. Emissions Method Code: **0**

8. Calculation of Emissions:

Hourly: Wood/Bark - 512.7 MMBtu/hr x 0.24 lbs/MMBtu = 123.05 lbs/hr
SOGs – 0.9 lbs NO_x/1,000 gal condensate x 48,000 gal/hr condensate = 43.2 lbs/hr
Total – 123.05 + 43.2 = 166.2 lbs/hr

Annual: Wood/Bark – 4,042,127 MMBtu/yr x 0.24 lbs/MMBtu x ton/2,000 lbs = 485.06 TPY
SOGs – Burned up to 20% of the time: 43.2 lbs/hr x 8,760 hr/yr x 0.20 x ton/2,000 lbs = 37.84 TPY
Total – 485.06 + 37.84 = 522.9 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Maximum annual emissions based on maximum bark/wood burning of 4,042,127 MMBtu/yr (485.06 TPY NO_x) plus NO_x due to SOG burning of 37.84 TPY. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MMBtu/yr, representing 90%-capacity factor.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.24 lbs/MMBtu for bark/wood**	4. Equivalent Allowable Emissions: **123.1** lb/hour **485.1** tons/year
5. Method of Compliance: **EPA Method 7 or 7E.**	
6. Allowable Emissions Comment (Description of Operating Method): **Proposed limit for bark/wood firing only. See Section F1 and Appendix A of Part B for calculations.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.2 lbs/MMBtu for oil**	4. Equivalent Allowable Emissions: **83.7** lb/hour **79.5** tons/year
5. Method of Compliance: **EPA Method 7 or 7E.**	
6. Allowable Emissions Comment (Description of Operating Method): **Proposed limit for oil firing only:** **Hourly: 418.6 MMBtu/hr x 0.20 lbs/MMBtu = 83.72 lbs/hr** **Annual: 5,300,000 gal/yr x 150,000 Btu/gal x 0.20 lbs/MMBtu x ton/2,000 lbs = 79.50 TPY**	

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **307.6** lb/hour **1,212.6** 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** Reference: **AP-42, Table 1.6-2**	7. Emissions Method Code: **3**
8. Calculation of Emissions: **Max. Hourly: Due to wood/bark firing –** **512.7 MMBtu/hr x 0.60 lbs/MMBtu = 307.62 lbs/hr** **Max. Annual: Due to wood/bark firing –** **4,042,127 MMBtu/yr x 0.60 lbs/MMBtu x ton/2,000 lbs = 1,212.6 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Emission factor shown is for bark/wood firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MMBtu/yr, representing 90%-capacity factor.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.7** lb/hour **34.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.017 lb/MMBtu** Reference: **AP-42, Table 1.6-4**	7. Emissions Method Code: **3**

8. Calculation of Emissions:

Max. Hourly: Due to wood/bark firing –
512.7 MMBtu/hr x 0.017 lbs/MMBtu = 8.72 lbs/hr
Max. Annual: Due to wood/bark firing –
4,042,127 MMBtu/yr x 0.017 lbs/MMBtu x ton/2,000 lbs = 34.4 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Emission factor shown is for bark/wood firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MMBtu/yr, representing 90%-capacity factor.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

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

8. Calculation of Emissions:

Hourly: **5 ppmvd/10^6 x (14.7 x 144) (lb/ft^2) x 135,400 dscfm x 60 min/hr x (34 lb_m/lb-mole)/(1,545.6 ft-lb_f/lb-mole -°R) x 1/528°R = 3.6 lbs/hr**
Annual: **3.6 lbs/hr x 8,760 hr/yr x 1 ton/2,000 lbs = 15.7 TPY**

TRS reported as H_2S.

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Based on usage of the No. 4 Combination Boiler as a backup combustion device for LVHC gas stream, and as the primary combustion device for the HVLC gas stream.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5 ppmvd @10% O_2**	4. Equivalent Allowable Emissions: **3.6** lb/hour **15.7** tons/year
5. Method of Compliance: **Maintain minimum temperature of 1,200°F and the 0.5-second residence time as required by rule.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.404(3)(f)1 and Permit No. 1070005-017-AC.**	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE30**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **30** % Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **Annual test using EPA Method 9.**	
5. Visible Emissions Comment: **Permit No. 1070005-017-AC. Applies to carbonaceous fuel burning only, or to carbonaceous fuel combined with fuel oil.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor ____ of ____

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

Continuous Monitoring System: Continuous Monitor ____ of ____

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

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

Additional Requirements for Air Construction Permit Applications

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

Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

ATTACHMENT GP-EU1-F1.8

CALCULATION OF EMISSIONS

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

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

(Refer to ATTACHMENT GP-EU1-F8a)

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

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

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

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

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

Conversion of sulfur to SO_2:

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

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

B. STRIPPER OFF-GASES (SOGs)

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

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

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

SOGs do not go through pre-scrubber.

C. FUEL OIL FIRING

Based on 2.35% sulfur fuel oil.

418.6 MMBtu/hr x 1 gal/150,000 Btu x 8.2 lbs/gal x 0.0235 lbs S/lbs oil x 2 lbs SO_2/lb S = 1,075.7 lbs/hr

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

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

Based on 118 TPH ADUP pulp production rate:

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

E. TOTAL

Total Hourly: 462.9 lbs/hr + 496.0 lbs/hr + 1,075.7 lbs/hr + 82.6 lbs/hr = 2,117.2 lbs/hr

2. MAXIMUM 24-HOUR SO_2 EMISSION RATE

(Refer to ATTACHMENT GP-EU1-F8b)

A. LVHC NCGs

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

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

Conversion of sulfur to SO_2:

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

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

B. SOGs

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

SOGs do not go through pre-scrubber.

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

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

C. FUEL OIL FIRING

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

1,075.5 lbs/hr SO_2 x 24 hrs/day = 25,813 lbs/day SO_2

D. HVLC DNCGs

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

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

E. TOTAL

Total 24-Hour: 9,023 lbs/day + 9,668 lbs/day + 25,813.0 lbs/day + 1,610.0 lbs/day = 46,113 lbs/day

24-hour average = 46,113 lbs/day ÷ 24 hrs/day = 1,921.4 lbs/hr SO_2

3. MAXIMUM ANNUAL SO_2 EMISSION RATE

(Refer to ATTACHMENT GP-EU1-F8c)

A. LVHC NCGs

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

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

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

Conversion of sulfur to SO_2:

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

B. SOGs

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

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

SOGs do not go through pre-scrubber.

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

C. FUEL OIL FIRING

Annual fuel oil firing limited to 5,300,000 gal/yr or 795,000 MMBtu/yr.

5,300,000 gal/yr x 8.2 lbs/gal x 0.0235 lbs S/lb oil x 2 lbs SO_2/lb S x 1 ton/2,000 lbs = 1,021.3 TPY SO_2.

D. HVLC DNCGs

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

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

E. BARK/WOOD FIRING

Heat input to boiler limited to 4,042,127 MMBtu/yr. Total fuel oil limited to 795,000 MMBtu/yr

Therefore, remainder of heat input due to bark/wood = 4,042,127 – 795,000 = 3,247,127 MMBtu/yr

SO_2 Emission factor = 0.025 lb/MMBtu

3,247,127 MMBtu/yr x 0.025 lb/MMBtu x ton/2,000 lb = 40.59 TPY SO_2

F. TOTAL

Total Annual: 264.9 TPY + 283.8 TPY + 1,021.3 TPY + 236.3 TPY + 40.59 = 1,846.9 TPY SO_2.

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

Attachment GP-EU1-F1.8a. Calculation of Maximum Hourly SO_2 Emissions From No. 4 Combination Boiler

Source	Maximum Pulp Production (TPH ADUP)	Uncontrolled TRS Emissions lbs S/hr[a]	Uncontrolled TRS Emissions lbs S/ton ADUP[b]	Potential Uncontrolled SO_2 Emissions (lbs/hr)	Pre-scrubber Sulfur Removal Efficiency (%)	Maximum SO_2 Emission Rate[c] (lbs/hr)
FUEL OIL COMBUSTION						
Permitted No. 6 Fuel Oil Burning @ 2.35% S	--	--	--	1,075.7 [d]	--	1,075.7
LVHC/SOG DESTRUCTION						
LVHC NCGs	118	578.6	--	1,157.3	60 [e]	462.9
Condensate Stripper Off-Gas	118	248.0	--	496.0	0	496.0
Subtotal	118	826.6	--	1,653.3		958.9
HVLC DESTRUCTION						
HVLC DNCGs	118	--	0.35	82.6	--	82.6
					TOTALS	2,117.2

Note:

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

Footnotes:

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

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

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

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

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

Attachment GP-EU1-F1.8b. Calculation of Maximum 24-Hour SO_2 Emissions From No. 4 Combination Boiler

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

Note:

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

Footnotes:

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

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

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

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

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

Attachment GP-EU1-F1.8c. Calculation of Maximum Annual SO_2 Emissions From No. 4 Combination Boiler

Source	Maximum Pulp Production (TPY ADUP)	Uncontrolled TRS Emissions lbs/hr[a]	Uncontrolled TRS Emissions lbs S/ton ADUP[b]	Potential Uncontrolled SO_2 Emissions (lbs/hr)	Pre-scrubber Sulfur Removal Efficiency (%)	Maximum SO_2 Emission Rate[c] (TPY)
FUEL OIL COMBUSTION						
Maximum No. 6 Fuel Oil Burning @ 2.35% S	--	--	--	--	--	1,021.3[d]
BARK/WOOD COMBUSTION						
Remainder of Heat Input	--	--	--	--	--	40.6[f]
LVHC/SOG DESTRUCTION @ 20% UPTIME						
LVHC NCGs	675,250	378.0	--	756.0	60[e]	264.9
Condensate Stripper Off-Gas	675,250	162.0	--	324.0	0	283.8
Subtotal	675,250	540.0	--	1,080.0		548.7
HVLC DESTRUCTION @ 100% UPTIME						
HVLC DNCGs	675,250	--	0.35	--	--	236.3
					TOTALS	1,846.9

Note:

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

Footnotes:

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

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

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

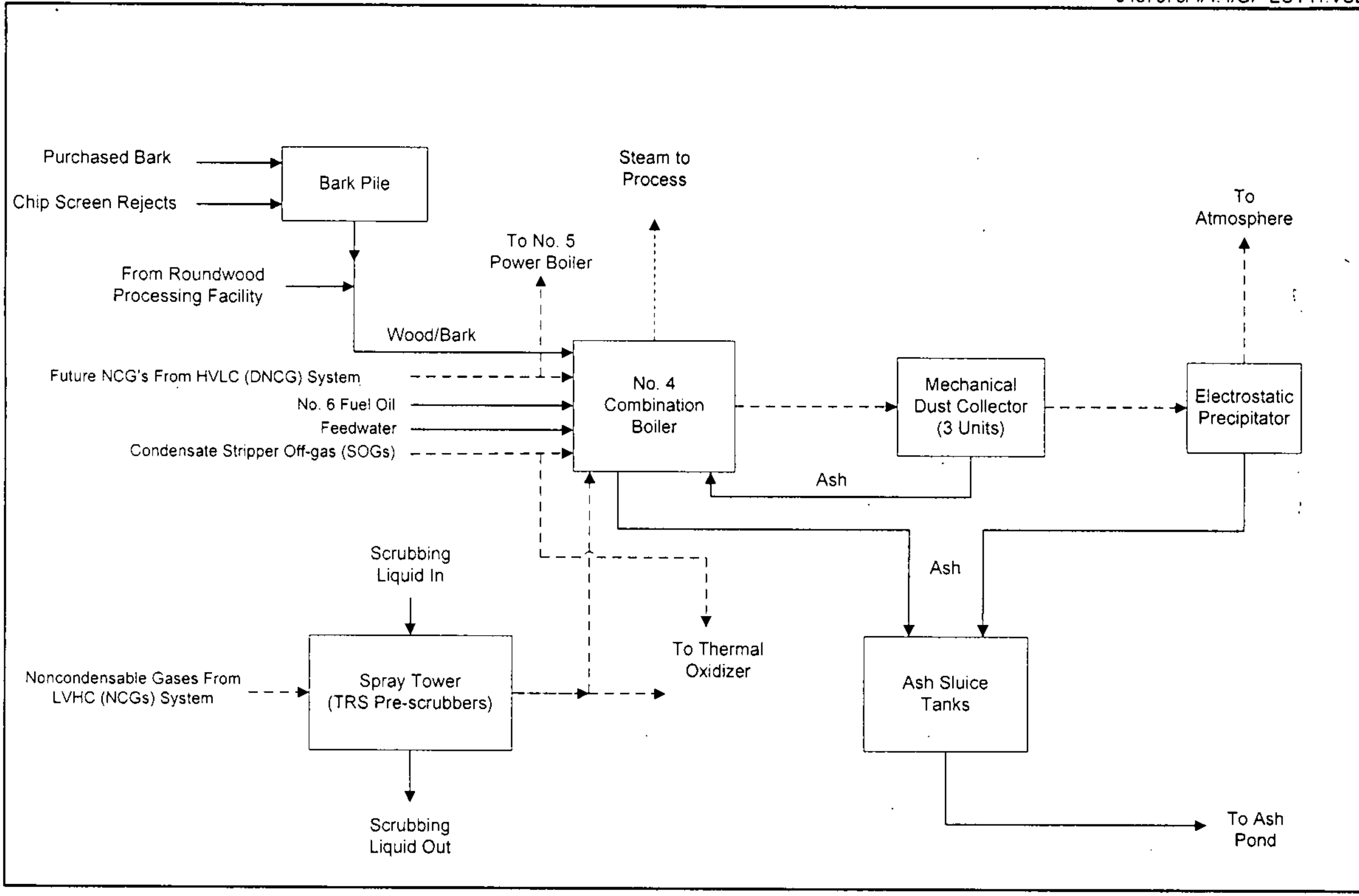
[d] Based on 5,300,000 gal/yr fuel oil usage; 150,000 Btu/gal; 2.35% sulfur; and the equation: SO_2 = gal oil x % S oil/100 x 8.2 lbs/gal x 2 lbs SO_2/lbs S.

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

[f] Based on total heat input to boiler (4,042,127 MMBtu/yr) minus maximum fuel oil input (795,000 MMBtu/yr) = 3,247,127 MMBtu/yr and AP-42 factor of 0.025 lb SO_2/MMBtu for wood/bark burning.

ATTACHMENT GP-EU1-I1

PROCESS FLOW DIAGRAM



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

Process Flow Legend

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

Filename: 0437578/4/4.4/GP-EU1-I1.VSD
Date: 05/25/05

Golder Associates

ATTACHMENT GP-EU1-I2

FUEL ANALYSIS

ATTACHMENT GP-EU1-I2

NO. 4 COMBINATION BOILER
FUEL ANALYSIS

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

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

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

ATTACHMENT GP-EU1-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

ATTACHMENT GP-EU1-I3

CONTROL EQUIPMENT
NO. 4 COMBINATION BOILER

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

Parameter	**Primary Dust Collector**	**Secondary Dust Collector**	**Tertiary Dust Collector**
Manufacturer	Zurn	Universal Oil Products Co.	Universal Oil Products Co.
Inlet Gas Temp	700°F	400°F	400°F
Inlet Gas Flow	280,000 ACFM	225,000 ACFM	225,000 ACFM
Pressure Drop	< 3 inches	3-4 inches	3-4 inches
Control Efficiency	80-90%	85-90%	85-90%

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

ATTACHMENT GP-EU1-I7

OTHER INFORMATION
REQUIRED BY RULE OR STATUTE

ATTACHMENT GP-EU1-I7

LIST OF APPLICABLE REGULATIONS

40 CFR 63, Subpart DDDDD – NESHAPs for Industrial Boilers

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

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

62-296.310–General Test Requirements

62-296.404(3)(f)–Kraft Pulp Mills

62-296.404(4)(e)–Kraft Pulp Mills

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

62-296.410(3)–Test Methods and Procedures

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

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

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

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

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

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

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

PSD REPORT

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LIST OF ACRONYMS AND ABBREVIATIONS

AAQS	Ambient Air Quality Standards
AOR	annual operating report
AQRV	air quality related value
ATP	adenosine triphosphate
BACT	Best Available Control Technology
Btu/gal	British thermal units per gallon
Btu/lb	British thermal units per pound
CAA	Clean Air Act
CFR	Code of Federal Regulations
CO	carbon monoxide
DAT	deposition analysis threshold
DNCG	dilute non-condensable gas
EPA	U.S. Environmental Protection Agency
F.A.C.	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
gal/hr	gallons per hour
g/s	grams per second
GEP	Good Engineering Practice
HNO_3	nitric acid
HSH	highest, second-highest
kg/ha/yr	kilograms per hectare per year
km	kilometer
lbs/hr	pounds per hour
MACT	Maximum Achievable Control Technology
MMBtu/hr	million British thermal units per hour
NCASI	National Council for Air and Stream Improvement, Inc.
NCG	non-condensable gas
NO_2	nitrogen dioxide
NO_3	nitric oxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards

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LIST OF ACRONYMS AND ABBREVIATIONS (cont'd)

NSR	new source review
NWA	National Wilderness Area
O_3	ozone
OFA	overfire air
PCP	pollution control project
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter equal to or less than 10 micrometers
ppm	parts per million
PSD	prevention of significant deterioration
RACT	Reasonably Available Control Technology
SAM	sulfuric acid mist
SIP	State Implementation Plan
SOG	stripper off gas
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SO_4	sulfate
SR	State Road
TPH	tons per hour
TPY	tons per year
TSP	total suspended particulates
UFA	underfire air
$\mu g/m^3$	micrograms per cubic meter
$\mu g/m^2/s$	micrograms per square meter per second
VE	visible emissions
VMT	vehicle miles traveled
VOC	volatile organic compound

1.0 INTRODUCTION

Georgia-Pacific Corporation (GP) is proposing changes to the No. 4 Combination Boiler at its Kraft pulp and paper mill located in Palatka, Putnam County, Florida. The GP Palatka Mill consists of the following major plant areas: chipyard, digester system, brown stock washing system, bleaching system, chemical recovery area, paper drying/converting/warehousing, and power/utilities area. The Mill is currently operating under Title V Permit No. 1070005-029-AV, issued February 7, 2005.

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

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

- Upgrading the bark/wood fuel delivery system by replacing worn out feed system parts, removing the existing bark bin, and modifying conveyors to accommodate these changes.
- Installing a bark/wood feed system, including a live bottom bark bin.
- Installing an underfire air (UFA) system in the Boiler.
- Upgrading an overfire air (OFA) system in the Boiler.
- Installing a new ash handling system to handle the increased ash generation rates.
- Installing new low-nitrogen oxides (NO_x) burners for fuel oil firing. The new burners will be of the same capacity and number as the existing burners.
- Improving operation of the electrostatic precipitator (ESP) used to control particulate emissions from the Boiler.

The bark/wood handling system will not be modified as part of this project.

Engineering evaluations are ongoing, and final engineering may dictate that some of these changes will be implemented, while others may not. The project will result in an increase in the actual amount of bark/wood fuel burned in the Boiler. However, the current permitted maximum bark/wood heat input and burning rate will not be increased as part of this project. The increase in the actual amount of bark/wood burned in the Boiler will offset fuel oil.

Based on the comparison of past actual annual emissions to future potential annual emissions from the No. 4 Combination Boiler, emission increases of carbon monoxide (CO) will trigger new source review (NSR) under the federal and State prevention of significant deterioration (PSD) regulations.

For each pollutant subject to PSD review, the following analyses are required:

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

This PSD permit application addresses these requirements and is organized into seven additional sections, followed by appendices. A description of the project, including air emission sources and pollution control equipment, is presented in Section 2.0. The regulatory applicability analysis for the proposed project is presented in Section 3.0. The required ambient air monitoring analysis is presented in Section 4.0. The BACT analysis is presented in Section 5.0, and the air quality impact analysis for the project is contained in Section 6.0. The additional impact analysis required by PSD rules is presented in Sections 7.0 and 8.0. Supporting documentation is presented in the Appendices.

2.0 PROJECT DESCRIPTION

GP is proposing to modify the No. 4 Combination Boiler to increase the actual amount of bark/wood burned in the Boiler. As part of the project, GP is also proposing to permanently shutdown the No. 4 Power Boiler. The facility is currently operating under Title V Permit No. 1070005-029-AV, issued February 7, 2005. The facility is located west of U.S. Hwy 17, on State Road (SR) 216, north of Palatka in Putnam County. A plot plan of the facility, showing stack locations, is presented in Figure 2-1. The following sections describe the proposed project in more detail.

2.1 EXISTING OPERATIONS

GP currently operates the No. 4 Combination Boiler to provide steam to the papermaking process and the turbine generators that provide electricity for the facility. The Boiler is of Babcock & Wilcox (B&W) design, with a design steam rating of 360,000 pounds per hour (lbs/hr). The No. 4 Combination Boiler is permitted to burn the following fuels and gases:

- Carbonaceous fuel, such as tree bark and wood fuel (supplied from the Bark Handling System).
- No. 6 fuel oil, with a sulfur content not to exceed 2.35 percent by weight, and on-spec used oil.
- Natural gas as a startup fuel (the natural gas may be kept on pilot for flame safety).
- Non-condensable gases (NCGs) from the low-volume, high concentration (LVHC) gas collection system, and/or condensate stripper off-gas (SOG), during periods when the Boiler is being utilized for the destruction of these gases (maximum of 20 percent of the time on an annual basis, as a backup to the Thermal Oxidizer). Also, once the newly permitted Brown Stock Washer and Oxygen Delignification Systems are installed (permit issued July 2, 2004), dilute non-condensable gases (DNCGs) from these systems will be burned in the Boiler as the primary destruction device. The burning of the NCGs, SOG, and DNCGs in the No. 4 Combination Boiler were all permitted as part of pollution control projects (PCPs) to control emissions of hazardous air pollutants (HAPs).

The No. 4 Combination Boiler currently is permitted to operate up to a maximum heat input rate of 512.7 million British thermal units per hour (MMBtu/hr) for carbonaceous fuel burning. Based on a minimum heat content of 4,500 British thermal units per pound (Btu/lb), this heat input rate is equivalent to a maximum bark/wood burning rate of 57.0 TPH and 499,320 tons per year (TPY).

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

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

2.2 PROPOSED MODIFICATIONS

GP is proposing modifications to the No. 4 Combination Boiler to allow the Boiler to burn an increased amount of bark/wood. The Boiler is currently permitted to burn up to 1,368 tons per day (TPD) of bark/wood. However, historically the Boiler has not been able to achieve this rate due to the bark/wood feeders, limited combustion air supply, and limited ash removal capabilities. For example, during the last two years, the maximum bark/wood usage rate for any day was only 1,130 TPD.

GP is requesting changes to the No. 4 Combination Boiler in order to increase the actual amount of bark/wood fuel that can be burned in the Boiler. GP is considering a number of changes to the No. 4 Combination Boiler, including:

- Upgrading the bark/wood fuel delivery system by replacing worn out feed system parts, removing the existing bark bin, and modifying conveyors to accommodate these changes.
- Installing a bark/wood feed system, including a live bottom bark/wood bin.
- Installing an underfire air (UFA) system in the Boiler.
- Upgrading an OFA system in the Boiler.
- Installing a new ash handling system to handle the increased ash generation rates.
- Installing new low-NO_x burners for fuel oil firing. The new burners will be of the same capacity and number as the existing burners.
- Improving operation of the electrostatic precipitator (ESP) used to control particulate emissions from the Boiler.

Engineering evaluations are ongoing, and final engineering may dictate that some of these changes will be implemented, while others may not.

GP is considering upgrading the OFA system on the Boiler. Such systems have been installed on a number of bark/wood boilers throughout the country, and have resulted in positive improvements to the boilers, including increased combustion efficiency and a reduction in the amount of excess air used in the boiler, without increasing emissions of particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), nitrogen oxides (NO_x), CO, or volatile organic compound (VCO), on a lb/MMBtu basis. Additional information regarding two such OFA systems is provided in Appendix C. GP has not committed to an OFA system or a specific vendor at this time, but the information in Appendix C represents options that are being considered.

The project will result in an increase in the actual amount of bark/wood fuel burned in the No. 4 Combination Boiler on a short-term basis and an annual average basis. However, the current permitted maximum hourly bark/wood heat input and burning rates will not be increased as part of this project. This hourly rate is 512.7 MMBtu/hr. To limit future potential emissions from the No. 4 Combination Boiler, GP is also requesting an annual limitation on heat input rate to the Boiler of 4,042,127 MMBtu/yr. This is equivalent to 449,125 TPY wet wood at 4,500 Btu/lb. This annual heat input rate represents a 90-percent capacity factor.

The maximum heat input rate when firing No. 6 fuel oil will not be affected by the proposed project, although it is likely that the project will result in a reduction in annual fuel oil usage in the Boiler, since the preferred fuel is bark/wood. As part of this project, GP will limit future annual No. 6 fuel oil consumption in the No. 4 Combination Boiler to 5,300,000 gallons per year (795,000 MMBtu/yr) to limit the future potential annual SO_2 emissions from the Boiler. GP will also install new low-NO_x burners for fuel oil firing. These burners will be the same capacity and number as the current burners.

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

2.3 AIR EMISSION ESTIMATES AND POLLUTION CONTROL EQUIPMENT

PM/PM_{10} emissions from the No. 4 Combination Boiler are currently controlled by a centrifugal collector followed by an ESP. GP is proposing to upgrade the Boiler fuel feed system and OFA system. This upgrade is expected to increase the bark/wood burning rate and reduce the amount of No. 6 fuel oil consumption, while not increasing emissions of PM/PM_{10}, CO, NO_x, or VOCs on a lb/MMBtu basis for bark/wood burning or No. 6 fuel oil burning.

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

GP is also considering measures to maximize ESP performance. The ESP serving the No. 4 Combination Boiler has three (3) fields. There is no physical room to add another field. However, the first two fields have experienced some plate warping and these could be repaired to maximize ESP power output. GP will also implement better controls on the ESP to optimize the rapping rates. These changes should further result in a reduction in PM/PM_{10} emissions on a lb/MMBtu basis, and achieve more consistent ESP operation.

2.3.1 PAST ACTUAL EMISSIONS

The past actual average emissions for 2003-2004 from the No. 4 Combination Boiler are presented in Table 2-1. The past actual emissions for the No. 4 Combination Boiler were obtained from the Annual Operating Reports (AORs) submitted to the Florida Department of Environmental Protection (FDEP) for these sources, except for the following differences:

- SO_2 emissions for fuel oil firing for calendar year 2003 were corrected to reflect the equation in the Title V operating permit for the Boiler (see footnote "j" in Table 2-1).
- Past actual NO_x emissions from the No. 4 Combination Boiler for bark/wood firing were reported in the AORs based on AP-42 emission factors (0.22 lb/MMBtu). However, this factor is a general factor and may not be representative of an individual boiler. Very limited test data on the No. 4 Combination Boiler indicates NO_x emissions in the range of 0.15 to 0.21 lb/MMBtu. These tests were conducted for the purpose of assessing the affects of SOG burning in the No. 4 Combination Boiler. Although limited information is available concerning current NO_x emissions from the Boiler, calculations demonstrate that use of a higher NO_x factor for both the current actual and future potential emissions (since no increase in emissions on a lb/MMBtu basis is expected) results in a greater net increase in NO_x emissions due to the project. As a result, the NO_x emission factor used for bark/wood firing for purposes of calculating the past actual emissions in this application was 0.24 lb/MMBtu. This emission factor incorporates a safety factor above the limited test data.
- Past actual PM emissions were calculated based on actual fuel oil usage, wood/bark burned, and stack test data (refer also to Table 3-5 in Section 3.0). PM_{10} emissions were

estimated at 63 percent of PM for fuel oil and 74 percent of PM for wood/bark for a boiler with an ESP control device. This is based on AP-42, Section 1.3, Table 1.3-4.

- VOC emissions due to wood/bark burning were based on an updated emission factor of 0.017 lb/MMBtu from AP-42, Section 1.3.
- Sulfuric acid mist (SAM) emissions were not reported in the AORs for the Boiler. Therefore, SAM was calculated based on a derivation from the U.S. Environmental Protection Agency (EPA) Publication AP-42, by multiplying the SO_2 emissions by 4.4 percent [3.6 percent of SO_2 becomes sulfur trioxide (SO_3), then taking into account the ratio of SAM and SO_3 molecular weights (98/80)].
- Mercury (Hg) and fluorides (F) emissions were not reported in the AOR. Hg and F emissions were calculated based on the actual amount of fuel oil or wood/bark burned in the No. 4 Combination Boiler. Emission factors were obtained from AP-42.

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

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

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

- PM_{10} emissions for the year 2001 were recalculated based on AP-42, Section 1.3, Table 1.3-5, which provides an equation for industrial boilers with no control device firing No. 6 fuel oil (see footnote "l" in Table 2-1).
- SAM emissions were not reported in the AORs for the Boiler. Therefore, SAM was calculated based on a derivation from EPA Publication AP-42, by multiplying the SO_2 emissions by 4.4 percent [3.6 percent of SO_2 becomes sulfur trioxide (SO_3), then taking into account the ratio of SAM and SO_3 molecular weights (98/80)].
- Hg and F emissions were not reported in the AOR. Hg and F emissions were calculated based on the actual amount of fuel oil burned in the No. 4 Power Boiler. Emission factors were obtained from AP-42.

2.3.2 FUTURE POTENTIAL EMISSIONS

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

Future annual heat input to the No. 4 Combination Boiler will be limited to 4,042,127 MMBtu/yr to limit the potential emissions from the Boiler. This limit is equivalent to a 90-percent capacity factor on wood/bark. Future No. 6 fuel oil burning will be limited to 5,300,000 gal/yr (795,000 MMBtu/yr). The new low-NO_x No. 6 fuel oil burners will be designed to limit NO_x emissions to 0.2 lb/MMBtu.

As described previously, no increase in NO_x emissions due to bark/wood firing is expected on a lb/MMBtu basis due to the proposed project. The past actual NO_x emissions were based on a factor of 0.24 lb/MMBtu. Therefore, the factor to estimate future potential NO_x emissions due to bark/wood firing was also set at 0.24 lb/MMBtu.

PM emissions from the No. 4 Combination Boiler will be limited to 0.07 lb/MMBtu, which is equivalent to the National Emission Standards for Hazardous Air Pollutants (NESHAPs) promulgated for Industrial Boilers [Code of Federal Regulations, Title 40, Part 63 (40 CFR 63), Subpart DDDDD (see Sections 3.3.2 and 3.4.3.2)]. This is a significant reduction from the current PM limit of 0.3 lb/MMBtu for wood/bark burning and 0.1 lb/MMBtu for fuel oil burning. The proposed emission limit is equivalent to 29.3 lbs/hr and 27.8 TPY for No. 6 fuel oil, and 35.9 lbs/hr and 141.5 TPY for wood/bark-firing (refer to Appendix A for calculations).

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

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

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

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

2.4 EFFECTS ON OTHER EMISSION UNITS

Only one other emission unit at the GP Palatka Mill may potentially be affected (*i.e.*, increased process rates or increased actual air emission rates) due to the proposed modification of the No. 4 Combination Boiler. Wood chips and bark are supplied to the No. 4 Combination Boiler by the Bark Handling System. Since the actual amount of bark/wood consumed in the Boiler will be increasing as part of this project, the Bark Handling System is affected by this proposed project. However, GP recently submitted a separate PSD application to apply for changes to the Bark Handling System, including the installation of a new bark hog. The recent PSD application was based on the maximum bark/wood processing rate through the Bark Handling System, which is also the maximum rate needed to support the maximum permitted bark/wood firing rate of the No. 4 Combination Boiler. Since the maximum permitted bark/wood firing rate for the No. 4 Combination Boiler is not increasing due to the proposed project, and since the Bark Handling

System has recently undergone PSD review in a separate action with this maximum rate, the Bark Handling System is not considered in the proposed No. 4 Combination Boiler project.

Table 2-1. Summary of Past Actual Emissions From No. 4 Combination Boiler and No. 4 Power Boiler, Georgia-Pacific, Palatka Mill

Source Description	EU ID	Pollutant Emission Rate (TPY)										
		SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM[a]	Lead	Mercury	Fluorides
No. 4 Power Boiler												
2001 Actual Emissions	014	296 2	36 2	3.9	19.8	17.19 [l]	0.22	–	13.0	0.009	0.000087 [g]	0 029 [g]
2002 Actual Emissions		245.0	31.1	3.3	16 5	14.29	0 19	–	10.8	0 001	0.000075 [g]	0.025 [g]
Average Actual Emissions		**270.6**	**33.6**	**3.6**	**18.1**	15.7	**0.20**	–	**11.9**	**0.005**	**0.000081**	0.027
No. 4 Combination Boiler	016	–	–	–	–	–	–	–	–	–	–	–
2003 Actual Emissions												
–Fuel Oil Usage		753.3 [j]	101.8	10 8	10.7 [c]	6 8 [e]	0 6	–	33.1	0 003	0 00024 [h]	0.081 [h]
–Wood/Bark Usage		33.0	316.7 [b]	791.8	118.8 [d]	87.9 [f]	22.4 [k]	–	1 5	0 047	0.0046 [i]	–
–NCG/SOG Burning		317.7	22.7	–	–	–	–	0.5	14 0	–	–	–
–Total (Without NCGs/SOG)		**786.3**	**418.6**	**802.7**	**129.5**	**94.7**	**23.0**	**0.0**	34.6	**0.05**	**0.0049**	**0.081**
2004 Actual Emissions												
–Fuel Oil Usage		763.6	102.3	10.9	9 8 [c]	6.2 [e]	0.6	–	33 6	0.003	0.00025 [h]	0 081 [h]
–Wood/Bark Usage		33 8	324.2 [b]	810.6	81.1 [d]	60.0 [f]	23 0 [k]	–	1.5	0 065	0.0048 [i]	–
–NCG/SOG Burning		281.9	19.1	–	–	–	–	0 5	12.4	–	–	–
–Total (Without NCGs/SOG)		**797.4**	**426.5**	**821.5**	**90.9**	**66.2**	**23.6**	**0.0**	**35.1**	**0.07**	**0.0050**	**0.081**
Average Actual Emissions												
–Total (Without NCGs/SOG)		791.9	**422.6**	**812.1**	110.2	**80.4**	**23.3**	0.0	**34.8**	**0.059**	**0.0050**	**0.081**

TPY = tons per year.

Source: Annual Operating Reports submitted to Florida DEP.

Footnotes:

[a] Not reported on AOR. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3 6% of SO_2 becomes SO_3, then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).

[b] NO_x from wood/bark based on 0.24 lb/MMBtu (converted to lb/ton wood/bark by multiplying by 9 MMBtu/ton) and actual wood/bark burning rate (300,219 TPY for 2004 and 293,274 TPY for 2003).

[c] PM based on the actual fuel oil usage (4,351,660 gal/yr in 2004 and 4,333,320 gal/yr in 2003), heat content of fuel oil (150,000 Btu/gal), and actual stack test data (0.033 lb/MMBtu on 1/8/03 and 0.03 lb/MMBtu on 1/8/04).

[d] PM based on the actual wood/bark burned (300,219 TPY in 2004 and 293,274 TPY in 2003), heat content of wood/bark (4,500 Btu/lb), and actual stack test data (0.06 lb/MMBtu on 1/8/03 and 0 09 lb/MMBtu on 1/8/04).

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

[f] PM_{10} = 74% of PM, which is based on the ratio of individual emission factors for PM and PM_{10} from AP-42 Table 1.6-1 for wood-residue fired boilers with an ESP (0 054 lb/MMBtu for PM; 0.04 lb/MMBtu for PM_{10}).

[g] Mercury and F emissions based on actual fuel oil usage (1,323,000 gal/yr for 2002 and 1,540,000 gal/yr for 2001) and emission factors from AP-42 Section 1 3-11 (Hg = 1.13E-04 lb/1000 gal; F = 3.73E-02 lb/1000 gal).

[h] Mercury and F emissions based on actual fuel oil usage (4,351,660 gal/yr in 2004 and 4,333,320 gal/yr in 2003) and emission factors from AP-42 Section 1.3-11 (Hg = 1.13E-04 lb/1000 gal; F = 3.73E-02 lb/1000 gal)

[i] Mercury based on actual wood/bark burned (300,219 TPY in 2004 and 293,274 TPY in 2003) and emission factor from AP-42 Section 1 6-4 (Hg = 3.5E-06 lb MMBtu converted to 3.15E-05 lb/ton bark by multiplying by 9 MMBtu/ton).

[j] SO_2 emissions recalculated based on equation in Title V permit: 0 164 x %S x gallons fuel fired / 2000 lbs/ton = tons SO_2.

[k] VOC revised based on updated AP-42 factor for wood firing of 0 017 lb/MMBtu.

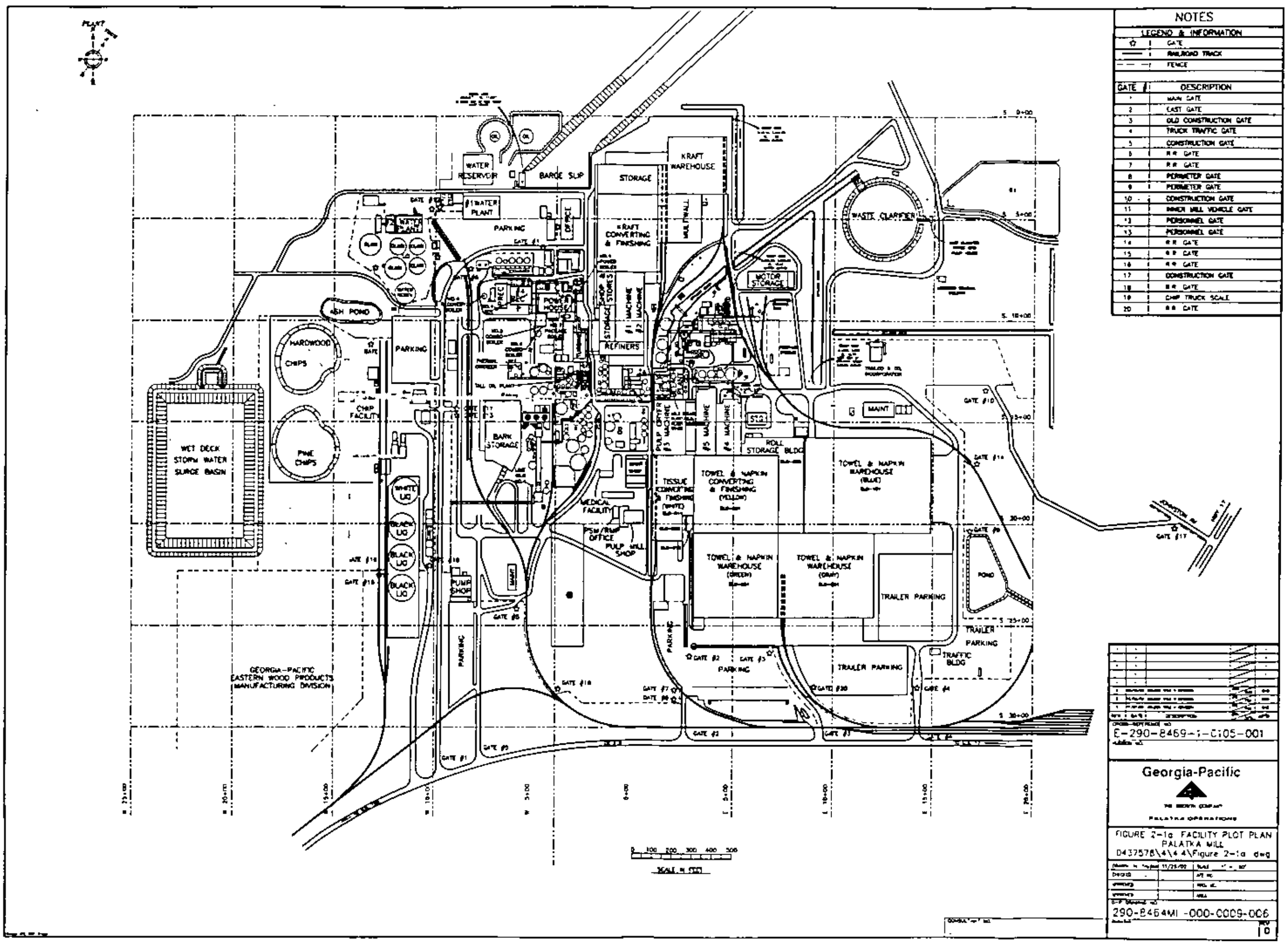
[l] Based on AP-42 Section 1.3, Table 1.3-5, for industrial boilers firing residual oil with no PM control device: 7.17*[1.12(%S)+0.37] lb/1000 gal.

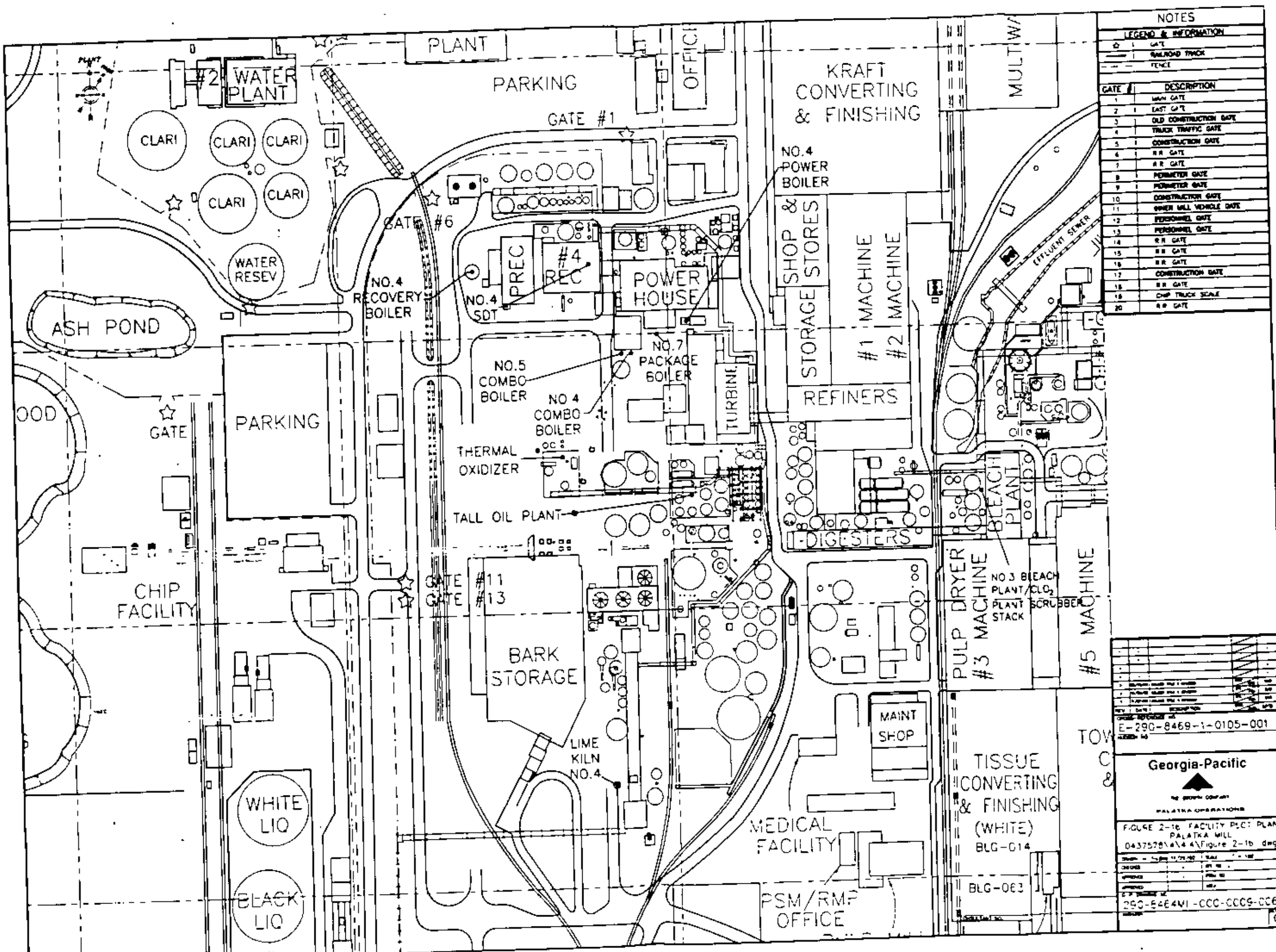
Table 2-2. Future Potential Annual Emissions for Different Fuel Burning Scenarios, No. 4 Combination Boiler, GP Palatka Mill

Source Description	Pollutant Emission Rate (TPY)										
	SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Hg	F
No. 4 Combination Boiler											
--Max Fuel Oil & Wood/Bark Usage	1,061.9	485.1	1,212.6	141.5	104.7	34.4	--	46.7	0.072	0.007	0.099
--NCGs/SOG/DNCGs Burning	785.0	37.8	--	--	--	--	15.7	34.5	--	--	--
--Maximum for Any Fuel (With NCGs/SOG/DNCGs)	**1,846.9**	**522.9**	**1,212.6**	**141.5**	**104.7**	**34.4**	**15.7**	**81.3**	**0.072**	**0.007**	**0.099**
--Maximum for Any Fuel (Without NCGs/SOG/DNCGs)	**1,061.9**	**485.1**	**1,212.6**	**141.5**	**104.7**	**34.4**	**--**	**46.7**	**0.072**	**0.007**	**0.099**

TPY = tons per year.

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


NOTES
LEGEND & INFORMATION
GATE
RAILROAD TRACK
FENCE
GATE # | DESCRIPTION
1 MAIN GATE
2 EAST GATE
3 OLD CONSTRUCTION GATE
4 TRUCK TRAFFIC GATE
5 CONSTRUCTION GATE
6 R R GATE
7 R R GATE
8 PERIMETER GATE
9 PERIMETER GATE
10 CONSTRUCTION GATE
11 INNER MILL VEHICLE GATE
12 PERSONNEL GATE
13 PERSONNEL GATE
14 R R GATE
15 R R GATE
16 R R GATE
17 CONSTRUCTION GATE
18 R R GATE
19 CHIP TRUCK SCALE
20 R R GATE
WATER RESERVOIR
BARGE SLIP
STORAGE
KRAFT WAREHOUSE
KRAFT CONVERTING & FINISHING
MULTIWALL
OFFICE
PARKING
WASTE CLARIFIER
MOTOR STORAGE
ASH POND
HARDWOOD CHIPS
PINE CHIPS
WET DECK STORM WATER SURGE BASIN
CHIP FACILITY
BARK STORAGE
REFINERS
TALL OIL PLANT
MAINT
ROLL STORAGE BLDG
TISSUE CONVERTING FINISHING (WHITE)
TOWEL & NAPKIN CONVERTING & FINISHING (YELLOW)
TOWEL & NAPKIN WAREHOUSE (BLUE)
TOWEL & NAPKIN WAREHOUSE (GREEN)
TOWEL & NAPKIN WAREHOUSE (GRAY)
MEDICAL FACILITY
PSM/RMP OFFICE
PULP MILL SHOP
PUMP SHOP
WHITE LIQ
BLACK LIQ
BLACK LIQ
BLACK LIQ
TRAILER PARKING
TRAILER PARKING
TRAFFIC BLDG
POND
GEORGIA-PACIFIC EASTERN WOOD PRODUCTS MANUFACTURING DIVISION
SCALE IN FEET
0 100 200 300 400 500
E-290-8469-1-C105-001
Georgia-Pacific
FIGURE 2-1a FACILITY PLOT PLAN
PALATKA MILL
D437578\4\4 4\Figure 2-1a dwg
290-8464MI -000-0009-006
0



NOTES
PLANT
PARKING
#2 WATER PLANT
CLARI
CLARI
CLARI
CLARI
CLARI
WATER RESEV
ASH POND
GATE #1
GATE #6
OFFICE
KRAFT CONVERTING & FINISHING
MULTIWALL
NO.4 POWER BOILER
NO.4 RECOVERY BOILER
NO.4 SDT
PREC
#4 REC
POWER HOUSE
SHOP & STORES
STORAGE
#1 MACHINE
#2 MACHINE
NO.7 PACKAGE BOILER
NO.5 COMBO BOILER
NO.4 COMBO BOILER
TURBINE
REFINERS
PARKING
GATE
THERMAL OXIDIZER
TALL OIL PLANT
DIGESTERS
BLEACH PLANT
EFFLUENT SEWER
CHIP FACILITY
GATE #11
GATE #13
BARK STORAGE
PULP DRYER
#3 MACHINE
NO.3 BLEACH PLANT/CLO_2 PLANT SCRUBBER STACK
#5 MACHINE
LIME KILN NO.4
MAINT SHOP
TISSUE CONVERTING & FINISHING (WHITE)
BLG-014
BLG-063
WHITE LIQ
BLACK LIQ
MEDICAL FACILITY
PSM/RMP OFFICE
E-290-8469-1-0105-001
Georgia-Pacific
FIGURE 2-1b FACILITY PLOT PLAN
PALATKA MILL
0437578\4\4.4\Figure 2-1b dwg
290-64E4MI-CCC-CCC9-CC6

3.0 AIR QUALITY REVIEW REQUIREMENTS

Federal and State air regulatory requirements for a major new or modified source of air pollution are discussed in Sections 3.1 through 3.3. The applicability of these regulations to the proposed GP modification is presented in Section 3.4. These regulations must be satisfied before the proposed project can be approved.

3.1 NATIONAL AND STATE AMBIENT AIR QUALITY STANDARDS

The existing applicable national and Florida Ambient Air Quality Standards (AAQS) are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas and new or modified sources to be located in or near these areas may be subject to more stringent air permitting requirements.

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

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

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

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

The EPA class designation and allowable PSD increments are also presented in Table 3-1. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications are designated based on criteria established in the 1977 CAA Amendments. Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and nitrogen dioxide (NO_2).

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

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

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

3.2.2 CONTROL TECHNOLOGY REVIEW

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

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

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

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's Guidelines for Determining BACT (EPA, 1978) and in the PSD Workshop Manual (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

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

3.2.3 SOURCE IMPACT ANALYSIS

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

To address compliance with AAQS and PSD Class I and II increments, a source impact analysis must be performed. However, this analysis is not required for a specific pollutant if the net increase in impacts as a result of the new source or modification is below significant impact levels, as presented in Table 3-1. The significant impact levels are threshold levels that are used to determine the level of air impact analyses needed for the project. If the new or modified source's impacts are predicted to be less than significant, then the source's impacts are assumed not to have a significant adverse effect on air quality. Additional modeling, taking into account other emission sources, is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling, including other emission sources, is required in order to demonstrate compliance with AAQS and PSD increments.

EPA has issued guidance related to significant impact levels for Class I areas, as shown in Table 3-1. Although these levels have not been officially promulgated as part of the PSD review process and may not be binding for states in performing PSD reviews, the levels serve as a guideline in assessing a source's impact in a Class I area. The EPA action to incorporate Class I significant impact levels into the PSD process is part of implementing the NSR regulations. Because the process of developing the regulations will be lengthy, EPA believes that the guidance concerning the significant impact levels is appropriate to assist states in implementing the PSD permit process.

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

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

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

- The actual emissions representative of facilities in existence on the applicable baseline date; and
- The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM_{10}, or February 8, 1988, for NO_2, but that were not in operation by the applicable baseline date.

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

- Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM_{10}, and after February 8, 1988, for NO_2; and
- Actual emission increases and decreases at any stationary facility occurring after the baseline date.

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

- The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM_{10}, and February 8, 1988, in the case of NO_2;
- The trigger date, which is August 7, 1977, for SO_2 and PM_{10}, and February 8, 1988, for NO_2; and
- The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application.

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

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

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

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

3.2.5 SOURCE INFORMATION/GEP STACK HEIGHT

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

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

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

$$Hg = H + 1.5L$$

where: Hg = GEP stack height,
H = Height of the structure or nearby structure, and
L = Lesser dimension (height or projected width) of nearby structure(s); or

- A height demonstrated by a fluid model or field study.

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

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

3.2.6 ADDITIONAL IMPACT ANALYSIS

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

3.3 POTENTIALLY APPLICABLE EMISSION STANDARDS

3.3.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the CAA Amendments of 1970, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

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

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

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

40 CFR 60.5 defines "***fixed capital cost***" as the capital needed to provide all the depreciable components. 40 CFR 60.2 defines "***capital expenditure***" as:

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

Federal NSPS exist for fossil-fuel and wood-fired industrial-commercial-institutional steam boilers constructed or modified after June 19, 1984. The NSPS are contained in 40 CFR 60, Subpart Db. The NSPS contain emission limits for SO_2, PM, and NO_x for oil firing and emission limits for PM for wood firing. Wood is defined in the NSPS to include bark, wood, and wood residue. Subpart Db is potentially applicable for the No. 4 Combination Boiler project.

Federal NSPS also exist for Fossil-Fuel-Fired Steam Generators for which construction or modification occurs after August 17, 1971 (40 CFR 60, Subpart D). The NSPS contains emission limits for PM, SO_2, and NO_x for liquid fossil fuel and wood residue firing. However, 40 CFR 60, Subpart Db, contains a provision than any unit subject to Subpart Db is not subject to Subpart D.

3.3.2 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

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

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

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

3.3.3 FLORIDA RULES

Emission limitations applicable to carbonaceous fuel burning equipment are contained in Rule 62-296.410 F.A.C. This rule limits PM emissions, as well as visible emissions, from such equipment. In addition, Rule 62-296.404 regulates the burning of total reduced sulfur (TRS)-containing gases (*i.e.*, NCGs, SOG, etc.) in boilers.

3.4 SOURCE APPLICABILITY

3.4.1 AREA CLASSIFICATION

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

3.4.2 PSD REVIEW

3.4.2.1 Pollutant Applicability

The GP Palatka Mill is considered to be an existing major stationary facility because potential emissions of at least one PSD-regulated pollutant exceed 100 TPY (for example, potential SO_2 emissions currently exceed 100 TPY). Therefore, PSD review is required for any pollutant for which the net increase in emissions due to the modification is greater than the PSD significant emission rates (see Table 3-2).

The net increase in emissions due to the proposed modification at the GP Palatka Mill is summarized in Table 3-3. For the No. 4 Combination Boiler, the future potential and past actual emissions are based on information from Section 2.0. The past actual emissions from the No. 4 Power Boiler are also included in the table, since this source is shutting down as part of this project. As described in Section 2.4.1, the future potential and past actual emissions from the No. 4 Combination Boiler due to NCGs/SOG/DNCGs destruction have been excluded from this analysis.

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

3.4.2.2 Source Impact Analysis

A source impact analysis was performed for CO emissions resulting from the proposed modification. This analysis is presented in Section 6.0.

3.4.2.3 Ambient Monitoring

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

Pre-construction monitoring data for CO can be exempted for this project because, as shown in Table 3-4 and Section 6.0, the proposed modification's impacts are predicted to be less than the applicable *de minimis* monitoring concentrations for these pollutants.

3.4.2.4 GEP Stack Height Impact Analysis

All existing stacks at the GP facility currently comply with GEP stack height regulations. In addition, no new stacks are proposed as part of this project. Therefore, the proposed modification will comply with the GEP stack height regulations.

3.4.3 EMISSION STANDARDS

3.4.3.1 New Source Performance Standards

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

The Boiler will not be undergoing any physical change to the existing fuel oil firing system, or any increase in the maximum fuel oil firing rate or maximum emissions due to fuel oil firing, as part of the proposed project. As a result, the NSPS will not be triggered by the proposed project in regards to fuel oil firing and associated emission limits.

The Boiler will be undergoing a physical change for the bark/wood burning system, potentially firing more bark/wood on an hourly basis, and potentially increasing actual PM emissions on an hourly basis. Therefore, the proposed project could constitute a "modification", which would subject the No. 4 Combination Boiler to regulation under 40 CFR 60, Subpart Db. The NSPS limit for PM emissions due to bark/wood firing is 0.1 lb/MMBtu. However, GP is proposing to reduce the current PM emission limit on the Boiler to 0.07 lb/MMBtu. At this maximum emission rate, the maximum hourly PM emissions from the Boiler are 35.9 lbs/hr (refer to Appendix A, Tables A-3 and A-4).

A summary of historical PM compliance test data for the No. 4 Combination Boiler is shown in Table 3-5. These historic compliance tests were conducted while burning a combination of bark/wood and fuel oil, in order to achieve at least 90 percent of rated heat input capacity during the testing. GP has also conducted two compliance tests while burning fuel oil only. As shown in Table 3-5, these tests showed similar results (PM emissions of about 0.03 lb/MMBtu).

Using the results of the fuel oil tests, the PM emissions due to bark/wood firing only can be estimated. These are also shown in Table 3-5, and indicate PM emissions due to bark/wood firing ranging from 0.030 to 0.135 lb/MMBtu. Statistical analysis indicates that PM emissions due to bark/wood firing only could be as high as 0.20 lb/MMBtu, based on a 99-percent confidence interval.

Based on the historical PM test data, PM emissions from the No. 4 Combination Boiler have been as high as 43.8 lbs/hr. The most recent test resulted in PM emissions of 39.1 lbs/hr. The proposed maximum PM emission rate after the proposed project is implemented is 35.9 lbs/hr. Therefore, the proposed project will not result in an increase in hourly PM emissions, and Subpart Db will not apply in regard to wood/bark firing.

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

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

3.4.3.2 NESHAPs for Source Categories

EPA recently promulgated the Industrial Boiler MACT (40 CFR 63, Subpart DDDDD), and the No. 4 Combination Boiler is subject to this rule. The Industrial Boiler MACT regulates PM (as a surrogate for metallic HAPs), HCl, and Hg emissions from existing large solid fuel-fired industrial boilers. The No. 4 Combination Boiler is in the large solid fuel-fired subcategory, and the applicable emission limits for bark/wood firing are 0.07 lb/MMBtu for PM (or 0.001 lb/MMBtu for total selected metals), 0.09 lb/MMBtu for HCl, and 9×10^{-6} lb/MMBtu for Hg. The compliance date for existing boilers is September 13, 2007. GP will comply with the applicable standards by the compliance date. Based on current information, GP believes the Boiler will be able to comply with the PM (or total selected metals), HCl, and Hg limits by means of fuel analysis or stack testing.

As discussed in Section 3.4.3.1 above, the planned modifications to the No. 4 Combination Boiler represent only about 18 percent of the cost of a new boiler. As a result, the No. 4 Combination Boiler will not be "reconstructed" for the purposes of the MACT rule.

3.4.3.3 State of Florida Standards

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

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

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

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

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

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

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

[d]Maximum concentrations.

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

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

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

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

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

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

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

Table 3-3. Contemporaneous and Debottlenecking Emissions Analysis and PSD Applicability, No. 4 Combination Boiler Project

Source Description	Pollutant Emission Rate (TPY)										
	SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluoride
No. 4 Combination Boiler											
Future Potential Emissions[a]	1,061.9	485.1	1,212 6	141.5	104.7	34.4	--	46.7	0.07	0 007	0.099
Past Actual Emissions[b]	791.9	422.6	812.1	110.2	80.4	23.3	0 0	34 8	0.06	0.0050	0.081
Increase Due to Project	**270.0**	**62.5**	**400.6**	**31.3**	**24.3**	**11.0**	**0.0**	**11.9**	**0.01**	**0.0021**	**0.018**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0.6	0.1	3.0
Netting Triggered?	Yes	Yes	Yes	Yes	Yes	No	No	Yes	No	No	No
CONTEMPORANEOUS EMISSION CHANGES[c]											
Chlorine Dioxide Plant (11/00) (Permit no. 1070005-005-AC)											
--Increase Due to Modified ClO_2 Plant	--	--	--	--	--	[e]	--	--	--	--	--
--Decrease Due to Existing ClO_2 Plant	--	--	--	--	--	[e]	--	--	--	--	--
--Net Change	--	--	--	--	--	[e]	--	--	--	--	--
MACT I Compliance Project (9/00) (Permit nos. 1070005-007-AC and -017-AC)											
--Increase Due to New Thermal Oxidizer	109 7	151 4	8.8	30 7	30.7	[e]	[e]	7.7	--	--	--
--Increase Due to Modified No. 4 Comb Boiler	548.7	37 8	--	--	--	[e]	[e]	21.9	--	--	--
--Increase Due to BSW System w/Condensate Treatment	--	--	--	--	--	[e]	[e]	--	--	--	--
--Decrease Due to Existing Thermal Oxidizer	-749.8	-49.5	-0.3	-20.6	-20.6	[e]	[e]	-26.9	--	--	--
--Decrease Due to Existing BSW System w/o Condensate Treatment	--	--	--	--	--	[e]	[e]	--	--	--	--
--Net Change	-91 4	139 7 [c,d]	8.5	10.1	10.1	[e]	[e]	2 7	--	--	--
New Package Boiler (9/02) (Permit No. 1070005-018-AC)											
--Increase Due to New Package Boiler (EU 044)	0.1	39 4	16.5	1.5	1.5	[e]	[e]	--	[e]	[e]	[e]
--Decrease from old No. 6 Package Boiler	-0.07	-9.2	-2.1	-0 15	-0.15	[e]	[e]	--	[e]	[e]	[e]
--Net Change	0 03	30 20	14 40	1.35	1.35	[e]	[e]	--	[e]	[e]	[e]
Brown Stock Washer and Oxygen Delignification System (6/04) (Permit No. 1070005-024-AC)	[e]	--	0.3	--	--	[e]	[e]	[e]	[e]	[e]	[e]
Bark Hog Replacement Project (11/04) (Draft permit no. 1070005-028-AC/PSD-FL-341)	--	--	--	8 22 [f]	3.26 [f]	[d]	--	--	--	--	--
Lime Kiln Shell Replacement (9/04)	29.5	[d]	65.8	[d]	[d]	[d]	[d]	1 5	0.007	--	--
No. 4 Power Boiler Shutdown	-270 6	-33.6	-3 6	-18.1	-15 7	[e]	[e]	-7.1	[e]	[e]	[e]
Total Contemporaneous Emission Changes	-241.1	-33.6	85.4	-18.1	-15.7	N/A	N/A	-5.6	N/A	N/A	N/A
TOTAL NET CHANGE	28.9	28.9	485.9	13.2	8.5	N/A	N/A	6.3	N/A	N/A	N/A
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0 6	0.1	3.0
PSD REVIEW TRIGGERED?	No	No	Yes	No	No	No	No	No	No	No	No

Footnotes:

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

[b] Based on actual emissions for 2002 and 2003 from Table 2-1 (without NCGs, SOG, DNCGs).

[c] Pollution Control Projects (PCP) approved for G-P Palatka Mill are excluded since these projects are exempted from PSD review.

[d] Denotes that PSD review was triggered for this pollutant; therefore this, and any previous contemporaneous increases/decreases, are wiped clean.

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

[f] As estimated by FDEP (see draft Technical Evaluation and Preliminary Determination for Bark Hog Replacement PSD, November 2004).

Table 3-4. Predicted Impacts Due to the Proposed Project Compared to Ambient Monitoring *De Minimis* Levels

Pollutant	Averaging Time	Maximum Concentration[a] (μg/m³)	*De Minimis* Monitoring Concentration (μg/m³)	Ambient Monitoring Review Applies?
Carbon Monoxide	8-hour	4.0	575	No

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

Note: NA = Not Applicable

Table 3-5. Summary of Historical PM Stack Test Data for the No. 4 Combination Boiler, Georgia-Pacific Palatka

Test Date	Heat Input Rate (MMBtu/hr)	Total PM Emissions		Individual Heat Input Rates (MMBtu/hr)		PM Emissions (lb/hr) -- Contributions by Individual Fuels		PM Emissions (lb/MMBtu)
		lb/hr	lb/MMBtu	Due to Oil	Due to Bark/Wood	Due to Oil/Wood Only [a]	Due to Bark/Wood Only [b]	Due to Bark/Wood Only
Wood/Bark and Fuel Oil in Combination								
1/8/2004	496	39.10	0.090	107	389	3.31	35.79	0.092
1/8/2003	457	26.42	0.060	107	350	3.32	23.10	0.066
6/18/02-6/21/02	455	19.73	0.047	155	300	4.80	14.93	0.050
7/18/2001	442	15.77	0.040	151	291	4.69	11.08	0.038
4/18/2000	438	43.77	0.101	103	335	3.19	40.58	0.121
5/19/1999	473	14.20	0.030	126	347	3.92	10.28	0.030
5/6/1998	458	16.00	0.040	144	314	4.47	11.53	0.037
2/20/1997	453	40.00	0.090	119	334	3.68	36.32	0.109
4/2/1996	502	26.00	0.052	321	181	9.96	16.04	0.089
7/24/95-7/25/95	470	38.34	0.080	242	228	7.50	30.84	0.135
							No. of tests =	**10**
							Average =	**0.077**
							Standard Deviation =	**0.038**
							95% Confidence Interval Upper Limit =	**0.162**
							99% Confidence Interval Upper Limt =	**0.200**
Fuel Oil Only								
1/8/2004	403	12.60	0.030					
1/8/2003	420	13.87	0.033					
		No. of Tests =	**2**					
		Average =	**0.032**					
		Standard Deviation =	**0.002**					
		95% Confidence Interval Upper Limit =	**0.058**					
		99% Confidence Interval Upper Limit =	**0.167**					

[a] Assumed at 0.031 lb/MMBtu from stack testing on fuel oil only.

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

4.0 AMBIENT MONITORING ANALYSIS

4.1 MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2). As discussed in Section 3.4.2.1, PM_{10} and CO are subject to PSD pre-construction monitoring requirements for the proposed modification because the net increase in emissions due to the project exceeds the PSD significant emission rate for these pollutants.

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

An exemption from the pre-construction ambient monitoring requirements is also available if certain criteria are met. If the predicted increase in ambient concentrations, due to the proposed modification, is less than specified *de minimis* concentrations, then the modification can be exempted from the pre-construction air monitoring requirements for that pollutant.

The PSD *de minimis* monitoring concentration for CO is 575 $\mu g/m^3$ as an 8-hour average. The predicted increase in CO concentrations due to the proposed modification only is presented in Table 3-4 and in Section 6.0. Since the predicted increase in CO impacts due to the proposed modification is less than the *de minimis* monitoring concentration level, a pre-construction air monitoring analysis is not required for CO.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 REQUIREMENTS

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

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

In the case of the proposed project, only the No. 4 Combination Boiler is being physically modified. As a result, BACT only applies to the No. 4 Combination Boiler. CO emissions from the No. 4 Combination Boiler require a BACT analysis. The BACT analysis is presented in the following sections.

5.2 CARBON MONOXIDE (CO)

5.2.1 PROPOSED CONTROL TECHNOLOGY

CO emissions are proposed to be controlled through proper furnace design and good combustion practices, including control of combustion air and temperature and distribution of fuel on the grate, as well as control over furnace loads and transient conditions. The No. 4 Combination Boiler does not currently have a CO emission limit, but maximum emissions are expected to be 0.60 lb/MMBtu when firing bark/wood, equivalent to 307.62 lbs/hr (24-hour average) and 1,212.6 TPY, and 5 lbs/1,000 gallons for fuel oil firing, equivalent to 13.96 lbs/hr (24-hour average) and 12.5 TPY.

5.2.2 BACT ANALYSIS

5.2.2.1 Previous BACT Determinations

As part of the BACT analysis, a review was performed of previous CO BACT determinations for industrial boilers listed in the RBLC on EPA's web page. A summary of the BACT determinations for biomass-fired industrial boilers from this review is presented in Table 5-1. The CO emission limits for biomass-fired industrial boilers identified in the RBLC search range from 0.03 to 2.25 lb/MMBtu. This rather large range of emissions is due to differences in boiler design and operation, as well as differences in fuel. From the review of previous determinations, it is evident that CO BACT determinations for biomass-fired industrial boilers have all been based on good combustion practices and boiler design.

5.2.2.2 Control Technology Feasibility

The technically feasible CO controls for the No. 4 Combination Boiler are shown in Table 5-2. As shown, there are three types of CO abatement methods. Each available technique was listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency.

5.2.2.3 Potential Control Method Descriptions

Good Combustion Practices

The boiler design generally provides a moderately high temperature with sufficient turbulence and residence time at that temperature to complete combustion of the fuel. Good combustion practices maintain efficient combustion and minimize products of incomplete combustion. To assure good combustion, process monitors can be used to monitor the oxygen (O_2) content of the boiler flue gas. Real-time data is fed to the boiler control room. The boiler operator uses the real time data to adjust the boiler operation to ensure sufficient excess air levels.

Good combustion practices are proposed for the No. 4 Combination Boiler.

Incinerators

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

Combustion Modification-Overfire Air

The main combustion modification technique for reducing CO emissions is the use of an overfire air (OFA) system. The reduction in CO emissions realized from this technique is highly dependent upon the uncontrolled CO concentration, combustion chamber oxygen content, air distribution (*e.g.*, portion of the air introduced through the burners versus through the OFA ports), and type and method of fuel being fired. The use of an OFA system ensures that complete combustion takes place, usually in the upper portion of a boiler's combustion chamber, to reduce the level of CO in the boiler exhaust gases.

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

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

5.2.2.4 <u>Environmental Impacts</u>

As shown in Table 6-7, the maximum predicted CO impacts for the proposed project are below the EPA Class I and II significant impact levels, respectively. Additional CO controls would result in an insignificant reduction of ambient impacts that are already below the EPA significance levels for both Class I and II areas.

5.2.2.5 Energy Impacts

Although thermal incinerators are theoretically feasible for the Boiler, because of the high flue gas volume and low concentration of CO, it is estimated that the total incinerator natural gas usage would be approximately 14,000 standard cubic feet per hour (scf/hr), equal to 120 MMscf/yr. The combustion of natural gas would result in increased NO_x emissions, as well as have a significant economic impact (approximately $840,000 per year). For this reason, incineration is considered not feasible for the Boiler.

5.2.3 BACT SELECTION

The only feasible control technologies for CO control in the No. 4 Combination Boiler are good combustion practices and design of the OFA/UFA systems. The No. 4 Combination Boiler will employ both of these control techniques.

CO emissions are proposed to be controlled through proper furnace design and good combustion practices, including control of combustion air and temperature and distribution of fuel on the grate, as well as control over furnace loads and transient conditions. The proposed BACT emission limit for the No. 4 Combination Boiler is 0.60 lb/MMBtu when firing bark/wood, equivalent to 307.62 lbs/hr (24-hour average) and 1,212.6 TPY, and 5 lbs/1,000 gallons for fuel oil firing, equivalent to 13.96 lbs/hr (24-hour average) and 12.5 TPY.

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

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

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

[a] To convert from lb/hr, the emission limit was divided by the throughput rate.
[b] Assuming 8,760 hr/yr.
[c] This information obtained from actual PSD permit, not Clearinghouse.

Table 5-2. CO Control Technology Feasibility Analysis for the No. 4 Combination Boiler

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

Note: NA = Not Applicable

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 GENERAL APPROACH

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

Generally, if the facility undergoing the modification is within 200 km of a PSD Class I area, then a significant impact analysis is also performed to evaluate the impact due to the project alone at the PSD Class I area. Because the Okefenokee, Wolf Island, and Chassahowitzka NWAs are PSD Class I areas that are located within 200 km of the Palatka Mill, the maximum predicted impacts due to the project at these PSD Class I areas are compared to EPA's proposed significant impact levels for PSD Class I areas. These recommended levels have never been promulgated as rules, but are the currently accepted criteria for determining whether a proposed project will incur a significant impact on a PSD Class I area.

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

If the project-only impacts at the PSD Class I area are above the proposed EPA PSD Class I significant impact levels, then an analysis is performed to address compliance with allowable PSD Class I increments at the PSD Class I area. The proposed project's maximum emission increases are also evaluated at the PSD Class I area to support the air quality related values (AQRV) analysis, which includes an evaluation of regional haze degradation.

Generally, when using 5 years of meteorological data for determining compliance with the AAQS and PSD Class II increments, the highest annual and the highest, second-highest (HSH) short-term (*i.e.*, 24 hours or less) concentrations are compared to the applicable AAQS and allowable PSD increments. For determining compliance with the 24-hour AAQS for PM, the sixth highest predicted concentration in 5 years (*i.e.*, H6H), instead of the HSH, is used to compare to the applicable 24-hour AAQS.

The HSH concentration is calculated for a receptor field by:

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

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

To develop the maximum short-term concentrations for the proposed project, the modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. For this study, the only difference between the two modeling phases is the density of the receptor grid spacing employed when predicting concentrations. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record.

If the original screening analysis indicates that the highest concentrations are occurring in a selected area(s) of the grid and, if the area's total coverage is too vast to directly apply a refined receptor grid, then an additional screening grid(s) is used over that area. The additional screening grid(s) employs a greater receptor density than the original screening grid.

Refinements of the maximum predicted concentrations are typically performed for the receptors of the screening receptor grid at which the highest and/or HSH concentrations occurred over the 5-year period. Generally, if the maximum concentrations from other years in the screening analysis are within 10 percent of the overall maximum concentration, then those other concentrations are refined as well. Typically, if the highest and HSH concentrations occur in different locations, concentrations in both areas are refined.

A more detailed description of the model, along with the emission inventory, meteorological data, and receptor grids, is presented in the following sections.

6.2 SIGNIFICANT IMPACT ANALYSIS

FDEP policies stipulate that the highest annual average and highest short-term concentrations are to be compared to the applicable significant impact levels both in the vicinity of the project and at the PSD Class I area. Based on the screening modeling analysis results in the vicinity of the project, additional modeling refinements are performed, if necessary, to obtain the maximum concentration with a receptor grid spacing of 100 m or less.

6.3 AAQS AND PSD CLASS II ANALYSES

For each pollutant for which a significant impact is predicted in the vicinity of the project, AAQS and PSD Class II increment consumption analyses are required. The AAQS analysis is a cumulative source analysis that evaluates whether the post-project concentrations from background sources will comply with the AAQS. Background sources include the post-project source configuration at the project site, the impacts from other nearby facility sources, plus a background concentration to account for sources not included in the modeling analysis.

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

6.4 PSD CLASS I ANALYSIS

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

6.5 MODEL SELECTION

The Industrial Source Complex Short-term (ISCST3, Version 02035) dispersion model (EPA, 2002) was used to evaluate the pollutant impacts due to the proposed project in areas within 50 km of the GP Palatka Mill. This model is maintained by EPA on its Internet website, Support Center for

Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). A listing of ISCST3 model features is presented in Table 6-1. The ISCST3 model is designed to calculate hourly concentrations based on hourly meteorological data (*i.e.*, wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The ISCST3 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. These areas are referred to as simple terrain. The model can also be applied in areas where the terrain exceeds the stack heights. These areas are referred to as complex terrain.

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The ISCST3 model can be executed in the rural or urban land use mode. The land use mode affects stability, dispersion coefficients, wind speed profiles, and mixing heights. Land use can be characterized based on a scheme recommended by EPA (Auer, 1978). If more than 50 percent of the land use within a 3-km radius around a project site is classified as industrial or commercial, or high-density residential, then the urban option should be selected. Otherwise, the rural option is appropriate. Based on the land use within a 3-km radius of the GP Palatka Mill site, the rural dispersion coefficients were used in the modeling analysis. Also, since the terrain around the facility is flat to gently rolling, the terrain in the vicinity of the Mill was assumed to be flat.

The ISCST3 model was used to provide maximum concentrations for the annual, 24-, 8-, 3-, and 1-hour averaging times.

For predicting maximum impacts at the Okefenokee, Chassahowitzka, and Wolf Island NWA PSD Class I areas, the California Puff (CALPUFF) modeling system was used. CALPUFF, Version 5.711a (beta/enhanced) (EPA, 2004), is a Lagrangian puff model that is the latest available that is required to be used by the Federal Land Manager (FLM) for the NWA, for predicting pollutant impacts at PSD Class I areas that are beyond 50 km from a project site. A description of the CALPUFF model is presented in Appendix B. A listing of CALPUFF model features is presented in Table 6-2.

6.6 METEOROLOGICAL DATA

Meteorological data used in the ISCST3 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations located at the Jacksonville International Airport and Waycross, Georgia, respectively. Concentrations were predicted using the 5-year period, 1984 through 1988. These data have been approved by FDEP for modeling applications in the Putnam County area. The NWS station at Jacksonville is located approximately 91 km (56 miles) north of the site and is the closest primary weather station to the study area considered to have meteorological data representative of the project site. The meteorological data from this station have been used for previous air modeling studies for the GP Palatka Mill.

The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling height. The wind speed, cloud cover, and cloud ceiling values were used in the ISCST3 meteorological preprocessor program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated from the radiosonde data at Waycross using the Holzworth approach (Holzworth, 1972). Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by EPA (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential, hourly meteorological data set (*i.e.*, wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions at the NWS stations are classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed using the EPA RAMMET meteorological preprocessor program.

A detailed discussion on meteorological data used in the CALPUFF model is presented in Appendix B.

6.7 EMISSION INVENTORY

6.7.1 SIGNIFICANT IMPACT ANALYSIS

The CO emission rates, and the physical and operational stack parameters for all project-affected sources used in the significant impact analysis, are presented in Tables 6-3 and 6-4. The current actual and future potential CO emissions for all GP Palatka Mill sources affected by the project are presented in Table 6-3. Emission rates are based on information presented in Section 2.0 and Appendix A. The stack and operating parameters used in the air modeling analysis for all project-affected GP sources are included in Table 6-4. As described in Section 2.0, the project-affected sources include the No. 4 Combination Boiler and the No. 4 Power Boiler. All sources were modeled at locations that are relative to the old TRS Incinerator stack location.

The proposed project's CO impacts were predicted to be below the PSD Class II significant impact levels. As such, AAQS analyses for CO with all other Mill and background emission sources were not required.

6.7.2 PSD CLASS I ANALYSIS

The CO emissions and modeling parameters used to address the project's impacts at the PSD Class I areas were the same as those used to determine the project's impacts in the vicinity of the GP Palatka Mill (see Subsection 6.7.1). The proposed project's CO emissions were evaluated at the Class I areas to support the AQRV analysis. The AQRV analyses for the Okefenokee and Wolf Island NWAs are presented in Section 8.0, while those for the Chassahowitzka NWA are presented in Section 9.0.

6.8 RECEPTOR LOCATIONS

6.8.1 SITE VICINITY

The screening receptor grid used for the site vicinity was comprised of more than 3,900 Cartesian receptors, and consisted of the following:

- Property boundary receptors, spaced at 50-m intervals;
- Receptors from the property boundary out to 2.0 km from the air modeling origin, spaced at 100-m intervals;
- Receptors from 2 to 3.5 km, spaced at 250-m intervals; and
- Receptors from 3.5 to 10 km, spaced at 500-m intervals.

All receptors are located with respect to the modeling origin. The modeling origin of the receptor grid was the old TRS incinerator stack location, and all source and receptor locations are relative to this location.

A summary of the property boundary receptors used in the modeling analysis is summarized in Table 6-5. The receptor locations in the vicinity of the plant are shown in Figure 6-1.

6.8.2 PSD CLASS I AREAS

Maximum CO concentrations for the project were predicted at the Okefenokee, Wolf Island, and Chassahowitzka NWAs with the CALPUFF model. The proposed project's maximum CO concentrations were evaluated at the Okefenokee NWA using 500 receptors; at Wolf Island NWA using 30 receptors; and on the boundary of the Chassahowitzka NWA using 58 receptors. These receptors were obtained from the National Park Service.

Because the project' SO_2, PM_{10}, and NO_2 emissions were less than the PSD significant emission rates and did not trigger PSD review, no additional analyses are required to assess the project's impacts in the PSD Class I areas. Modeling analyses are also not required to assess the project's impacts on regional haze or sulfur and nitrogen deposition since there is not a significant increase in emissions for pollutants that affect visibility impairment (i.e., SO_2, PM_{10}, or NO_2) or sulfur and nitrogen deposition (i.e., SO_2 or NO_2).

6.9 BUILDING DOWNWASH EFFECTS

All significant building structures within GP's existing plant area were determined by a site plot plan. The plot plan of the GP site was presented in Section 2.0 (Figure 2-1). A total of 12 building structures were evaluated. All structures were processed in the EPA Building Input Profile (BPIP, Version 95086) program to determine direction-specific building heights and projected widths for each 10-degree azimuth direction for each source that was included in the modeling analysis. A listing of dimensions for each structure is presented in Table 6-6. The current sources and building locations are shown in Figure 6-2.

6.10 MODEL RESULTS

6.10.1 SIGNIFICANT IMPACT ANALYSIS

A summary of the maximum CO concentrations predicted for the proposed project only is presented in Table 6-7. As shown in this table, the maximum CO concentrations are predicted to be below the respective significant impact levels. As a result, full modeling analyses for AAQS were not performed for CO.

6.10.2 PSD CLASS I ANALYSIS

Because the project's SO_2, PM_{10}, and NO_2 emissions were less than the PSD significant emission rates and did not trigger PSD review, PSD Class I increment consumption analyses were not required to be addressed in this application. Impacts of CO emissions due to the proposed project, on the PSD Class I areas, was evaluated. Results of this analysis are presented in Section 8.0.

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

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

Note: ISCST3 = Industrial Source Complex Short-Term.

References:

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Table 6-2. Major Features of the CALPUFF Model, Version 5.711a

CALPUFF Model Features

- Source types: Point, line (including buoyancy effects), volume, area (buoyant, non-buoyant).
- Non-steady-state emissions and meteorological conditions (time-dependent source and emission data; gridded 3-dimensional wind and temperature fields; spatially-variable fields of mixing heights, friction velocity, precipitation, Monin-Obukhov length; vertically and horizontally-varying turbulence and dispersion rates; time-dependent source and emission data for point, area, and volume sources; temporal or wind-dependent scaling factors for emission rates).
- Efficient sampling function (integrated puff formulation; elongated puff (slug) formation).
- Dispersion coefficient options (Pasquill-Gifford (PG) values for rural areas; McElroy-Pooler values (MP) for urban areas; CTDM values for neutral/stable; direct measurements or estimated values).
- Vertical wind shear (puff splitting; differential advection and dispersion).
- Plume rise (buoyant and momentum rise; stack-tip effects; building downwash effects; partial plume penetration above mixing layer).
- Building downwash effects (Huber-Snyder method; Schulman-Scire method).
- Complex terrain effects (steering effects in CALMET wind field; puff height adjustments using ISC model method or plume path coefficient; enhanced vertical dispersion used in CTDMPLUS).
- Subgrid scale complex terrain (CTSG option) (CTDM flow module; dividing streamline as in CTDMPLUS).
- Dry deposition (gases and particles; options for diurnal cycle per pollutant, space and time variations with a resistance model, or none).
- Overwater and coastal interaction effects (overwater boundary layer parameters; abrupt change in meteorological conditions, plume dispersion at coastal boundary; fumigation; option to use Thermal Internal Boundary Layers (TIBL) into coastal grid cells).
- Chemical transformation options (Pseudo-first-order chemical mechanisms for SO_2, sulfate (SO_4), HNO_3, and NO_3; Pseudo-first-order chemical mechanisms for SO_2, SO_4, NO, NO_2, HNO_3, and NO_3 (RIVAD/ARM3 method); user-specified diurnal cycles of transformation rates; no chemical conversions).
- Wet removal (scavenging coefficient approach; removal rate as a function of precipitation intensity and type).
- Graphical user interface.
- Interface utilities (scan ISCST3 and AUSPLUME meteorological data files for problems; translate ISCST3 and AUSPLUME input files to CALPUFF input files).

Note: CALPUFF = California Puff Model.

Source: EPA, 2004.

Table 6-3. Summary of Past Actual and Future Potential Emissions Used in the Significant Impact Analysis, Georgia-Pacific, Palatka

Pollutant/ Averaging Time	No. 4 Combination Boiler				No. 4 Power Boiler			
	Hourly		Annual		Hourly		Annual	
	lb/hr	g/s	TPY	g/s	lb/hr	g/s	TPY	g/s
			PAST ACTUAL EMISSIONS [a]					
CO--1-Hour	255.52	32.20	--	--	0.51	0.06	--	--
--8-Hour	255.52	32.20	--	--	0.51	0.06	--	--
			FUTURE POTENTIAL EMISSIONS [b]					
CO--1-Hour	307.62	38.76	--	--	0	0	--	--
--8-Hour	307.62	38.76	--	--	0	0	--	--

[a] Current actual emissions from Tables 2-1, A-5, A-6, and A-7.

[b] Future potential emissions from Table 2-2 and Tables A-1 through A-4. The No. 4 Power Boiler is being shutdown and therefore has zero emissions in the future.

Table 6-4. Stack and Operating Parameters and Locations for Project-Affected Sources Used in the Significant Impact Modeling Analysis for Georgia-Pacific, Palatka

		Relative Location [a]				Stack Parameters				Operating Parameters				
	Unit	x		y		Height		Diameter		Temperature		Flow Rate	Velocity	
Emission Unit	ID	(ft)	(m)	(ft)	(m)	(ft)	(m)	(ft)	(m)	(°F)	(K)	(acfm)	(ft/s)	(m/s)
No. 4 Combination Boiler	CB4	-331.9	-101.16	337.6	102.91	237	72.2	8.0	2.44	466	514	278,400	92.3	28.14
No. 4 Power Boiler	PB4	-280.8	-85.58	439.4	133.94	200.1	61.0	4.0	1.22	395	475	54,072	71.6	21.83
Old TRS Incinerator [b]	TRS	0	0	0	0	250	76.2	3.1	0.94	500	533	8,246	105.1	32.03

[a] Relative to old TRS Incinerator stack location and true north.

[b] The old TRS Incinerator will not be operational in the future, but stack parameters were incorporated into the modeling since it is used as the modeling origin.

Table 6-5. Property Boundary Receptors Used in the Modeling Analysis, Georgia-Pacific, Palatka

Coordinates (m)		Coordinates (m)		Coordinates (m)		Coordinates (m)		Coordinates (m)		Coordinates (m)		Coordinates (m)		Coordinates (m)	
x	y	x	y	x	y	x	y	x	y	x	y	x	y	x	y
-311.0	-1781.0	-3231.4	-279.6	-4162.2	2413.6	-3944.5	3977.0	-1217.8	4808.0	1914.3	4492.0	1574.6	2851.9	1248.5	842.0
-402.0	-1739.6	-3331.4	-276.3	-4168.3	2513.4	-4044.5	3977.0	-1117.8	4808.6	1911.6	4392.0	1527.7	2763.6	1348.5	842.0
-493.1	-1698.2	-3431.3	-273.0	-4174.5	2613.3	-4144.5	3977.0	-1017.8	4809.3	1908.9	4292.0	1480.8	2675.3	1448.5	842.0
-584.1	-1656.9	-3531.3	-269.7	-4180.6	2713.1	-4185.0	4036.5	-917.8	4809.9	1906.3	4192.1	1433.9	2587.0	1548.5	842.0
-675.1	-1615.5	-3631.2	-266.4	-4186.8	2812.9	-4185.0	4136.5	-817.8	4810.5	1903.6	4092.1	1341.7	2574.0	1648.5	842.0
-766.2	-1574.1	-3731.1	-263.1	-4193.0	2912.7	-4185.0	4236.5	-717.8	4811.2	1826.1	4069.0	1241.7	2574.0	1740.2	832.5
-857.2	-1532.7	-3831.1	-259.8	-4199.1	3012.5	-4161.5	4313.4	-617.8	4811.8	1739.0	4081.9	1141.7	2574.0	1737.6	740.0
-948.3	-1491.3	-3931.0	-256.5	-4205.3	3112.3	-4061.5	4315.0	-517.8	4812.5	1739.0	4181.9	1116.1	2482.6	1657.5	680.0
-1039.3	-1450.0	-3894.6	-190.3	-4211.4	3212.1	-3961.5	4316.6	-417.8	4813.1	1739.0	4281.9	1095.9	2384.7	1577.5	620.1
-1130.3	-1408.6	-3832.3	-112.1	-4217.6	3311.9	-3861.6	4318.3	-317.8	4813.7	1739.0	4381.9	1075.6	2286.8	1497.4	560.2
-1221.4	-1367.2	-3769.9	-33.9	-4176.6	3360.5	-3761.6	4319.9	-217.8	4814.4	1739.0	4481.9	1055.4	2188.8	1417.4	500.2
-1312.4	-1325.8	-3707.6	44.3	-4077.7	3346.0	-3661.6	4321.5	-117.8	4815.0	1739.0	4581.9	1035.1	2090.9	1337.3	440.3
-1403.4	-1284.4	-3651.2	125.9	-3978.8	3331.6	-3561.6	4323.2	-17.9	4815.7	1739.0	4681.9	1033.7	2027.3	1257.3	380.4
-1494.5	-1243.1	-3613.9	218.7	-3879.8	3317.1	-3461.6	4324.8	82.1	4816.3	1642.1	4685.0	1105.3	2097.0	1177.2	320.4
-1585.5	-1201.7	-3576.7	311.5	-3780.9	3302.6	-3361.6	4326.4	182.1	4816.9	1542.1	4685.0	1177.0	2166.7	1097.2	260.5
-1676.5	-1160.3	-3562.9	403.3	-3681.9	3288.1	-3261.6	4328.1	282.1	4817.6	1442.1	4685.0	1248.7	2236.4	1017.1	200.6
-1767.6	-1118.9	-3608.6	492.2	-3583.0	3273.7	-3161.6	4329.7	382.1	4818.2	1410.0	4624.5	1320.4	2306.2	937.1	140.6
-1858.6	-1077.5	-3654.2	581.2	-3484.0	3259.2	-3087.4	4349.2	482.1	4818.9	1421.4	4525.2	1392.1	2375.9	857.0	80.7
-1949.7	-1036.2	-3732.9	616.0	-3385.1	3244.7	-3120.8	4443.5	582.1	4819.5	1432.8	4425.8	1466.0	2440.6	777.0	20.7
-2040.7	-994.8	-3832.9	616.0	-3286.1	3230.2	-3154.1	4537.8	682.1	4820.1	1444.3	4326.5	1565.7	2448.5	696.9	-39.2
-2131.7	-953.4	-3924.1	634.0	-3187.2	3215.8	-3187.4	4632.1	782.1	4820.8	1455.7	4227.1	1615.7	2396.7	616.9	-99.1
-2222.8	-912.0	-3985.8	712.8	-3088.2	3201.3	-3220.7	4726.4	882.1	4821.4	1467.2	4127.8	1625.9	2297.2	536.8	-159.1
-2313.8	-870.6	-4039.0	789.7	-2989.3	3186.8	-3217.8	4795.2	982.1	4822.1	1478.6	4028.4	1636.0	2197.8	456.8	-219.0
-2404.8	-829.3	-3951.2	837.5	-2890.3	3172.3	-3117.8	4795.8	1082.1	4822.7	1490.0	3929.1	1646.2	2098.3	376.7	-278.9
-2495.9	-787.9	-3863.4	885.4	-2806.0	3174.8	-3017.8	4796.5	1182.1	4823.3	1551.6	3886.0	1656.4	1998.8	296.7	-338.9
-2586.9	-746.5	-3831.0	966.1	-2806.0	3274.8	-2917.8	4797.1	1282.1	4824.0	1651.6	3886.0	1666.6	1899.3	216.6	-398.8
-2678.0	-705.1	-3831.0	1066.1	-2806.0	3374.8	-2817.8	4797.7	1382.1	4824.6	1751.6	3886.0	1676.8	1799.8	169.7	-483.4
-2769.0	-663.7	-3899.1	1098.0	-2806.0	3474.8	-2717.8	4798.4	1482.1	4825.3	1851.6	3886.0	1687.0	1700.4	134.9	-577.2
-2860.0	-622.4	-3999.1	1098.0	-2806.0	3574.8	-2617.8	4799.0	1582.1	4825.9	1951.6	3886.0	1625.4	1642.7	100.2	-671.0
-2940.6	-573.9	-4082.1	1116.1	-2806.0	3674.8	-2517.8	4799.7	1682.1	4826.5	2051.6	3886.0	1537.4	1600.6	65.5	-764.7
-2945.1	-474.0	-4088.3	1215.9	-2806.0	3774.8	-2417.8	4800.3	1782.1	4827.2	2076.0	3837.1	1549.7	1501.3	30.7	-858.5
-2949.7	-374.1	-4094.4	1315.7	-2860.4	3831.0	-2317.8	4800.9	1882.1	4827.8	2034.9	3745.9	1562.0	1402.1	-4.0	-952.3
-2954.3	-274.2	-4100.6	1415.5	-2958.1	3852.7	-2217.8	4801.6	1982.1	4828.5	1993.9	3654.8	1617.3	1369.0	-38.8	-1046.1
-2958.8	-174.3	-4106.8	1515.3	-3055.7	3874.3	-2117.8	4802.2	2082.1	4829.1	1952.8	3563.6	1696.5	1367.8	-73.5	-1139.8
-2963.4	-74.4	-4112.9	1615.2	-3153.4	3895.9	-2017.8	4802.9	2182.1	4829.7	1911.7	3472.4	1723.6	1271.6	-108.2	-1233.6
-2968.0	25.5	-4119.1	1715.0	-3251.0	3917.5	-1917.8	4803.5	2282.1	4830.4	1940.0	3383.5	1641.3	1229.4	-143.0	-1327.4
-3004.4	92.0	-4125.2	1814.8	-3348.6	3939.1	-1817.8	4804.1	2376.0	4830.1	1924.8	3291.7	1548.4	1192.5	-177.7	-1421.1
-3104.4	92.0	-4131.4	1914.6	-3446.3	3960.7	-1717.8	4804.8	2280.4	4801.0	1875.8	3209.6	1457.8	1152.2	-212.4	-1514.9
-3190.0	77.6	-4137.5	2014.4	-3544.5	3977.0	-1617.8	4805.4	2184.7	4771.8	1787.8	3162.1	1389.9	1078.8	-247.2	-1608.7
-3190.0	-22.4	-4143.7	2114.2	-3644.5	3977.0	-1517.8	4806.1	2107.3	4712.3	1699.8	3114.6	1322.0	1005.4	-281.9	-1702.5
-3190.0	-122.4	-4149.9	2214.0	-3744.5	3977.0	-1417.8	4806.7	2036.6	4641.6	1654.9	3033.7	1254.1	931.9		
-3190.0	-222.4	-4156.0	2313.8	-3844.5	3977.0	-1317.8	4807.3	1965.9	4570.9	1621.5	2940.2	1186.2	858.5		

Note: All coordinates are relative to old TRS incinerator stack location.

Table 6-6. Structure Dimensions Used in the Modeling Analysis, Georgia-Pacific, Palatka

Structure	Height		Length		Width	
	(ft)	(m)	(ft)	(m)	(ft)	(m)
RB4 Precipitator	85	25.9	123	37.5	58	17.6
RB4 Boiler Building	193.7	59.0	104	31.7	90	27.4
Power Plant Building	107.6	32.8	101	30.8	92	28.0
Pulp Dryer No. 3	84.5	25.8	275	83.7	157	47.9
Pulp Dryer No. 5	70.5	21.5	328	99.9	99	30.3
Pulp Dryer No. 4	73	22.3	265	80.7	125	38.2
Roll Storage Building	52	15.8	464	141.4	346	105.5
Tissue Converting & Finishing (White)	84	25.6	298	90.8	207	63.1
Towel & Napkin Warehouse (Green)	33.5	10.2	434	132.3	424	129.2
Towel & Napkin Converting & Finishing (Yellow)	48	14.6	377	114.9	422	128.6
Towel & Napkin Warehouse (Blue)	40	12.2	464	141.4	641	195.4
Towel & Napkin Warehouse (Gray)	28	8.5	434	132.3	481	146.6
Converting Operations	48	14.6	47	14.3	65	19.8
Building 63	40	12.2	134	40.8	148	45.1
Warehouse Complex 1	62.67	19.1	1,394	424.9	377	114.8
Warehouse Complex 2	46.8	14.3	924	281.5	425	129.5
Nos. 1 and 2 Machines Storage	71.16	21.7	225	68.6	407	124.2
Kraft Converting and Storage	60.75	18.5	310	94.4	524	159.9
Kraft Warehouse and Multi-Wall	56.7	17.3	290	88.4	521	158.7
Digester	62.2	19.0	264	80.4	33	10.1
No. 3 RB Building [a]	100	30.5	61	18.6	34	10.4
No. 2 RB Building [a]	100	30.5	58	17.7	73	22.3

[a] 1974 Baseline Only

Table 6-7. Maximum Predicted Pollutant Impacts for the Project Compared to the EPA PSD Class II Significant Impact Levels

Pollutant/ Averaging Time	Concentration [a] (ug/m^3)	Receptor Location [b] x (m)	Receptor Location [b] y (m)	Time Period (YYMMDDHH) [c]	EPA Significant Impact Level (ug/m^3)
CO					
8-Hour	3.50	1,600.0	-800.0	84040616	500
	3.37	1,900.0	-300.0	85021208	
	2.63	1,600.0	400.0	86060816	
	3.57	536.8	-159.1	87120416	
	4.03	456.8	-219.0	88040716	
1-Hour	15.56	400.0	-300.0	84052412	2,000
	16.14	456.8	-219.0	85091013	
	16.24	456.8	-219.0	86060212	
	15.29	500.0	-200.0	87012302	
	16.08	500.0	-200.0	88080712	

[a] Based on 5-year surface and upper air meteorological data for 1984 to 1988 from the National Weather Serv Stations in Jacksonville and Waycross, respectively.

[b] Relative to the old TRS Incinerator stack.

[c] YYMMDDHH = Year, Month, Day, Hour Ending

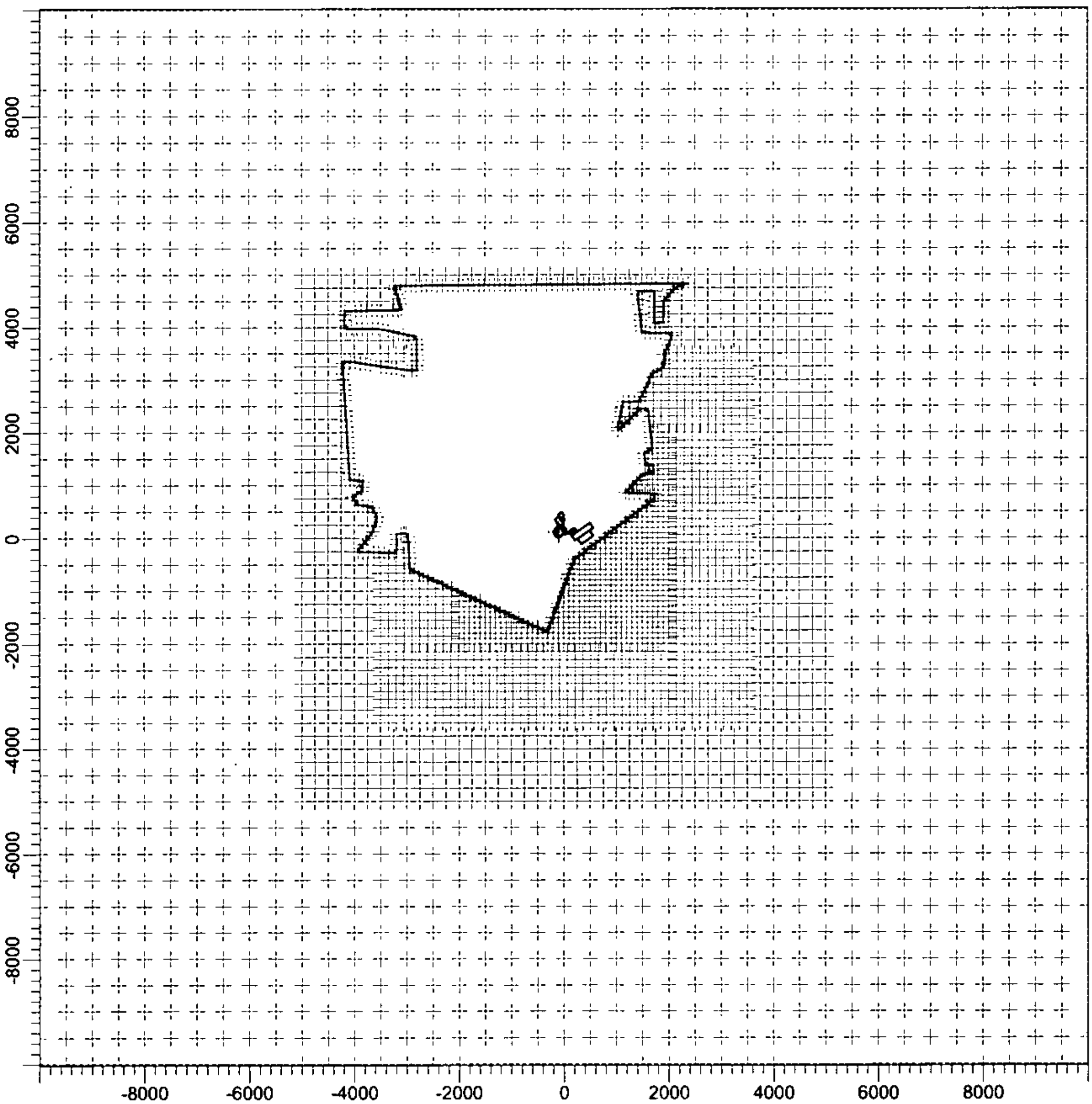

Figure 6-1
Property Boundary and Offsite Receptor Locations

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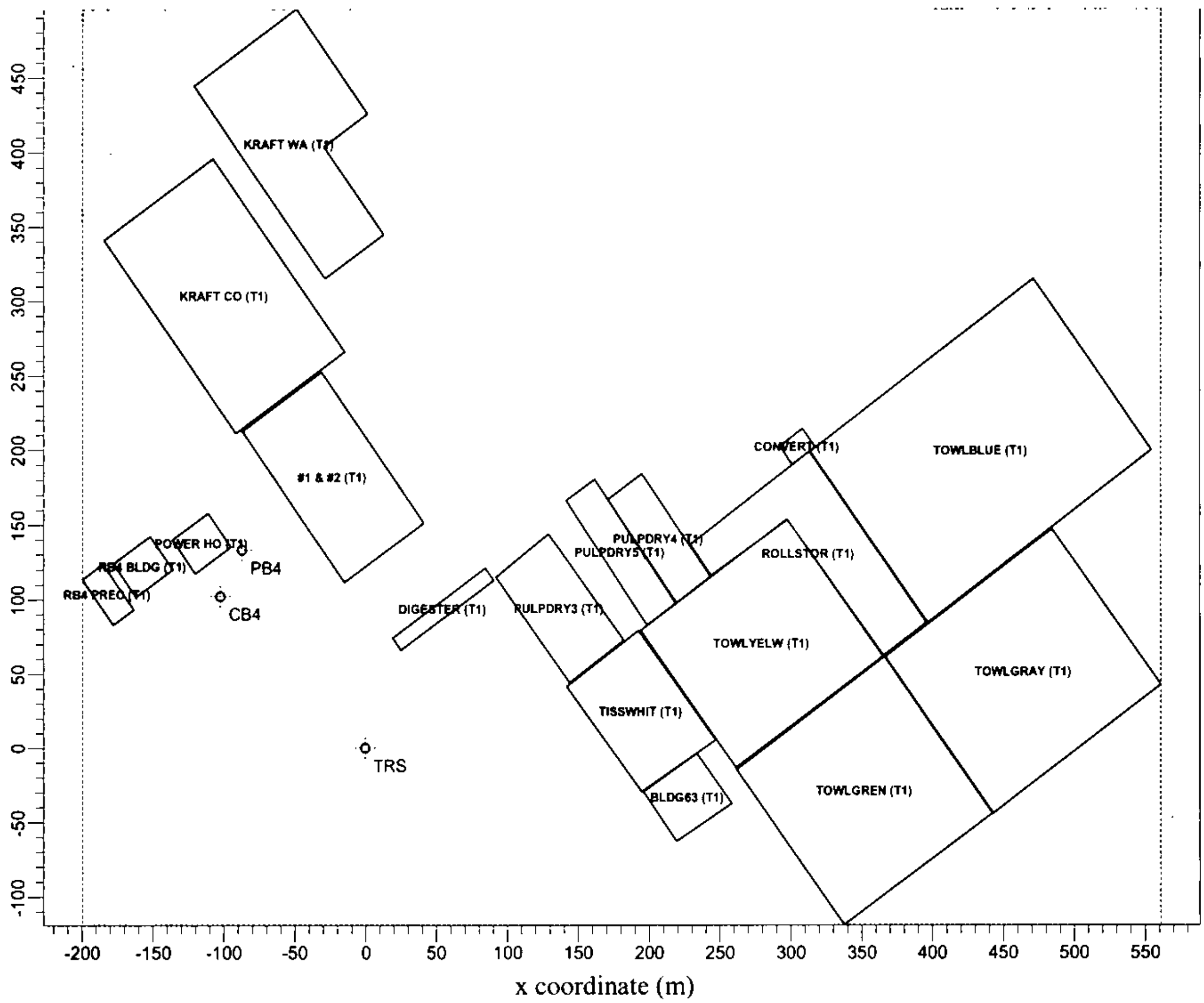


Note: Units are in meters (m).

Figure 6-2
Building and Stack Locations

Golder Associates

7.0 ADDITIONAL IMPACT ANALYSIS FOR THE VICINITY OF THE GP PALATKA MILL

7.1 IMPACTS TO SOILS, VEGETATION, AND VISIBILITY IN THE VICINITY OF THE GP PALATKA MILL

7.1.1 PREDICTED AIR QUALITY IMPACTS

The results of the ambient air quality modeling for the proposed GP modification, in the vicinity of the plant, are presented in Table 7-1. The predicted maximum increase in CO concentrations due to the proposed project are presented for the annual, 24-hour, 8-hour, 3-hour, and 1-hour averaging times.

7.1.2 IMPACTS TO SOILS

Air contaminants can affect soils through fumigation by gaseous forms, accumulation of compounds transformed from the gaseous state, or by the direct deposition of PM or PM to which certain contaminants are absorbed. According to the Putnam County Soil Survey (1990), the soils in the vicinity of the GP Palatka Mill are dominated by Terra Ceia muck, with Cassia fine sand and Pamona fine sand also present. The Terra Ceia muck, Cassia fine sand, and Pomona fine sand series are described in the Putnam County Soil Survey as follows:

Terra Ceia muck, frequently flooded – This soil is nearly level and very poorly drained, found on broad to narrow plains along the St. Johns River and its tributaries. Typically the upper part of this organic soil is dark reddish brown muck approximately 28 inches thick, while the lower portion to a depth of approximately 80 inches is black muck. This soil has a high water table at the surface except during extended dry periods. The available water capacity is very high, permeability is rapid, and natural fertility is moderate. Typical vegetation includes wetlands forested with sweetgum, red maple, cypress, bay, and cabbage palm. The soil reaction for Terra Ceia muck is classified as slightly acidic within the top 28 inches, and mildly alkaline between 28 and 80 inches below the surface.

Pomona fine sand – This soil is nearly level and poorly drained, found in broad flatwoods areas. Typically this soil has a surface layer of black fine sand approximately 6 inches thick underlain by a subsurface layer of gray and light gray fine sand to a depth of 20 inches. In most years this soil has a high water table at a depth of less than 12 inches for 1 to 3 months. The available water capacity is very low, permeability is rapid, and natural fertility is low. Typical vegetation is pine flatwoods. The soil reaction for Pomona fine sand is classified as extremely acidic within the top 6 inches, very strongly acidic between 6 to 10 inches, and strongly acidic between 10 and 20 inches below the surface.

Cassia fine sand – This soil is nearly level and somewhat poorly drained, found on small knolls within flatwoods and in low positions on uplands. Typically, this soil has a surface layer of gray fine sand approximately 4 inches thick, and a subsurface layer of light gray fine sand to a depth of 28 inches. In most years, this soil has a water table at a depth of 15 to 40 inches for about 6 months. The available water capacity is very low, permeability is rapid, and natural fertility is low. Natural vegetation includes pine flatwoods and oak. Cassia fine sand is classified as extremely acidic within the top 4 inches, very strongly acidic between 4 to 9 inches, and strongly acidic between 9 and 24 inches below the surface.

The dominant soil in the vicinity of the GP facility, Terra Ceia muck, is a highly organic wetland soil and has an extremely high buffering capacity based on the cation exchange capacity, base saturation, and bulk density. Therefore, this soil would be relatively insensitive to atmospheric inputs. The maximum predicted CO concentrations in the vicinity of the site as a result of the proposed project are less than the significant impact levels. Therefore, no detrimental effects on soils should occur in the vicinity of the GP Palatka Mill due to the proposed project.

7.1.3 IMPACTS TO VEGETATION

7.1.3.1 Vegetation Analysis

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from minor air contaminants, such as fluorides, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides, have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury", as opposed to damage, is commonly used to describe all plant responses to air contaminants and is used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

Injury to vegetation from exposure to various levels or air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant.

Carbon Monoxide

CO has not been found to produce detrimental effects on plants at concentrations below 100 ppm (114,500 $\mu g/m^3$) for exposures from 1 to 3 weeks (EPA, 1976). The predicted maximum concentrations shown in Table 7-1 are well below levels reported to cause detrimental effects.

7.1.4 IMPACTS UPON VISIBILITY

All air emission sources affected by the proposed modification are existing sources. No increase in permitted emissions is requested, and actual PM/PM_{10}, NO_x, and SO_2 emissions will not increase by significant amounts. All these sources are in compliance with opacity regulations and should remain in compliance after the modification. As a result, no adverse impacts upon visibility are expected.

7.2 IMPACTS DUE TO ASSOCIATED DIRECT GROWTH

7.2.1 INTRODUCTION

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

In general, there has been minimal growth in the GP Palatka Mill area since 1977. Putnam County is surrounded by Marion County to the south and west, Alachua County to the west, Clay County to the north, St. John's County to the north and east, Flagler County to the east, and Volusia County to the south. Putnam County encompasses an 827-square mile area including 733-square miles of land area.

The No. 4 Combination Boiler is being modified to increase the actual bark/wood burning rate and to reduce fuel oil consumption. Additional growth as a direct result of the proposed modification is not expected.

Construction of the project (modification of the No. 4 Combination Boiler) will occur over a 3- to 4-month period, requiring an average of approximately 40 to 50 workers during that time. It is anticipated that many of these construction personnel will commute to the site. The project will not require any additional operational workers once the project is completed.

There are also expected to be no air quality impacts due to associated commercial and industrial growth given the location of the existing GP Palatka Mill. The existing commercial and industrial infrastructure should be adequate to provide any support services that the project might require and would not increase with the operation of the project.

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

7.2.2 RESIDENTIAL GROWTH

7.2.2.1 Population and Household Trends

As an indicator of residential growth, the trend in the population and number of household units in Putnam County since 1977 are shown in Figure 7-1. The County experienced a 47-percent increase in population during the period 1977 through 2000. During this period, there was an increase in population of about 22,600. Similarly, the number of households in the County increased by about 12,000, or 73 percent, since 1977.

7.2.2.2 Growth Associated with the Operation of the Project

Because there will be no additional workers needed to operate the project, there will be no residential growth due to the project.

7.2.3 COMMERCIAL GROWTH

7.2.3.1 Retail Trade and Wholesale Trade

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

Since 1977, retail trade has increased by about 14 establishments and 2,000 employees or 6 and 118 percent, respectively. For the same period, wholesale trade has increased by 28 establishments and 346 employees, or 82 and 126 percent, respectively.

7.2.3.2 Labor Force

The trend in the labor force in Putnam County since 1977 is shown in Figure 7-3. The greatest number of persons employed in Putnam County has been in the manufacturing, government, and retail trade sectors. Between 1977 and 1999, approximately 5,000 persons were added to the available work force, for an increase of 34 percent.

7.2.3.3 Tourism

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

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

Between 1978 and 2000, there was a decrease of 12 percent in the number of hotels and motels, and an increase of 14 percent in the number of units at those establishments that remained in the County.

7.2.3.4 Transportation

As an indicator of transportation growth, the trend in the number of vehicle miles traveled (VMT) by motor vehicles on major roadways in Putnam County is presented in Figure 7-5. The County's main roadways are U.S. Route 17 and SR 100.

Between 1977 and 2001, there was an increase of about 1,560,000 VMT per year, or 113 percent, on major roadways in the County.

7.2.3.5 Growth Associated with the Operation of the Project

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

7.2.4 INDUSTRIAL GROWTH

7.2.4.1 Manufacturing and Agricultural Industries

As an indicator of industrial growth, the trend in the number of employees in the manufacturing industry in Putnam County since 1977 is shown in Figure 7-6. As shown, the manufacturing industry experienced a slight decrease in employees from 1977 through 2000.

As another indicator of industrial growth, the trend in the number of employees reported in the agricultural industry in Putnam County since 1977 is also shown in Figure 7-6. As shown, the agricultural industry experienced an increase of about 400 employees from 1977 through 2000.

7.2.4.2 Utilities

Existing power plants in Putnam County include the following:

- Florida Power & Light's Putnam Plant;
- Seminole Electric Cooperative, Inc.'s Seminole Power Plant; and
- Georgia-Pacific Corporation's Palatka Operations.

Together, these power plants have an electrical nameplate generating capacity of over 1,800 megawatts (MW).

As an indicator of electrical utility growth, the electrical nameplate generating capacity in Putnam County since 1977 is shown in Figure 7-7. As shown, the electrical nameplate generating capacity has increased by 1,585 MW, or 521 percent since 1977.

7.2.4.3 Growth Associated with the Operation of the Project

Since the PSD baseline date of August 7, 1977, there has been only one major facility built within a 35-km radius of the GP Palatka Mill site. This was the Seminole Electric Power Plant. There are a limited number of facilities located throughout the 35-km radius area surrounding the site. Based on the locations of nearby air emission sources, there has not been a concentration of industrial and commercial growth in the vicinity of the GP Palatka Mill site.

7.2.5 AIR QUALITY DISCUSSION

7.2.5.1 Air Emissions

Based on actual emissions reported for 1999 (latest year of available data) by EPA on its AIRSdata website, total CO emissions from stationary sources in Putnam County are 4,640 TPY.

7.2.5.2 Air Emissions from Mobile Sources

The trends in the air emissions of CO from mobile sources in Putnam County are presented in Figure 7-8. Between 1977 and 2002, there were significant decreases in CO emissions. The decrease in CO emissions was about 41 tons per day, which represent a decrease from 1977 emissions of 48 percent.

7.2.5.3 Air Monitoring Data

Since 1977, Putnam County has been classified as attainment for all criteria pollutants. Air quality monitoring data have been collected in Putnam County, primarily in the central portion of the County in and around the City of Palatka. For this evaluation, the air quality monitoring data collected at the monitoring station nearest to the GP Palatka Mill were used to assess air quality trends since 1977. Air quality monitoring data were based on the following monitoring station:

- CO concentrations – Jacksonville

Data collected from this station are considered to be generally representative of air quality in Putnam County. Because the CO monitoring station in Jacksonville is located in a more urbanized area than the GP Palatka Mill, the reported concentrations for this station are likely to be higher than those experienced at the site.

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

7.2.5.4 CO Concentrations

The trends in the 1-hour and 8-hour average CO concentrations measured since 1977 in Jacksonville are presented in Figures 7-9 and 7-10, respectively. As shown in these figures, measured CO concentrations have been well below the AAQS for the past several years.

7.2.5.5 Air Quality Associated with the Operation of the Project

The CO air quality data measured in the region of the GP Palatka Mill indicate that the maximum air quality concentrations are well below and comply with the AAQS. Also, based on the trends presented, the air quality has generally improved in the region since the baseline date of August 7, 1977. Because the maximum concentrations for the proposed modification at the Mill are predicted to be below the significant impact levels, air quality concentrations in the region are expected to remain below and comply with the AAQS when the project becomes operational.

Table 7-1. Summary of Maximum CO Concentrations Predicted for the Project to Address Impacts to Soils and Vegetation in the GP Mill Vicinity

Averaging Time[a]	Concentration[b] ($\mu g/m^3$)	Receptor Location[c] x (m)	y (m)	Time Period[d] YYMMYYHH
Annual	0.12	1,900.0	-1,100.0	87123124
24-hour	2.08	1,800.0	-300.0	85021224
8-hour	4.03	456.8	-219.0	88040716
3-hour	10.3	500.0	-300.0	88040715
1-hour	16.2	456.8	-219.0	86060212

[a] Based on modeling the No. 4 Combination Boiler and No. 4 Power Boiler.

[b] Based on the highest concentrations predicted from modeling the 5-year period of 1984 to 1988.

[c] Relative to the old TRS Incinerator stack.

[d] YY = Year; MM = Month; DD = Day; HH = Hour ending.

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

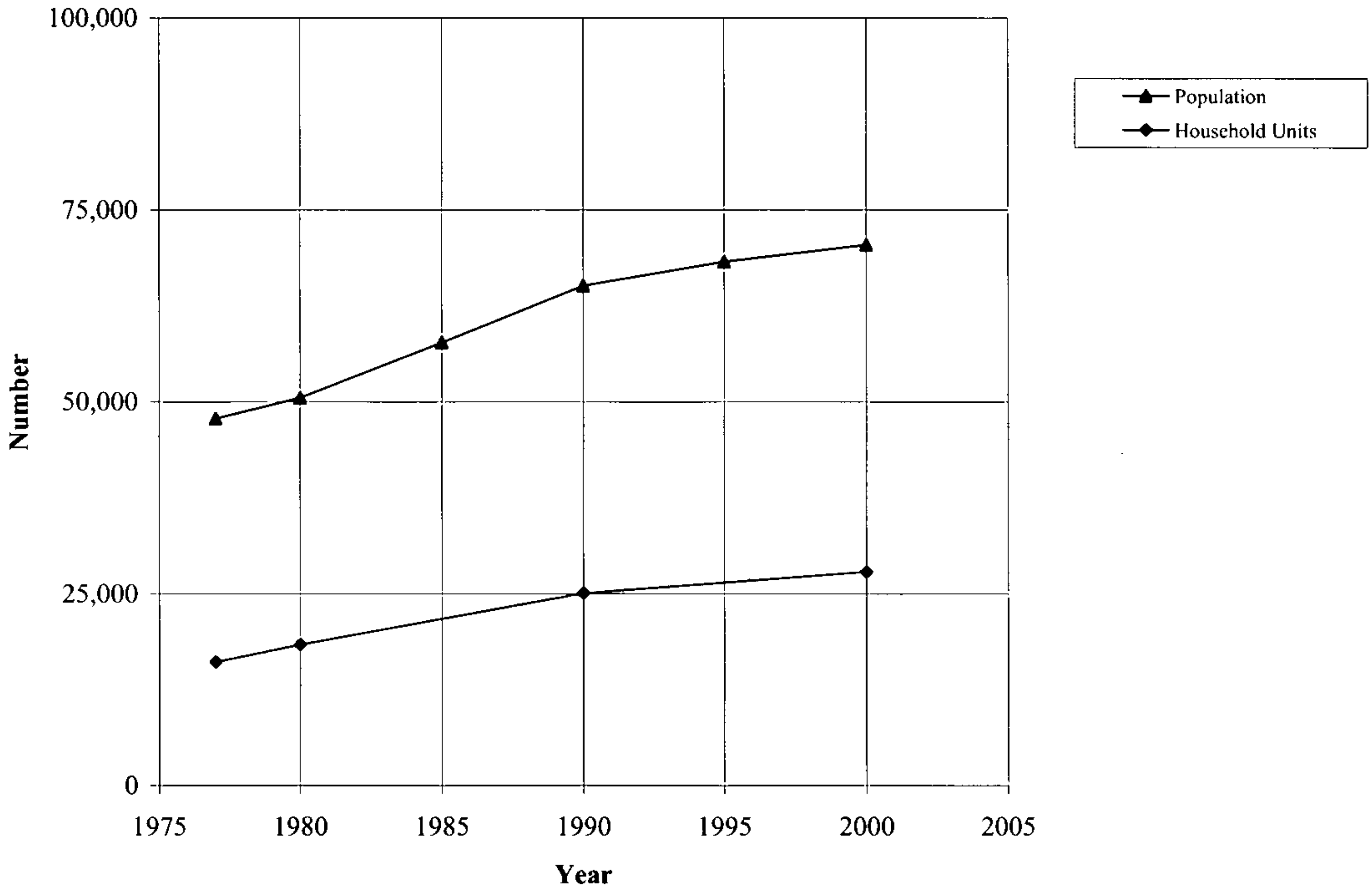


Figure 7-2. Retail and Wholesale Trade Trends in Putnam County

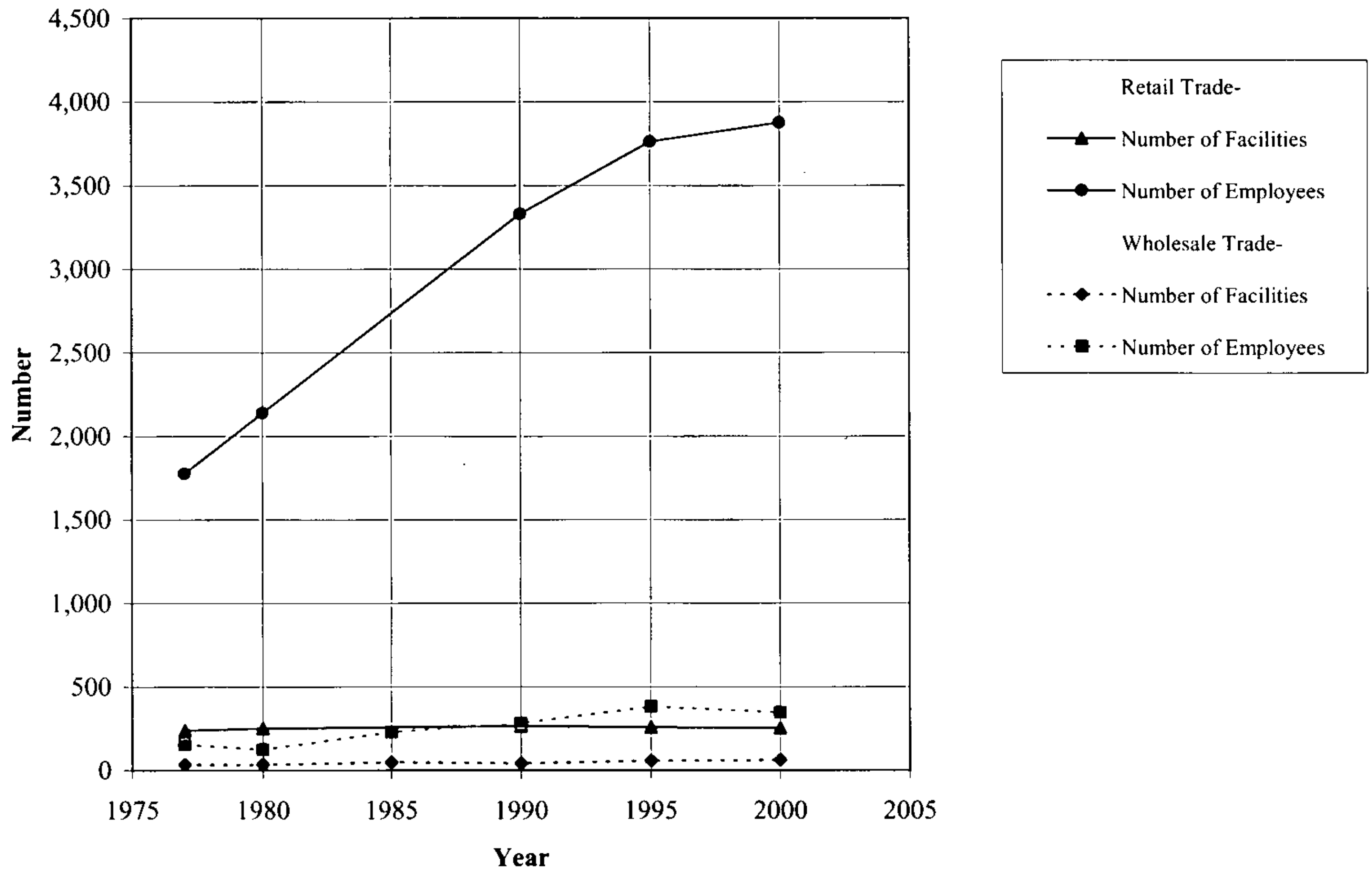


Figure 7-3. Labor Force Trend in Putnam County

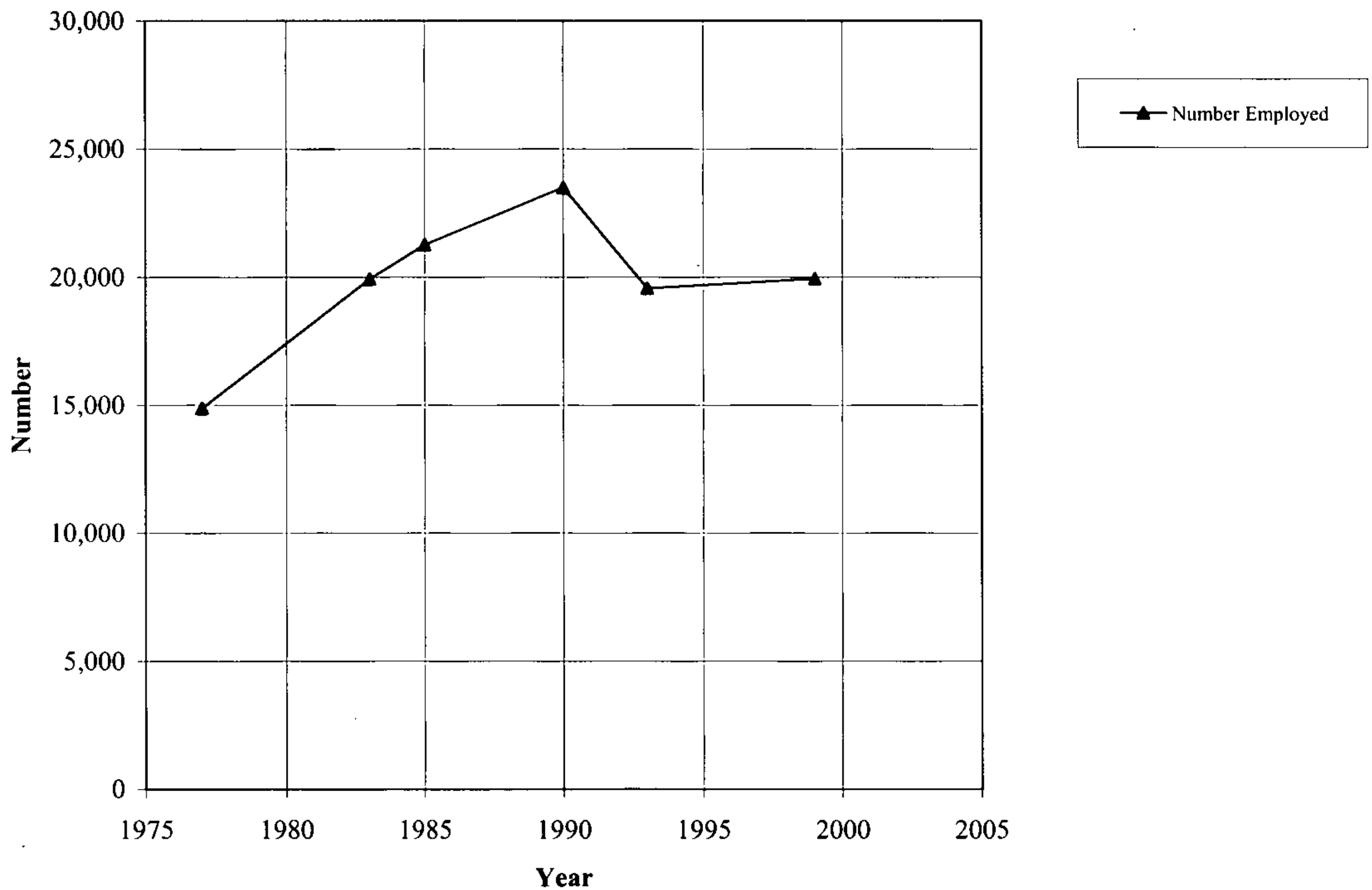


Figure 7-4. Hotel and Motel Trend in Putnam County

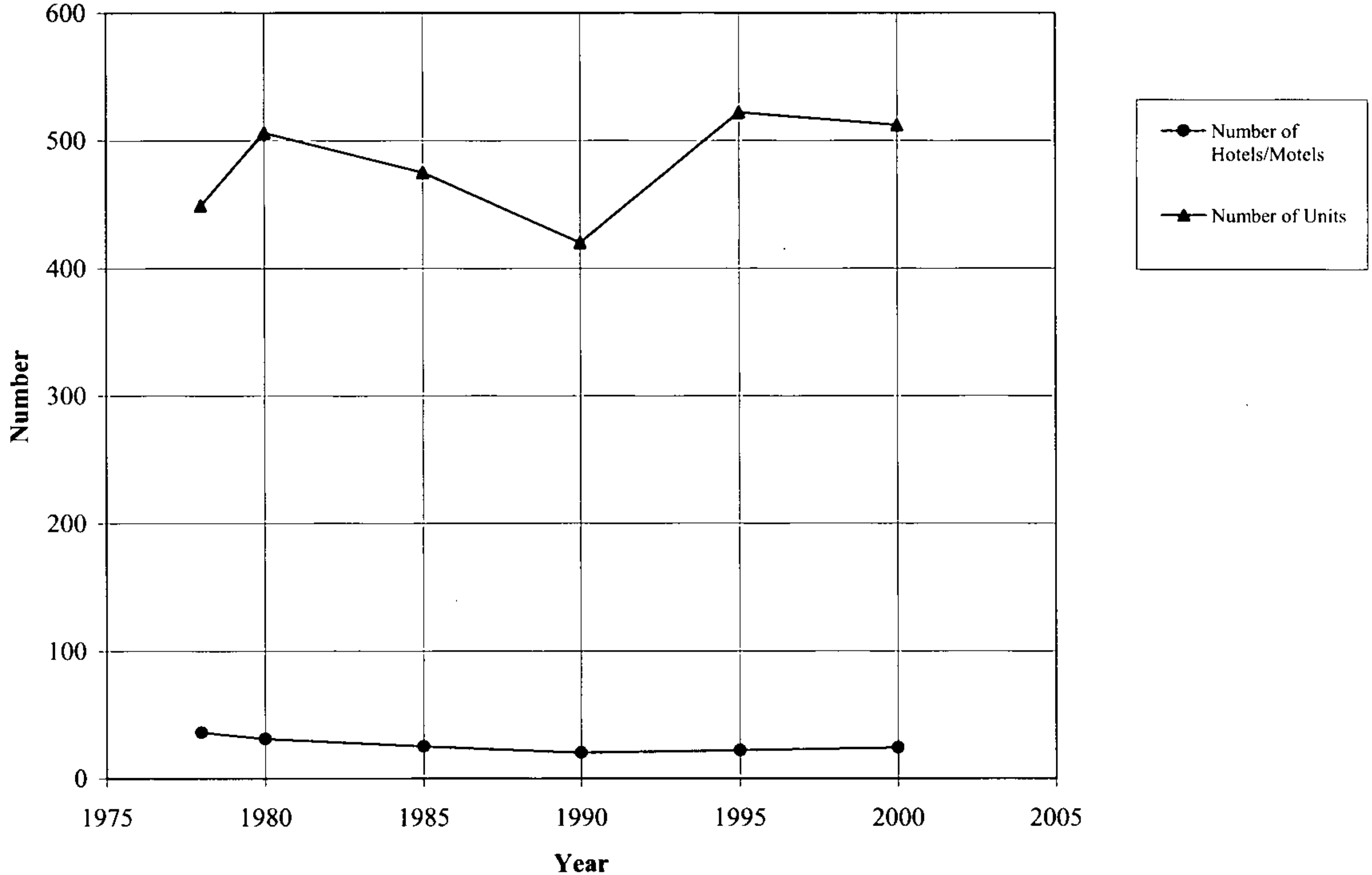


Figure 7-5. Vehicle Miles Traveled (VMT) Estimates for Motor Vehicles in Putnam County

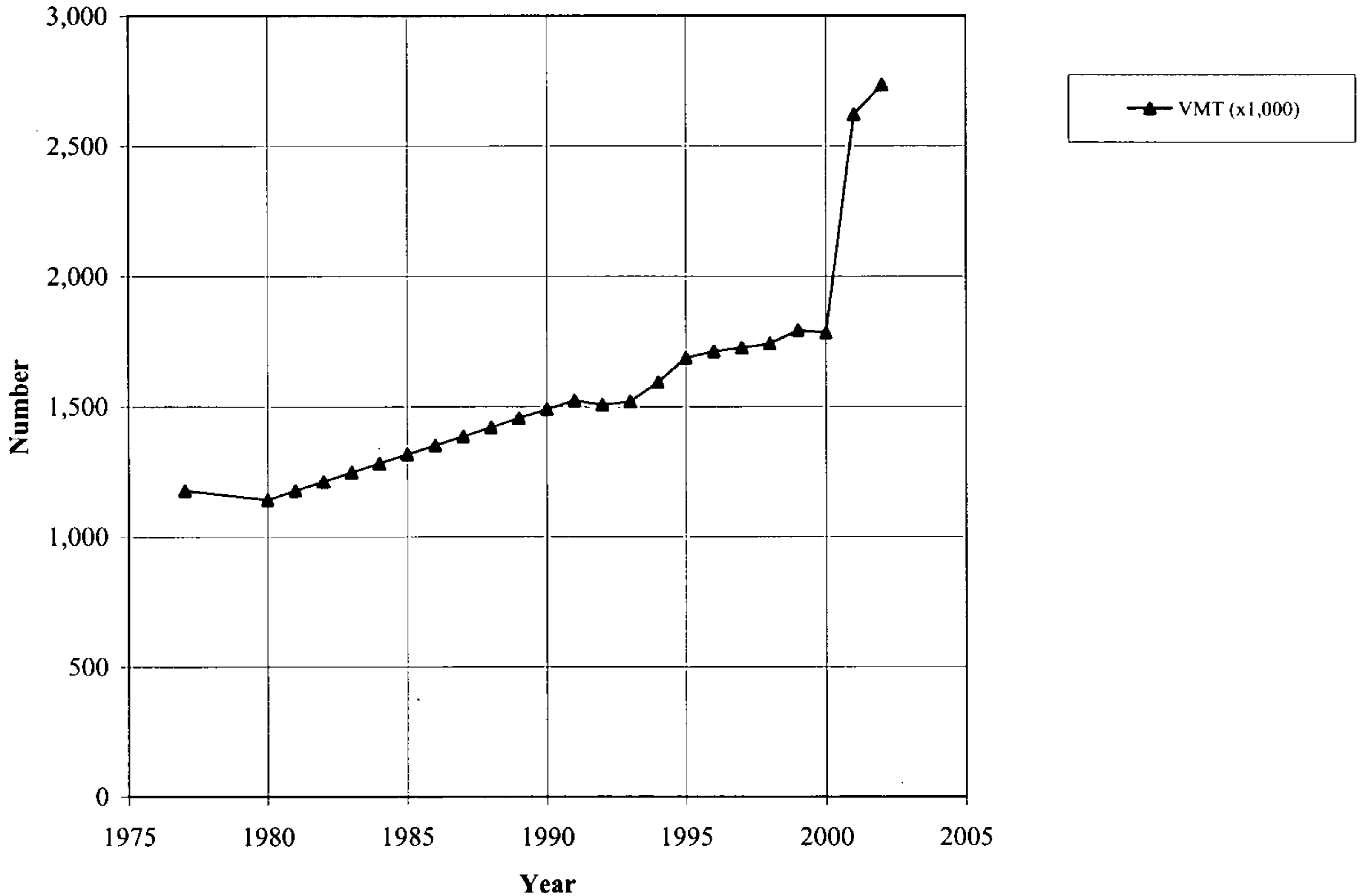
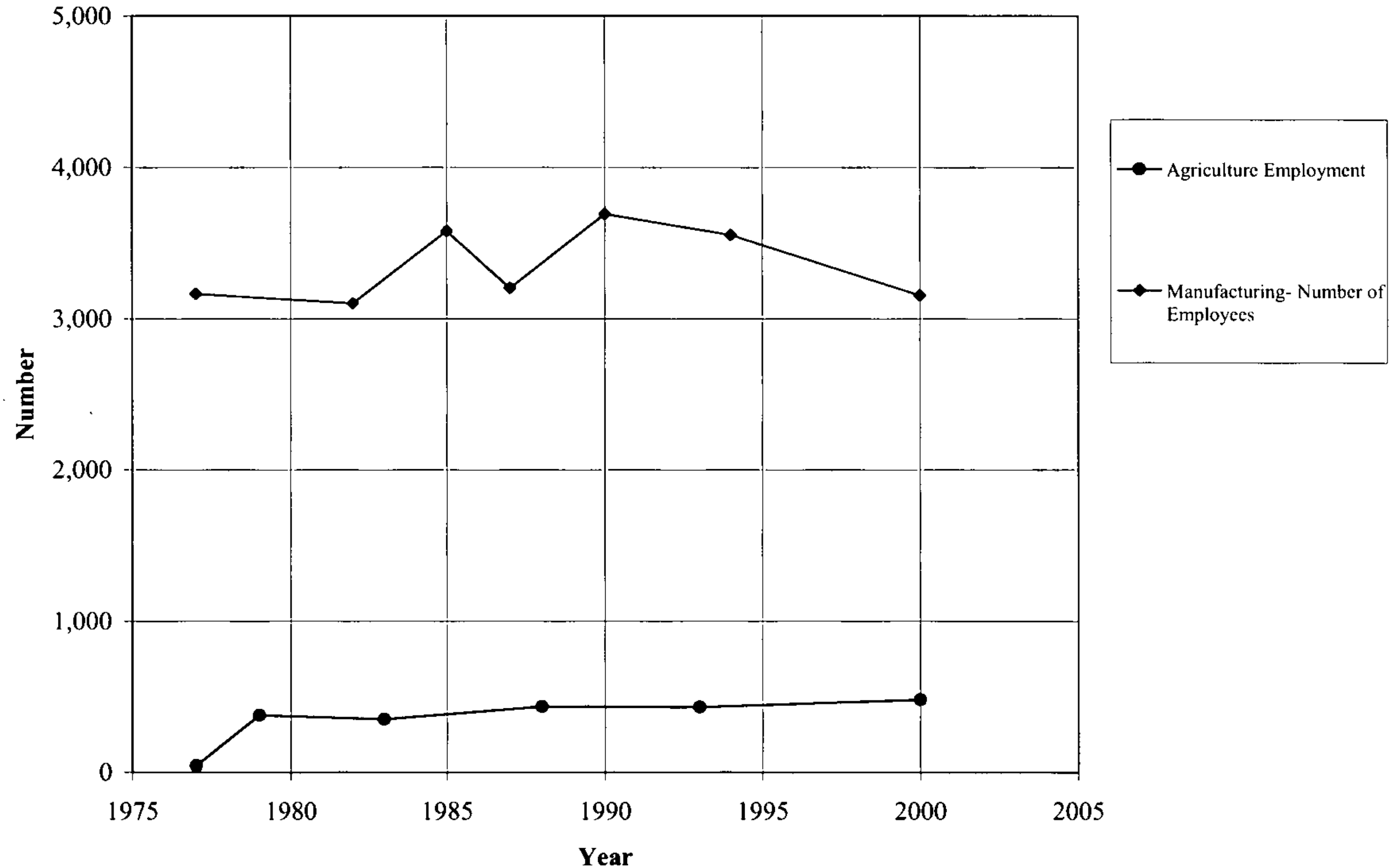


Figure 7-6. Manufacturing and Agriculture Trends in Putnam County



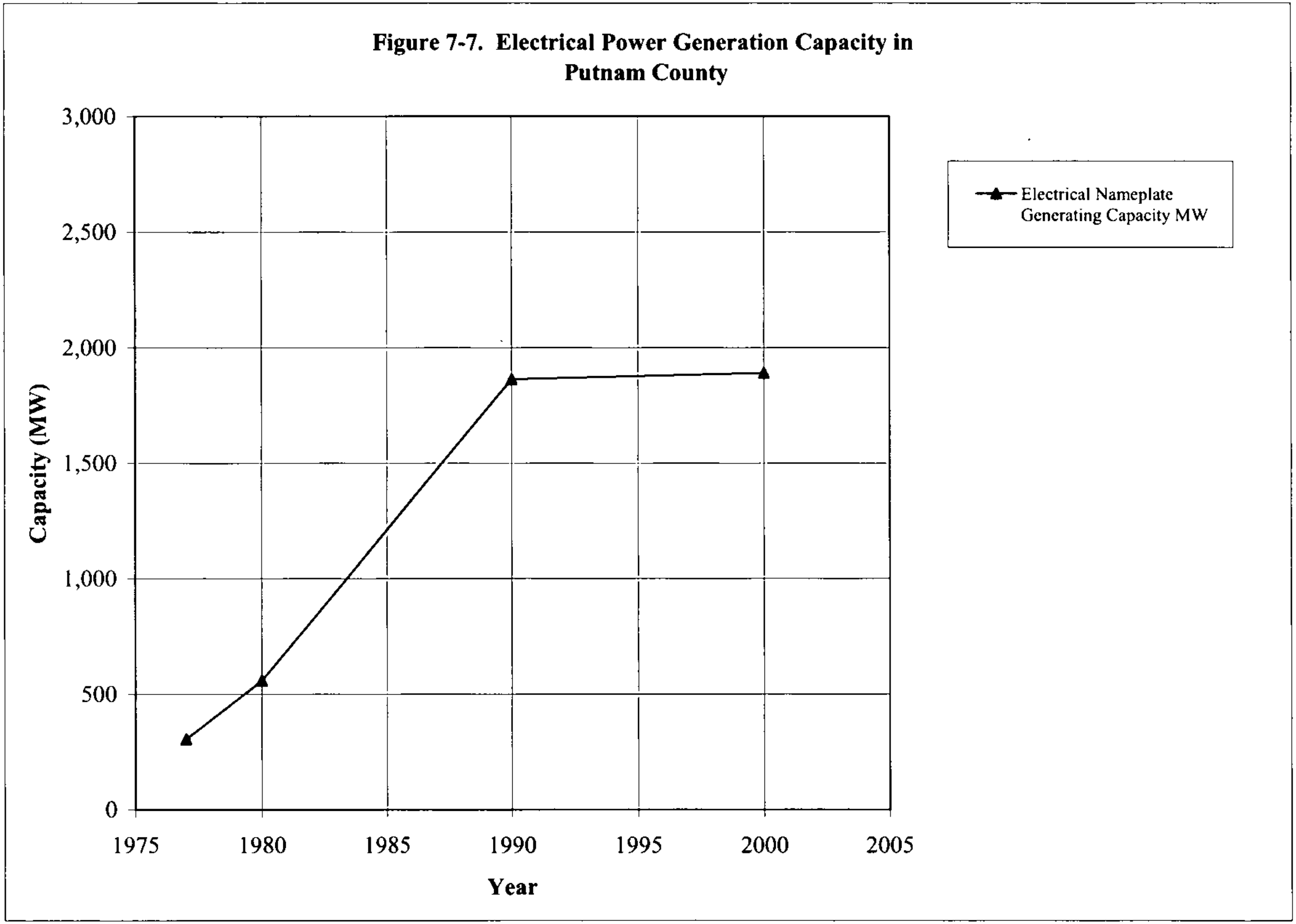


Figure 7-7. Electrical Power Generation Capacity in Putnam County
Capacity (MW)
3,000
2,500
2,000
1,500
1,000
500
0
1975
1980
1985
1990
1995
2000
2005
Year
Electrical Nameplate Generating Capacity MW

Figure 7-8. Mobile Source Emissions of CO (Tons per Day) in Putnam County

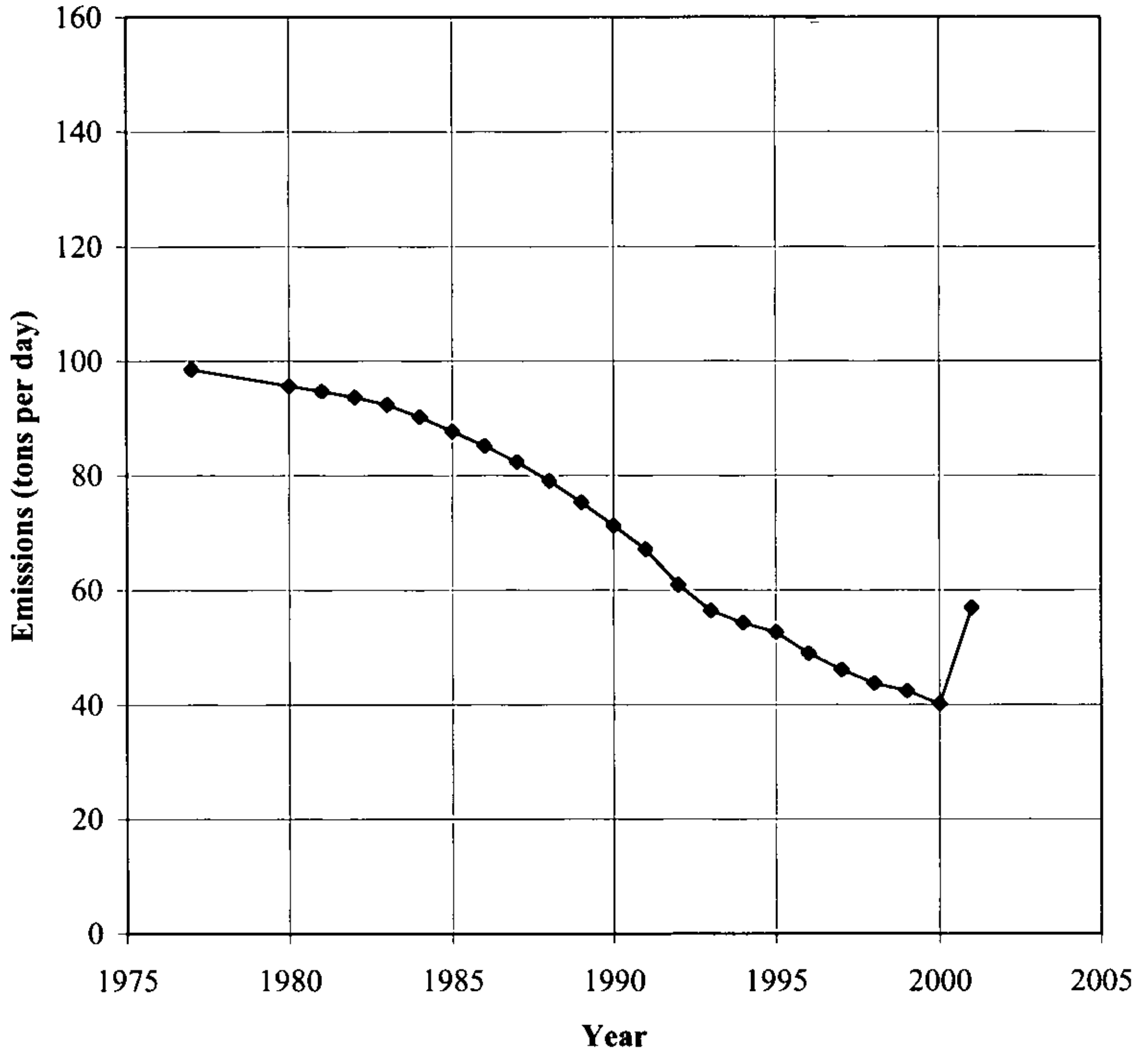


Figure 7-9. Measured 1-Hour Average Carbon Monoxide Concentrations (2nd Highest Values) from 1981 to 2002 - Putnam County

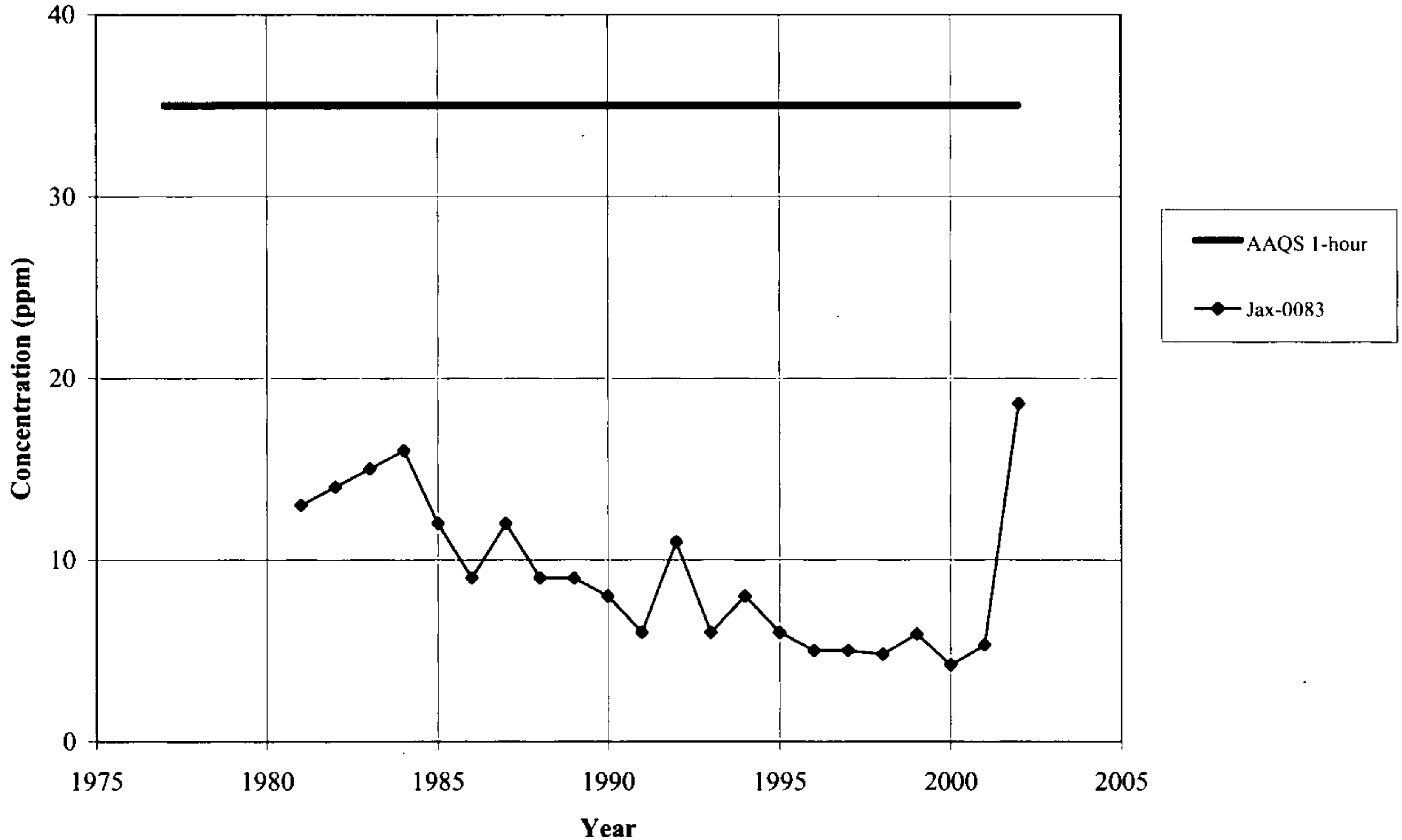
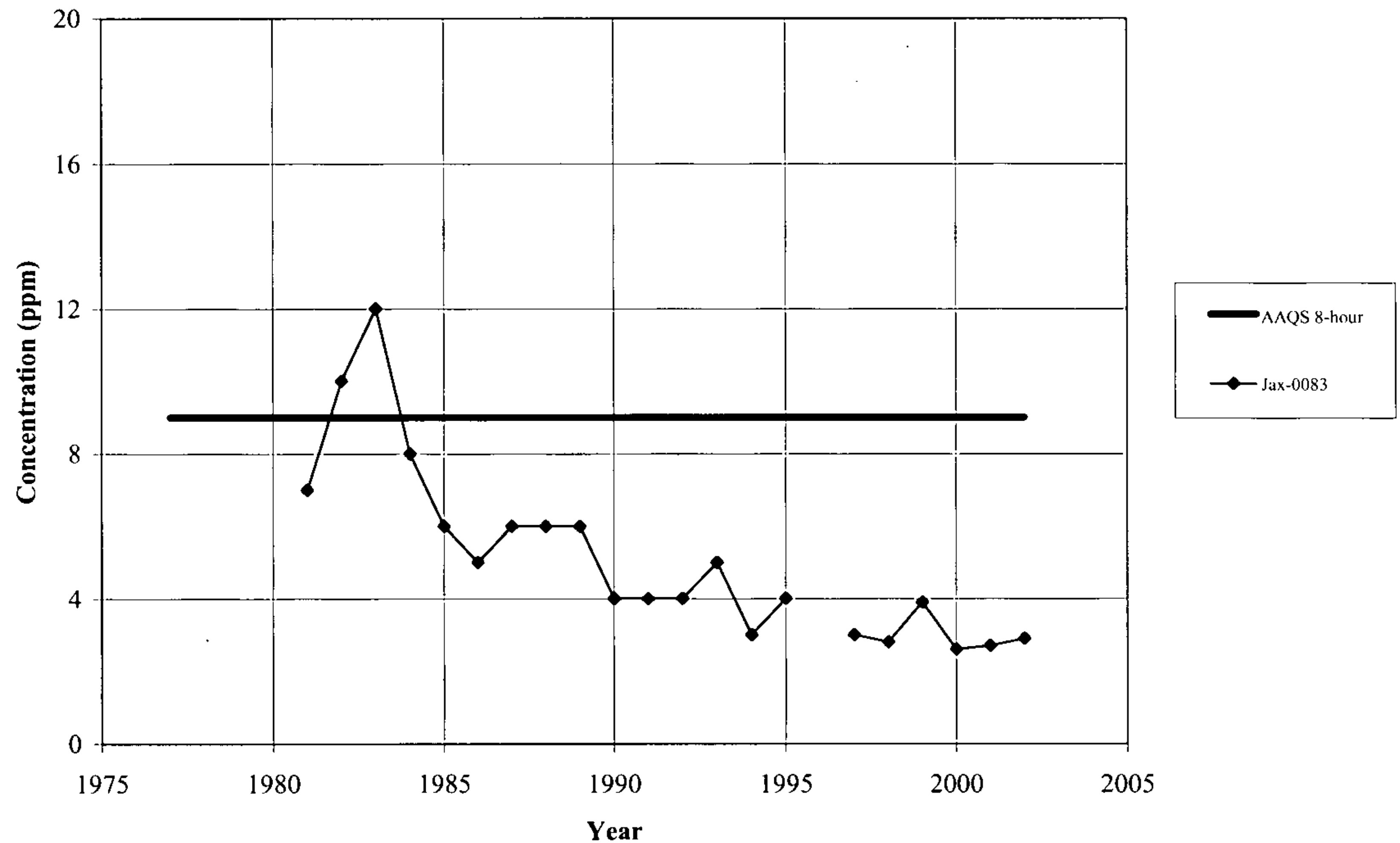


Figure 7-10. Measured 8-Hour Average Carbon Monoxide Concentrations (2nd Highest Values) from 1981 to 2002 - Putnam County



8.0 ADDITIONAL IMPACT ANALYSIS ON THE CLASS I AREAS

8.1 INTRODUCTION

GP has proposed changes to its pulp and paper mill located in Putnam County, near Palatka, Florida. The changes were described in Section 2.0. The facility is subject to the PSD new source review requirements for CO only.

This analysis addresses the potential impacts of increased CO emissions due to the project on vegetation, soils, and wildlife of the Okefenokee, Wolf Island, and Chassahowitzka NWA Class I areas. The Okefenokee NWA Class I area is located approximately 108 km north of the GP Palatka Mill, while the Wolf Island NWA Class I area is located approximately 186 km north of the GP Palatka Mill. Both NWAs have similar AQRVs. The Chassahowitzka NWA is located approximately 137 km southwest of the GP Palatka Mill.

The analysis demonstrates that the increase in impacts due to the proposed project is extremely low. Regardless of the existing conditions in the vicinity of the Class I areas, the proposed project will not cause any significant adverse effects due to the predicted low impacts upon those areas. Potential impacts upon visibility and sulfur and nitrogen levels resulting from the proposed project are not assessed since the project's emissions of SO_2, PM_{10}, and NO_x are less than the PSD significant emission rates.

8.2 SOILS, VEGETATION, AND AQRV ANALYSIS METHODOLOGY

This analysis uses the maximum CO air quality impacts predicted to occur for the project in the Class I areas due to the proposed increase in CO emissions. These impacts are summarized in Tables 8-1, 8-2, and 8-3, based on the modeling described in Section 6.0.

The analysis involved predicting worst-case maximum short- and long-term concentrations of pollutants in the Class I areas and comparing the maximum predicted concentrations to the lowest observed effect levels for AQRVs or analogous organisms. In conducting the assessment, several assumptions were made as to how pollutants interact with the different matrices, (*i.e.*, vegetation, soils, wildlife, and aquatic environment).

A screening approach was used to evaluate potential effects by comparison of the maximum predicted ambient concentrations with effect threshold limits for the pollutants of concern, for both vegetation and wildlife, as reported in the scientific literature. A literature search was conducted which specifically addressed the effects of air contaminants on plant species reported to occur in the vicinity of the GP Mill and the Class I areas. It is recognized that effects threshold information is not available for all species found in the Class I areas, although studies have been performed on other similar species that may be used as models.

8.3 IDENTIFICATION OF AQRVS AND METHODOLOGY

An AQRV analysis was conducted to assess the potential risk to AQRVs at the Okefenokee, Wolf Island, and Chassahowitzka NWAs due to the proposed GP project. The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

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

Except for visibility, AQRVs were not specifically defined. However, odor, soil, flora, fauna, cultural resources, geological features, water, and climate generally have been identified by FLMs as AQRVs. Since specific AQRVs have not been identified for these Class I areas, this AQRV analysis evaluates the effects of air quality on general vegetation types and wildlife found in the Class I areas.

8.3.1 OKEFENOKEE AND WOLF ISLAND

Vegetation type AQRVs and their representative species types have been defined as:

- Freshwater Marsh – sawgrass, pickerelweed, and sand cordgrass
- Marsh Islands – cabbage palm and eastern red cedar
- Estuarine Habitat – black needlerush, salt marsh cordgrass, and wax myrtle
- Hardwood Swamp – red maple, red bay, sweet bay, and cabbage palm

- Upland Forests – live oak, scrub oak, longleaf pine, slash pine, wax myrtle, and saw palmetto

Wildlife AQRVs have been identified as endangered species, waterfowl, wading birds, shorebirds, reptiles, and mammals.

The maximum CO concentrations predicted for the project in the Okefenokee and Wolf Island NWAs are presented in Tables 8-1 and 8-2, respectively. These results were compared with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. While the literature search focused on such species as cabbage palm, eastern red cedar, lichens, and species of the hardwood swamplands and mangrove forest, no specific citations that addressed these species were found. Threshold information is not available for all species found in the Class I areas, although studies have been performed on a few of the common species and on other similar species that can be used as indicators of effects.

8.3.2 CHASSAHOWITZKA

Vegetation type AQRVs and their representative species types for Chassahowitzka have been defined by the USFWS as:

- Marshlands – black needlerush, sawgrass, salt grass, and salt marsh cordgrass
- Marsh Islands – cabbage palm and eastern red cedar
- Estuarine Habitat – black needlerush, salt marsh cordgrass, and wax myrtle
- Hardwood Swamp – red maple, red bay, sweet bay, and cabbage palm
- Upland Forests – live oak, scrub oak, longleaf pine, slash pine, wax myrtle, and saw palmetto
- Mangrove Swamp – red, white, and black mangrove

Wildlife AQRVs have been identified as endangered species, waterfowl, marsh and water birds, shore birds, reptiles, and mammals.

The maximum CO concentrations predicted for the project in the Chassahowitzka NWA are presented in Table 8-3. These results were compared with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted that specifically addressed the effects of air contaminants on plant species reported to occur in the Chassahowitzka

NWA. While the literature search focused on such species as cabbage palm, eastern red cedar, lichens, and species of the hardwood swamp lands and mangrove forest, no specific citations that addressed these species were found. It is recognized that effect threshold information is not available for all species found in the Chassahowitzka NWA, although studies have been performed on a few of the common species and on other similar species that can be used as indicators of effects.

8.4 IMPACTS TO SOILS

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

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

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

8.4.1 OKEFENOKEE AND WOLF ISLAND

The soils of the Okefenokee NWA are generally classified as histosols. Histosols (peat soils) are organic and have extremely high buffering capacities based on their CEC, base saturation, and bulk density. Therefore, they would be relatively insensitive to atmospheric inputs.

The majority of the soil complexes found in the Wolf Island NWA are inundated by tidal waters, contain a relatively high organic matter content, and have high buffering capacities based on their CEC, base saturation, and bulk density. The regular flooding of these soils regulates the pH and any change in acidity in the soil would be buffered by this activity. Therefore, they would be relatively insensitive to atmospheric inputs.

The relatively low sensitivity of the soils to atmospheric inputs coupled with the extremely low ground-level pollutant concentrations due to the project for the Okefenokee and Wolf Island NWAs precludes any significant impact on soils.

8.4.2 CHASSAHOWITZKA

The soils of the Chassahowitzka NWA are generally classified as histosols. According to the U.S. Department of Agriculture (USDA) Soil Surveys of Citrus and Hernando Counties, nine soil complexes are found in the Chassahowitzka NWA. These include Aripeka fine sand, Aripeka-Okeelanta-Lauderhill, Hallendale-Rock outcrop, Homosassa mucky fine sandy loam, Lacoochee, Okeelanta mucks, Okeelanta-Lauderdale-Terra Ceia mucks, Rock outcrop-Homosassa-Lacoochee, and Weekiwachee-Durbin mucks (Porter, 1996). The majority of the soil complexes found in the Chassahowitzka NWA are inundated by tidal waters, contain a relatively high organic matter content, and have high buffering capacities based on their CEC, base saturation, and bulk density. The regular flooding of these soils by the Gulf of Mexico regulates the pH and any change in acidity in the soil would be buffered by this activity. Therefore, they would be relatively insensitive to atmospheric inputs. However, Terra Ceia, Okeelanta, and Lauderdale freshwater mucks are present along the eastern border of the Chassahowitzka NWA, and may be more sensitive to atmospheric sulfur deposition (Porter, 1996). Although not tidally influenced, these freshwater mucks are highly organic and, therefore, have a relatively high intrinsic buffering capacity.

The relatively low sensitivity of the soils to atmospheric inputs coupled with the extremely low ground-level pollutant concentrations due to the project at the Chassahowitzka NWA precludes any significant impact on soils.

8.5 <u>IMPACTS TO VEGETATION</u>

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM_{10}. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury", as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure.

Injury to vegetation from exposure to various levels or air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation. This is a conservative approach.

The response of vegetation and wildlife to atmospheric pollutants is influenced by the concentration of the pollutant, duration of exposure, and frequency of exposures. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration which occur during certain meteorological conditions interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants or animals, they will likely arise from the short-term, higher doses. A dose is the product of the concentration of the pollutant and duration of the exposure.

8.5.1 CARBON MONOXIDE

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

8.5.1.1 <u>Okefenokee and Wolf Island</u>

By comparison of published effect values for CO exposure, the possibility of plant damage in the Class I areas can be determined. The maximum 1-hour (most conservative) estimated CO concentration due to the increase in emissions resulting from the proposed project in the Okefenokee and Wolf Island NWA Class I areas is 0.402 $\mu g/m^3$ (see Tables 8-1 and 8-2). This concentration is less than 0.00001 percent of the value that caused inhibition in laboratory studies. The amount of damage sustained at this level (if any) for 1 hour would have negligible effects over an entire growing season. The predicted maximum annual CO concentration of 0.0032 μg/m^3 reflects a more realistic (yet conservative) CO level for the Class I area. This concentration is less than 0.000001 percent of the value that caused cytochrome *c* oxidase inhibition.

8.5.1.2 Chassahowitzka

By comparison of published effect values for CO exposure, the possibility of plant damage in the Class I area can be determined. The maximum 1-hour (most conservative) estimated CO concentration due to the increase in emissions resulting from the proposed project in the Chassahowitzka NWA Class I area is 0.260 μg/m^3 (see Table 8-3). This concentration is less than 0.00001 percent of the value that caused inhibition in laboratory studies. The amount of damage sustained at this level (if any) for 1 hour would have negligible effects over an entire growing season. The predicted maximum annual CO concentration of 0.0020 μg/m^3 reflects a more realistic (yet conservative) CO level for the Class I area. This concentration is less than 0.000001 percent of the value that caused cytochrome *c* oxidase inhibition.

8.5.2 SUMMARY

In summary, the phytotoxic effects from the project's emissions are minimal. It is important to note that the elements were conservatively modeled with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

8.6 IMPACTS TO WILDLIFE

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

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

No effects on wildlife AQRVs from CO are expected. The proposed project's contribution to cumulative impacts is expected to be negligible.

Table 8-1. Summary of Maximum CO Concentrations Predicted for the Project at the Okefenokee NWA PSD Class I Area

Averaging Time	Highest Concentration [a] (μg/m³)	Receptor UTM Location (km) East	Receptor UTM Location (km) North	Time Period [b] (Year/Day/ Ending Time)
Annual	0.00300	386.9	3381.5	90123124
	0.00270	386.9	3381.5	92123124
	0.00320	385.3	3381.5	96123124
24-hour	0.0547	386.9	3381.5	90081424
	0.0649	390.2	3390.7	92060324
	0.0694	385.3	3381.5	96032624
8-hour	0.0884	390.1	3385.2	90021416
	0.1093	377.3	3383.5	92112408
	0.1613	386.9	3381.5	96032608
3-hour	0.216	375.7	3383.5	90021506
	0.275	375.7	3383.5	92112406
	0.361	386.9	3381.5	96032606
1-hour	0.278	380.5	3383.4	90021506
	0.330	375.7	3383.5	92112406
	0.402	386.9	3381.5	96032604

Note: UTM = Universal Transverse Mercator.

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

[b] YY = Year; MM = Month; DD = Day; HH = Hour ending.

Table 8-2. Summary of Maximum CO Concentrations Predicted for the Project at the Wolf Island NWA PSD Class I Area

Averaging Time	Highest Concentration [a] (μg/m³)	Receptor UTM Location (km) East	Receptor UTM Location (km) North	Time Period [b] (Year/Day/Ending Time)
Annual	0.00150	471.1	3463.2	90123124
	0.00190	471.1	3463.2	92123124
	0.00130	471.8	3463.2	96123124
24-hour	0.0244	471.8	3463.2	90071124
	0.0439	468.7	3469.6	92031824
	0.0176	471.8	3463.2	96052124
8-hour	0.0523	471.1	3463.2	90033108
	0.0547	468.7	3469.6	92031816
	0.0382	471.8	3463.2	96052108
3-hour	0.132	471.8	3463.2	90033109
	0.121	468.7	3469.6	92031809
	0.139	471.8	3463.2	96120706
1-hour	0.168	468.7	3469.6	90012419
	0.136	468.7	3469.6	92031808
	0.194	471.8	3463.2	96120705

Note: UTM = Universal Transverse Mercator.

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

[b] YY = Year; MM = Month; DD = Day; HH = Hour ending.

Table 8-3. Summary of Maximum CO Concentrations Predicted for the Project at the Chassahowitzka NWA PSD Class I Area

Averaging Time	Highest Concentration [a] ($\mu g/m^3$)	Receptor UTM Location (km) East	Receptor UTM Location (km) North	Time Period [b] (Year/Day/Ending Time)
Annual	0.0020	338.5	3183.5	90123124
	0.0019	334.5	3183.6	92123124
	0.0018	338.5	3183.5	96123124
24-hour	0.0283	342.5	3175.2	90103024
	0.0356	342.5	3176.1	92042324
	0.0483	338.5	3183.5	96122724
8-hour	0.0581	342.5	3175.2	90103008
	0.0631	334.5	3183.6	92011916
	0.0839	339.3	3179.8	96122708
3-hour	0.116	339.9	3166.0	90103009
	0.141	334.5	3183.6	92011915
	0.238	342.5	3176.1	96122709
1-hour	0.142	337.7	3183.6	90032803
	0.164	338.5	3183.5	92052102
	0.260	342.5	3176.1	96122707

Note: UTM = Universal Transverse Mercator.

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

[b] YY = Year; MM = Month; DD = Day; HH = Hour ending.

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APPENDIX A

DETAILED EMISSION CALCULATIONS – PAST ACTUAL AND FUTURE POTENTIAL

Table A-1. Maximum Future Annual Emissions for Individual Fuels, No. 4 Combination Boiler, G-P Palatka

Regulated Pollutant	No. 6 Fuel Oil: Emission Factor	Ref.	Activity Factors [a]	Annual Emissions (TPY)	Wood Bark: Emission Factor	Ref.	Activity Factors [b]	Annual Emissions (TPY)	NCGs SOG DNCGs: Emission Factor	Ref.	Activity Factors	Annual Emissions (TPY)
Particulate (PM)	0.07 lb/MMBtu	1	795,000 MMBtu/yr	27.83	0.07 lb/MMBtu	1	4,042,127 MMBtu/yr	141.47	--	--	--	--
Particulate (PM_{10})	63 % of PM	2	--	17.53	74 % of PM	6	--	104.69	--	--	--	--
Sulfur dioxide	0.164 (S) lb/gal	3	5,300,000 gal/yr	1,021.31	0.025 lb/MMBtu	6	4,042,127 MMBtu/yr	50.53	785.0 tons/yr	8	--	785.0
Nitrogen oxides	0.2 lb/MMBtu	11	795,000 MMBtu/yr	79.50	0.24 lb/MMBtu	12	4,042,127 MMBtu/yr	485.06	0.9 lb/1000 gal condensate	9	48,000 gal/hr [c]	37.84
Carbon monoxide	5 lb/Mgal	4	5,300,000 gal/yr	13.25	0.60 lb/MMBtu	6	4,042,127 MMBtu/yr	1,212.64	--	--	--	--
VOC	0.28 lb/Mgal	4	5,300,000 gal/yr	0.74	0.017 lb/MMBtu	6	4,042,127 MMBtu/yr	34.36	--	--	--	--
Sulfuric acid mist	4.4 % of SO_2	5	--	44.94	4.4 % of SO_2	5	--	2.22	4.4 % of SO_2	5	--	34.54
Total reduced sulfur	--		--	--	--	--	--	--	5 ppmvd @ 10% O_2	10	135,400 dscfm	15.70
Lead	1.51E-03 lb/Mgal	4	5,300,000 gal/yr	4.00E-03	3.20E-04 lb/TWWF	7	449,125 tons/yr, wet	7.19E-02	--	--	--	--
Mercury	1.13E-04 lb/Mgal	4	5,300,000 gal/yr	2.99E-04	3.15E-05 lb/TWWF	6	449,125 tons/yr, wet	7.07E-03	--	--	--	--
Fluorides	3.73E-02 lb/Mgal	4	5,300,000 gal/yr	9.88E-02	--	--	--	--	--	--	--	--

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

[a] Based on proposed annual fuel oil limit of 5,300,000 gal/yr or 795,000 MMBtu/yr, based on 150,000 Btu/gal for fuel oil.

[b] Based on an annual capacity factor of 90% (461.43 MMBtu/hr and 449,125 TPY) of the 24-hour heat input limit of 512.7 MMBtu/hr in Permit No. 1070005-023-AV, or 499,320 TPY, wet, based on 4,500 Btu/lb and 8,760 hr/yr

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

References:
1. Proposed limit.
2. Based on AP-42 Section 1.3, Table 1.3-4, for utility boilers firing residual oil with an ESP (no factor available for industrial boilers with an ESP).
3. Based on current permit condition (Permit No. 1070005-023-AV). Does not include emissions due to NCG/SOG/DNCG burning. S = 2.35%.
4. Emission Factors based on AP-42 Section 1.3 Table 1.3-1, 1.3-3, 1.3-4 and 1.3-11 for metals (assuming uncontrolled for metals) (9/98)
5. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80)
6. Emission Factors based on AP-42 Section 1.6 Tables 1.6-1, 1.6-2, 1.6-3, and 1.6-4 (9/03). PM_{10} estimated to be 74% of PM based on the ratio of individuals emission factors for PM and PM_{10} from AP-42 Table 1.6-1 for wood-residue fired boilers with an ESP. Mercury factor based on conversion from 3.5E-6 lb/MMBtu to lb/ton wood/bark by multiplying by 9 MMBtu/ton.
7. Emission factor from EPA's FIRE system for wood/bark burning with multiple cyclone with fly ash reinjection control.
8. Based on maximum emissions due to NCGs/SOG/DNCGs combustion in the No. 4 Combination Boiler (264.9 TPY due to LVHC NCGs, 283.8 TPY due to SOGs, and 236.3 TPY due to HVLC DNCGs, assumes equal time for combustion of NCGs and SOGs, limited to 548.7 TPY SO_2 total).
9. Based on MACT I permit revision application (11/01)
10. Based on construction permit for Brown Stock Washer/O_2 Delig. System (July 2004)
11. Based on the use of low-NO_x burners and manufacturer's guarantee.
12. Based on no increase in current NO_x emissions due to bark/wood firing, on a lb/MMBtu basis.

Table A-2. Maximum Future Annual Emissions for Different Fuel Scenarios, No. 4 Combination Boiler, G-P Palatka

Regulated Pollutant	No. 6 Fuel Oil Only[a] Annual Emissions (TPY)	Wood/Bark Only[a] Annual Emissions (TPY)	Max No. 6 Fuel Oil w/ Remainder Wood/Bark[b] Annual Emissions (TPY)	NCGs/SOG/DNCGs Only[a] Annual Emissions (TPY)	Maximum Emissions for Any Fuel Combination with NCGs/SOG/DNCGs (TPY)	Maximum Emissions for Any Fuel Combination without NCGs/SOG/DNCGs (TPY)
Particulate (PM)	27.83	141.47	141.47	--	141.47	141.47
Particulate (PM_{10})	17.53	104.69	104.69	--	104.69	104.69
Sulfur dioxide	1,021.31	50.53	1,061.90	785	1,846.90	1,061.90
Nitrogen oxides	79.50	485.06	469.16	37.84	522.90	485.06
Carbon monoxide	13.25	1,212.64	987.39	--	1,212.64	1,212.64
VOC	0.74	34.36	28.34	--	34.36	34.36
Sulfuric acid mist	44.94	2.22	46.72	34.54	81.26	46.72
Total reduced sulfur	--	--	--	15.70	15.70	--
Lead	4.00E-03	7.19E-02	6.17E-02	--	7.19E-02	7.19E-02
Mercury	2.99E-04	7.07E-03	5.98E-03	--	7.07E-03	7.07E-03
Fluorides	9.88E-02	--	9.88E-02	--	9.88E-02	9.88E-02

Footnotes:

[a] Based on Table A-1.

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

Total Heat Input =	4,042,127	MMBtu/yr
Maximum Fuel Oil Usage =	5,300,000	gal/yr
Heat Input Due To Fuel Oil =	795,000	MMBtu/yr
Heat Input Due to Wood/Bark =	3,247,127	MMBtu/yr
Wood/Bark Usage =	360,792	tons/yr

Table A-3. Future Potential Hourly Emissions for Individual Fuels, No. 4 Combination Boiler, G-P Palatka

Regulated Pollutant	No. 6 Fuel Oil: Emission Factor	Ref	Activity Factors [a]	Hourly Emissions (lb/hr)	Wood Bark: Emission Factor	Ref.	Activity Factors [b]	Hourly Emissions (lb/hr)	NCGs/SOG/DNCGs: Emission Factor	Ref.	Activity Factors	Hourly Emissions (lb/hr)
Particulate (PM)	0.07 lb/MMBtu	1	418.6 MMBtu/hr	29.30	0.07 lb/MMBtu	1	512.7 MMBtu/hr	35.89	--	--	--	--
Particulate (PM_{10})	63 % of PM	2	--	18.46	74 % of PM	6	--	26.56	--	--	--	--
Sulfur Dioxide–24-Hour	0.164 (S) lb/gal	3	2,791 gal/hr	1,075.65	0.025 lb/MMBtu	6	512.7 MMBtu/hr	12.82	845.9 lb/hr	8	--	845.9
–3-Hour	0.164 (S) lb/gal	3	2,791 gal/hr	1,075.65	0.025 lb/MMBtu	6	512.7 MMBtu/hr	12.82	1,041.5 lb/hr	8	--	1,041.50
Nitrogen oxides	0.2 lb/MMBtu	11	418.6 MMBtu/hr	83.72	0.24 lb/MMBtu	12	512.7 MMBtu/hr	123.05	0.9 lb/1000 gal condensate	9	48,000 gal/hr [c]	43.20
Carbon monoxide	5 lb/Mgal	4	2.791 Mgal/hr	13.96	0.60 lb/MMBtu	6	512.7 MMBtu/hr	307.62	--	--	--	--
VOC	0.28 lb/Mgal	4	2.791 Mgal/hr	0.78	0.017 lb/MMBtu	6	512.7 MMBtu/hr	8.72	--	--	--	--
Sulfuric Acid Mist–24-Hour	4.4 % of SO_2	5	--	47.33	4.4 % of SO_2	5	--	0.56	4.4 % of SO_2	5	--	37.22
–3-Hour	4.4 % of SO_2	5	--	47.33	4.4 % of SO_2	5	--	0.56	4.4 % of SO_2	5	--	45.83
Total reduced sulfur	--		--	--	--	--	--	--	5 ppmvd @ 10% O_2	10	135,400 dscfm	3.60
Lead	1.51E-03 lb/Mgal	4	2.791 Mgal/hr	4.2E-03	3.20E-04 lb/TWWF	7	57.0 tons/hr, wet	1.82E-02	--	--	--	--
Mercury	1.13E-04 lb/Mgal	4	2.791 Mgal/hr	3.2E-04	3.15E-05 lb/TWWF	6	57.0 tons/hr, wet	1.80E-03	--	--	--	--
Beryllium	2.78E-05 lb/Mgal	4	2.791 Mgal/hr	7.8E-05	--	--	--	--	--	--	--	--
Fluorides	3.73E-02 lb/Mgal	4	2.791 Mgal/hr	1.0E-01	--	--	--	--	--	--	--	--

Notes:
TWWF - tons of wet wood residue fuel
NCGs= non-condensable gases; SOG= stripper off-gas, DNCGs= dilute NCGs.
Natural gas emissions not shown since it is a start up fuel only.
Footnotes
[a] Based on heat input limit of 418.6 MMBtu/hr in Permit No. 1070005-023-AV; or 2.791 Mgal/hr of fuel oil based on 150,000 Btu/gal.
[b] Based on heat input limit of 512.7 MMBtu/hr in Permit No. 1070005-023-AV; or 57.0 tons/hr, wet, based on 4,500 Btu/lb
[c] Design rate of 800 gpm for condensate stripper.
References:
1. Proposed limit.
2. Based on AP-42 Section 1.3, Table 1.3-4, for utility boilers firing residual oil with an ESP (no factor available for industrial boilers with an ESP)
3. Based on current permit condition (Permit No. 1070005-023-AV). Does not include emissions due to NCG/SOG/DNCG burning. S = 2.35%
4. Emission Factors based on AP-42 Section 1.3 Table 1.3-1, 1.3-3, 1.3-4 and 1.3-11 for metals (assuming uncontrolled for metals) (9/98)
5. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80)
6. Emission Factors based on AP-42 Section 1.6 Tables 1.6-1, 1.6-2, 1.6-3, and 1.6-4 (9/03). PM_{10} estimated to be 74% of PM based on the ratio of individuals emission factors for PM and PM_{10} from AP-42 Table 1.6-1 for wood-residue fired boilers with an ESP. Mercury factor based on conversion from 3.5E-6 lb/MMBtu to lb/ton wood bark by multiplying by 9 MMBtu/ton
7. Emission factor from EPA's FIRE system for wood/bark burning with multiple cyclone with fly ash reinjection control.
8. Based on maximum emissions due to NCGs/SOG/DNCGs combustion in the No. 4 Combination Boiler.
9. Based on MACT I permit revision application (11/01).
10. Based on construction permit for Brown Stock Washer/O_2 Delig. System (July 2004).
11. Based on the use of low-NO_x burners and manufacturer's guarantee
12. Based on no increase in current NO_x emissions due to bark/wood firing, on a lb/MMBtu basis.

Table A-4. Maximum Future Hourly Emissions for Different Fuel Burning Scenarios, No. 4 Combination Boiler, G-P Palatka

Regulated Pollutant	No. 6 Fuel Oil (lb/hr)	Wood/Bark (lb/hr)	NCGs/SOGs/ DNCGs (lb/hr)	Maximum Emissions For Any Fuel Combination: with NCGs/SOGs/DNCGs (lb/hr)	Maximum Emissions For Any Fuel Combination: without NCGs/SOGs/DNCGs (lb/hr)
Particulate (PM)--24-Hour	29.3	35.9	--	35.9	35.9
Particulate (PM_{10})--24-Hour	18.5	26.6	--	26.6	26.6
Sulfur dioxide--3-Hour	1,075.7	12.8	1,041.5	2,117.2	1,075.7
--24-Hour	1,075.7	12.8	845.9	1,921.5	1,075.7
Nitrogen oxides--24-Hour	83.7	123.0	43.2	166.2	123.0
Carbon monoxide--1-Hour	14.0	307.6	--	307.6	307.6
--8-Hour	14.0	307.6	--	307.6	307.6
VOC--1-Hour	0.78	8.72	--	8.7	8.7
Sulfuric acid mist--3-Hour	47.3	0.56	45.8	93.2	47.3
--24-Hour	47.3	0.56	37.2	84.5	47.3
Total reduced sulfur--1-Hour	--	--	3.60	3.6	--
Lead--1-Hour	4.21E-03	1.82E-02	--	1.82E-02	1.82E-02
Mercury--1-Hour	3.15E-04	1.80E-03	--	1.80E-03	1.80E-03
Beryllium--1-Hour	7.76E-05	--	--	7.76E-05	7.76E-05
Fluorides--1-Hour	1.04E-01	--	--	1.04E-01	1.04E-01

Reference: Hourly emissions from Table A-3.

Table A-5. Past Actual (2002-2003) 24-Hour Emissions for Highest Bark/Wood Burning Day (March 11, 2004) for the No. 4 Combination Boiler, GP Palatka Mill

Regulated Pollutant	Wood/Bark Emission Factor	Ref.	24-Hour Activity Factors [a]	24-Hr Average Emissions [b] (lb/hr)	No. 6 Fuel Oil Emission Factor	Ref.	24-Hour Activity Factors [c]	24-Hr Average Emissions (lb/hr)	Total Emissions (lb/hr)
Particulate (PM)	0.075 lb/MMBtu	1	47.1 tons bark/hr	31.81	0.033 lb/MMBtu	4	41,932 lbs/day	1.05 [d]	32.86
Particulate (PM_{10})	74 % of PM	2	--	23.54	63 % of PM	5	--	0.66	24.20
Carbon monoxide	5.4 lb/ton WWF	3	47.1 tons bark/hr	254.46	5 lb/1,000 gal	6	41,932 lbs/day	1.07 [e]	255.52
Nitrogen oxides	0.24 lb/MMBtu	7	423.9 MMBtu/hr	101.74	47 lb/1,000 gal	6	41,932 lbs/day	10.01 [e]	111.75
Sulfur dioxide	0.225 lb SO_2/ton WWF	3	47.1 tons bark/hr	10.6	0.164 (S) lb/gal	9	41,932 lbs/day	76.9 [e]	87.48
Sulfuric acid mist	4.4 % of SO_2	8	--	0.47	4.4 % of SO_2	8	--	3.38	3.85

Note: Highest 24-hour PM and CO emissions during 2002 through 2003 were determined to have occurred on March 11, 2004.

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

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

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

[d] Hourly emissions based on oil usage of 41,932 lbs/day, 0.033 lb PM/MMBtu, 8.2 lb/gal, and 150,000 Btu/gal.

[e] Hourly emissions emissions based on oil usage of 41,932 lbs/day, emission factor, and 8.2 lbs/gal.

References:

1. Based on average of last two years of stack test data when buring bark/wood (1/8/03 and 1/8/04).
2. PM_{10} estimated to be 74% of PM based on the ratio of individual emission factors for PM and PM_{10} from AP-42 Table 1.6-1 for wood-residue fired boilers with an ESP.
3. Emission factor based on AP-42 Section 1.6 Table 1.6-1 (3/02). Emission factor converted from lb/MMBtu to lb/ton of wood/bark by multiplying by 9 MMBtu/ton (CO = 0.60 lb/MMBtu).
4. Emission factor based on last two years of stack test data when burning fuel oil only (1/8/03 and 1/8/04).
5. Based on AP-42 Section 1.3, Table 1.3-4, for utility boilers firing residual oil with an ESP (no factor available for industrial boilers with an ESP).
6. Emission factor based on AP-42 Section 1.3 Table 1.3-1 (9/98).
7. Based on estimated current NO_x emissions due to bark/wood firing, on a lb/MMBtu basis.
8. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).
9. Emission Factors based on AP-42 Section 1.3 Table 1.3-1. S = 2.2 % (average actual sulfur content for 2002 and 2003).

Table A-6. Past Actual (2002-2003) 24-Hour Emissions for Highest Fuel Oil Burning Day (March 14, 2003) for the No. 4 Combination Boiler, GP Palatka Mill

Regulated Pollutant	Wood/Bark Emission Factor	Ref.	24-Hour Activity Factors [a]	24-Hr Average Emissions [e] (lb/hr)	No. 6 Fuel Oil Emission Factor	Ref.	24-Hour Activity Factors [b]	24-Hr Average Emissions [e] (lb/hr)	Total 24-Hour Emissions (lb/hr)
Particulate (PM)	0.075 lb/MMBtu	1	73.95 tons/day	2.08	0.033 lb/MMBtu	7	18,888 lbs oil/hr	11.40 [d]	13.48
Particulate (PM_{10})	74 % of PM	2	--	1.54	63 % of PM	8	--	7.18	8.72
Carbon monoxide	5.4 lb/ton WWF	3	73.95 tons/day	16.64	5 lb/1,000 gal	9	18,888 lbs oil/hr	11.52	28.16
Nitrogen oxides	0.24 lb/MMBtu	4	27.73 MMBtu/hr	6.66	47 lb/1000 gal	9	18,888 lbs oil/hr	108.26 [c]	114.91
Sulfur dioxide	0.225 lb SO_2/ton WWF	5	73.95 tons/day	0.7	0.164 (S) lb/gal	9	18,888 lbs oil/hr	831.1 [c]	831.75
Sulfuric acid mist	4.4 % of SO_2	6	--	0.03	4.4 % of SO_2	6	--	36.57	36.60

Note: Highest 24-hour SO_2 emissions during 2002 through 2003 were determined to have occurred on March 14, 2003.

[a] Bark usage rate of 73.95 tons/day based on 3/14/03 actual operation, and 4,500 Btu/lb.
[b] Based on fuel oil usage of 453,301 lbs/day on 3/14/03 actual operation.
[c] Based on density of 8.2 lbs/gal and sulfur content of 2.2%.
[d] Based on density of 8.2 lbs/gal and heat content of 150,000 Btu/gal.
[e] Hourly emissions based on the daily emission rate and 24 hours/day.

References:
1. Based on average of last two years of stack test data when buring bark/wood (1/8/03 and 1/8/04).
2. PM_{10} estimated to be 74% of PM based on the ratio of individual emission factors for PM and PM_{10} from AP-42 Table 1.6-1 for wood-residue fired boilers with an ESP.
3. Emission factor based on AP-42 Section 1.6 Table 1.6-1 (3/02). Emission factor converted from lb/MMBtu to lb/ton of wood/bark by multiplying by 9 MMBtu/ton (CO = 0.60 lb/MMBtu).
4. Based on current estimated NO_x emissions due to bark/wood firing, on a lb/MMBtu basis.
5. Emission factor based on AP-42 Section 1.6 Table 1.6-1 (3/02). Emission factor converted from lb/MMBtu to lb/ton of wood/bark by multiplying by 9 MMBtu/ton (SO_2 = 0.025 lb/MMBtu).
6. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).
7. Emission factor based on last two years of stack test data when burning fuel oil only (1/8/03 and 1/8/04).
8. Based on AP-42 Section 1.3, Table 1.3-4, for utility boilers firing residual oil with an ESP (no factor available for industrial boilers with an ESP).
9. Emission Factors based on AP-42 Section 1.3 Table 1.3-1. S = 2.2 % (average actual sulfur content for 2002 and 2003).

Table A-7. Past Actual (2002-2003) 24-Hour Emissions for Highest Fuel Oil Burning Day (November 4, 2002) for the No. 4 Power Boiler, GP Palatka Mill

Regulated Pollutant	No. 6 Fuel Oil Emission Factor	Ref.	24-Hour Activity Factors	24-Hr Average Emissions (lb/hr)
Sulfur dioxide	0.157 (S) lb/gal	1	832 gal oil/hr [a]	287.3 [b]
Sulfuric acid mist	4.4 % of SO_2	2	--	12.64
Nitrogen oxides	47 lb/1000 gal	1	832 gal oil/hr [a]	39.09
Particulate (PM)	0.033 lb/MMBtu	4	832 gal oil/hr [a]	4.12
Particulate (PM_{10})	63 % of PM	3	--	2.59
Carbon monoxide	5 lb/1,000 gal	1	832 gal oil/hr [a]	0.51

Note: Highest 24-hour oil usage during 2002 through 2003 were determined to have occurred on November 14, 2002.

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

[b] Based on sulfur content of 2.2%.

References:

1. Emission Factors based on AP-42 Section 1.3 Table 1.3-1. S = 2.2 % (average actual sulfur content for 2002 and 2003).
2. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).
3. Based on AP-42 Section 1.3, Table 1.3-4, for utility boilers firing residual oil with an ESP (no factor available for industrial boilers with an ESP).
4. Based on last 2 years of stack test data when burning fuel oil only (1/8/03 and 1/8/04).

APPENDIX B

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

B.1 INTRODUCTION

As part of the new source review requirements under Prevention of Significant Deterioration (PSD) regulations, new or modified sources are required to address air quality impacts at PSD Class I areas that are within 200 km of a project. As a result, the air quality impacts due to the potential emissions of the proposed project at the G-P Palatka Mill are required to be addressed at the PSD Class I areas of the Okefenokee National Wildlife Area (NWA), Wolf Island NWA, and Chassahowitzka NWA as part of the modeling report submitted to the Florida Department of Environmental Protection (FDEP). The Okefenokee NWA is located 108 kilometers (km) north of the G-P Palatka Mill. The Wolf Island NWA is located 186 km north of the G-P Palatka Mill. The Chassahowitzka NWA is located 137 km southwest of the G-P Palatka Mill. For this analysis, air quality impacts were provided for each of the PSD Class I areas.

The evaluation of air quality impacts are not only concerned with determining compliance with PSD Class I increments but also assessing a source's impact on Air Quality Related Values (AQRVs), such as regional haze. Further, compliance with PSD Class I increments can be evaluated by determining if the source's impacts are less than the proposed U.S. Environmental Protection Agency (EPA) Class I significant impact levels. The significant impact levels are threshold levels that are used to determine the type of air impact analyses needed for the facility. If the new or modified source's impacts are predicted to be less than significant, then the source's impacts are assumed not to have a significant adverse affect on air quality and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance with Class I increments.

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

- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report.

- *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report*, USFS, NPS, USFWS (December, 2000), referred to as the FLAG document.

For a project located within 50 km of a PSD Class I area, a short-range transport air dispersion model should be used to address air quality impacts. For a project located beyond 50 km of a PSD Class I area, a long-range air dispersion model should be used to address air quality impacts.

B.2 GENERAL AIR MODELING APPROACH

The Industrial Source Complex Short-Term (ISCST) is recommended by the regulatory agencies to address air quality impacts for projects located within 50 km of a PSD Class I area. At distances beyond 50 km, the ISCST3 model is considered to over-predict air quality impacts because it is a steady-state model. At those distances, the California Puff (CALPUFF) model is recommended for use. The FLM have requested that air quality impacts for a source located more than 50 km from a Class I area be predicted using the CALPUFF model.

The following sections present the methods and assumptions used to assess the impacts of the proposed project. The analysis is consistent with a "refined analysis" since it was performed using the detailed weather data from multiple surface and upper air stations as well as the MM4/MM5 prognostic with fields.

B.3 MODEL SELECTION AND SETTINGS

The California Puff (CALPUFF, version 5.711a) air modeling system was used to model to assess the proposed project's impacts at the PSD Class I area for comparison to the PSD Class I significant impact levels. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALPUFF meteorological and geophysical data preprocessor (CALMET, Version 5.53a), a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters. CALMET was designed to process raw meteorological, terrain and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET was input to CALPUFF to assess the pollutant specific impact. Both CALMET and CALPUFF were used in a manner that is recommended by the IWAQM Phase 2 and FLAG reports.

B.3.1 CALPUFF MODEL APPROACHES AND SETTINGS

The methods and assumptions used in the CALPUFF model were based on the latest recommendations for a refined analysis as presented in the IWAQM Phase 2 Summary Report and the FLAG documents. The IWAQM has recommended approaches for performing a Phase 2 refined modeling analyses that are presented in Table B-1. These approaches involve use of meteorological data, selection of receptors and dispersion conditions, and processing of model output.

The specific settings used in the CALPUFF model are presented in Table B-2.

B.3.2 EMISSION INVENTORY AND BUILDING WAKE EFFECTS

The CALPUFF model included the facility's emission, stack, and operating data as well as building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the Building Profile Input Program modified to process additional direction-specific building information (BPIP), Version 95039, and were included in the CALPUFF model input. The modeling presents a listing of the facility's emissions and structures included in the analysis.

B.4 RECEPTOR LOCATIONS

The proposed project's maximum pollutant concentrations and visibility impairment on regional haze were evaluated at the Okefenokee NWA using 500 receptors, at Wolf Island NWA using 30 receptors; and on the boundary of the Chassahowitzka NWA using 58 receptors.

B.5 METEOROLOGICAL DATA

B.5.1 REFINED ANALYSIS

CALMET was used to develop the grid pattern for the parameter fields required for the refined modeling analyses for the Okefenokee, Wolf Island, and Chassahowitzka NWA. A wind field domain was developed that includes all PSD Class I areas that were evaluated in this analysis. The following sections discuss the specific data used and processed in the CALMET model.

B.5.2 CALMET SETTINGS

The CALMET settings contained in Table B-3 were used for the refined modeling analysis. All input data files needed for CALMET were developed by Golder, with the exception of the upper air and sea surface meteorological data files, which were developed by the FDEP.

B.5.3 MODELING DOMAIN

A rectangular modeling domain extending 448 km in the east-west (x) direction and 684 km in the north-south (y) direction was used for the refined modeling analysis. The southwest corner of the domain is the origin and is located at 26.25 degrees north latitude and 85.0 degrees west longitude (east and north UTM coordinates of 77 and 2966.0 km, respectively, zone 17 equivalent). This location is in the Gulf of Mexico approximately 250 km west of Naples, Florida. For the processing of meteorological and geophysical data, the domain contains 112 grid cells in the x-direction and 171 grid cells in the y-direction. The domain grid resolution is 4 km. The air modeling analysis was developed in the UTM coordinate system, Zone 17.

B.5.4 MESOSCALE MODEL – GENERATION 4 AND 5 (MM4/MM5) DATA

Pennsylvania State University in conjunction with the NCAR Assessment Laboratory developed the MM4 and MM5 data set, a prognostic wind field or "guess" field, for the United States. The hourly meteorological variables used to create this data set (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and are available for 1990, 1992, and 1996. The analysis used the MM4 and MM5 data to initialize the CALMET wind field. The MM4 and MM5 data available for 1990 and 1992, respectively, have a horizontal spacing of 80 km and are used to simulate atmospheric variables within the modeling domain. The MM5 data are also available for 1996 and have a horizontal spacing of 36 km.

The 1990 MM4 subset domain and 1992 MM5 subset domain consist of a 11 x 14- cell rectangle, with 80 km grid resolution, extending from the MM4/5 grid points (46,8) to (56,21). These data were processed to create a MM4/5.DAT file, for input to the CALMET model. The 1996 MM5 subset domain consisted of a 21 x 25- cell rectangle, with 36 km grid resolution, extending from the MM5 grid points (117,23) to (137,47).

The MM4 and MM5 data used in the CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables were processed into the appropriate format and introduced into the CALMET model through the additional data files obtained from the following sources.

B.5.5 SURFACE DATA STATIONS AND PROCESSING

The surface station data processed for the CALPUFF analyses consisted of data from up to sixteen NWS stations or Federal Aviation Administration (FAA) Flight Service stations for:

- Tampa, Jacksonville, Daytona Beach, Tallahassee, Vero Beach, Fort Myers, Orlando, Pensacola and Gainesville in Florida;
- Columbus, Macon, Savannah, Augusta, Athens, and Atlanta in Georgia; and
- Charleston in South Carolina.

A summary of the surface station information and locations are presented in Table B-4. The surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions. The surface station data were processed into a SURF.DAT file format for CALMET input.

Because the modeling domain extends over water, up to 10 sea surface stations were incorporated in the analysis for each of the years evaluated. Data were obtained from available C-Man stations and NOAA buoys. These data were processed into an over-water surface station format (i.e., SEA*.DAT) for input to CALMET. The over-water station data include wind direction, wind speed and air temperature.

B.5.6 UPPER AIR DATA STATIONS AND PROCESSING

Upper air data from the following NWS stations, based on the availability of the upper air data, were used in the modeling analysis:

- Waycross, Georgia (1990, 1992);
- Athens, Georgia (1990, 1992);
- Charleston, South Carolina (1990, 1992, 1996);
- Cape Canaveral (1996)
- Miami (1996)
- Apalachicola, Florida (1990);
- Ruskin, Florida (1990, 1992, 1996);
- Tallahassee, Florida (1992, 1996);

- West Palm Beach (1990, 1992)
- Jacksonville, Florida (1996); and
- Peachtree City, Georgia (1996).

B.5.7 PRECIPITATION DATA STATIONS AND PROCESSING

Precipitation data were processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation-recording stations located within the latitude and longitudinal limits of the modeling domain. Data for up to 82 stations in Alabama, Georgia and Florida were obtained in NCDC TD-3240 variable format and converted into a fixed-length format. The utility programs PXTRACT and PMERGE were then used to process the data into the format for the PRECIP.DAT file that is used by CALMET.

B.5.8 GEOPHYSICAL DATA PROCESSING

Terrain elevations for each grid cell of the modeling domain were obtained from 1-degree Digital Elevation Model (DEM) files obtained from the U.S. Geographical Survey (USGS) Internet website. The DEM data was extracted for the modeling domain grid using the utility program TERREL. Land-use data were also extracted from 1-degree USGS files and processed using utility programs CTGCOMP and CTGPROC. Both the terrain and land use files were combined into a GEO.DAT file for input to CALMET with the MAKEGEO utility program.

Table B-1. Refined Modeling Analyses Recommendations [a]

Model Input/Output	Description
Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; obtain regulatory concurrence on coverage.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition. 3. Define background values for ozone and ammonia for area.
Processing	1. For PSD increments: use highest, second highest 3-hour and 24-hour average SO_2 concentrations; highest, second highest 24-hour average PM_{10} concentrations; and highest annual average SO_2, PM_{10} and NO_x concentrations. 2. For haze: on a 24-hour basis, compute the source extinction from the maximum increase in emissions of SO_2, sulfuric acid mist, NO_x and PM_{10}; compute the daily relative humidity factor [f(RH)], provided from an external disk file; and compute the maximum percent change in extinction using the FLM supplied background extinction data in the FLAG document. 3. For significant impact analysis: use highest annual and highest short-term average concentrations for SO_2, PM_{10} and NO_x.

[a] IWAQM Phase II report (December, 1998) and FLAG document (December, 2000)

Table B-2. CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10}
Chemical Transformation	MESOPUFF II scheme, hourly ozone data
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG /MP coefficients, rural mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration file including output species for SO_4, NO_3, PM_{10}, SO_2, and NO_x; process for visibility change using Method 2 and FLAG background extinctions
Model Processing	For haze: highest predicted 24-hour extinction change (%) for the year For deposition: annual average deposition rate For significant impact analysis: highest predicted annual and highest short-term averaging time concentrations for SO_2, NO_x, and PM_{10}.
Maximum Relative Humidity	95%
Background Values	Ozone: 50 ppb; Ammonia: 1 ppb

Table B-3. CALMET Settings

Parameter	Setting
Horizontal Grid Dimensions	448 by 684 km, 4 km grid resolution
Vertical Grid	10 layers
Weather Station Data Inputs	Surface, upper air, and precipitation stations
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	1990 MM4 and 1992 data, 80 km resolution; 1996 MM5 data, 36 km resolution; used for wind field initialization
Output	Binary hourly grid pattern for meteorological data file for CALPUFF input

Table B-4. Surface and Upper Air Stations Used in the North Central Florida – South Georgia Domain (Page 1 of 2)

			UTM Coordinates			
Station Name	Station Symbol	WBAN Number	Easting (km)	Northing (km)	UTM Zone	Anemometer Height (m)
Surface Stations						
Tampa, FL	TPA	12842	349.195	3094.289	17	10
Jacksonville, FL	JAX	13889	432.809	3374.192	17	10
Daytona Beach, FL	DAB	12834	495.118	3228.056	17	10
Tallahassee, FL	TLH	93805	176.408[a]	3365.835	16	10
Fort Myers, FL	FMY	12835	413.644	2940.405	17	10
Orlando, FL	MCO	12815	468.942	3146.889	17	10
Pensacola, FL	PNS	13899	-95.740	3386.714	16	10
Vero Beach, FL	VRB	12843	557.487	3058.363	17	10
Columbus, GA	CSG	93842	128.871[a]	3604.422	16	10
Charleston, SC	CHS	13880	590.422	3640.405	17	10
Macon, GA	MCN	3813	251.562	3620.929	17	10
Savannah, GA	SAV	3822	481.120	3554.985	17	10
Gainesville, FL	GNV	12816	377.390	3284.126	17	10
Augusta, GA	AGS	3820	410.024	3692.184	17	10
Athens, GA	AHN	13873	285.867	3758.824	17	10
Atlanta, GA	ATL	13874	181.588[a]	3728.434	16	10
Sea Surface Stations						
Venice, FL	VENF1	-	356.24	2995.05	17	-
Cape Canaveral, FL	41009	-	380.25	3152.87	17	-
Tampa West, FL	42036	-	156.41	3158.73	16	-
Cedar Key, FL	CDRF1	-	302.52	3225.20	17	-
Cape San Blas, FL	CSBF1	-	77.89	3290.18	16	-
Folly Island, SC	FBIS1	-	604.09	3616.38	17	-
Keaton Beach, FL	KTNF1	-	249.71	3301.66	17	-
Lake Worth, FL	LKWF1	-	596.57	2943.61	17	-
Savannah, GA	SVLS1	-	530.24	3534.94	17	-

Table B-4. Surface and Upper Air Stations Used in the North Central Florida – South Georgia Domain (Page 2 of 2)

Station Name	Station Symbol	WBAN Number	UTM Coordinates Easting (km)	UTM Coordinates Northing (km)	UTM Zone	Anemometer Height (m)
St. Augustine, FL	SAUF1	-	474.89	3303.30	17	-
Upper Air Stations						
Ruskin, FL	TPA	12842	361.961	3064.616	17	NA
Waycross, GA	AYS	13861	366.674	3457.945	17	NA
Athens, GA	AHN	13873	285.866	3758.824	17	NA
Charleston, SC	CHS	13880	590.421	3640.405	17	NA
Cape Canaveral	XMR	12868	544.048	3150.459	17	NA
Miami –FIU	MFL	92803	562.181	2847.983	17	NA
Apalachicola, FL	AQQ	12832	109.807[a]	3295.816	16	NA
Tallahassee, FL	TLH	93805	176.407[2]	3365.835	16	NA
Jacksonville, FL	JAX	13889	432.808	3374.192	17	NA
Peachtree, GA	FFC	53819	155.637[2]	3696.207	16	NA

[a] Equivalent coordinate for Zone 17.

APPENDIX C

VENDOR INFORMATION – OVERFIRE AIR SYSTEMS

JANSEN

JANSEN OFA SYSTEM BENEFITS

Excellent Combustion Characteristics

- Ensures CO Will Meet Goals
- Eliminates Channeling
- Maximizes Waste Wood Burning
- Eliminates Delayed Combustion/Puffing
- Reduces Undergrate Air/ Excess Air Needed
- Minimizes Carryover
- Minimizes Need for Fossil Fuels

JANSEN
Combustion and Boiler Technologies, Inc.

JANSEN OFA SYSTEM BENEFITS (cont.)

- Simplicity of Operation/Maintenance
- Ease of Installation
  - Supply Ducting - Simple, Straight Forward
  - Side Walls Provide Easy Access for Furnace Tube Work
  - Minimum Tube Welds Required

JANSEN
Combustion and Boiler Technologies, Inc.

TOLKO INDUSTRIES NO. 2 BARK BOILER

- Foster Wheeler - Water Cooled Grate
  - Rear Wall OFA Ports
  - Abandoned Concentric OFA System
- The "Before" OFA Upgrade Symptoms
  - Delayed Combustion/Puffing/High Superheater Temperature Excursions
  - Low Wood Burning Rates
  - Auxiliary Fuel Required To Support Combustion

JANSEN
Combustion and Boiler Technologies, Inc.

TOLKO INDUSTRIES (cont.)

JANSEN Upgrade

- Six OFA Nozzles per Side Wall
- Four Nozzles Above Fuel Feeders
- Two Nozzles Above Lower Grate
- Used Existing FD Fan - No Booster Fan Required

JANSEN
Combustion and Boiler Technologies, Inc.

TOLKO INDUSTRIES (cont.)

The "After" Conditions

- Puffing Virtually Eliminated
- Increased Wood Firing Rate by >50%
- Follows Load on Wood Only
- Eliminated Need for Auxiliary Fuel

Payback Period <6 Months

JANSEN
Combustion and Boiler Technologies, Inc.

MEAD CHILLICOTHE NO. 6 BARK BOILER

Converted Recovery Boiler - Traveling Grate

- Small Front & Rear Wall OFA Ports

"Before"

- DNCGs to Undergrate and Old OFA
- Leakage Into Building
- CO Levels 2,000 ppm

JANSEN
Combustion and Boiler Technologies, Inc.

MEAD CHILLICOTHE (cont.)

JANSEN Upgrade

- Four OFA Nozzles per Side Wall
- Used Existing FD Fan
- DNCGs to JANSEN OFA Only

"After" Conditions

- No Leakage of DNCGs
- CO Levels 250 ppm/ HC's 2 ppm

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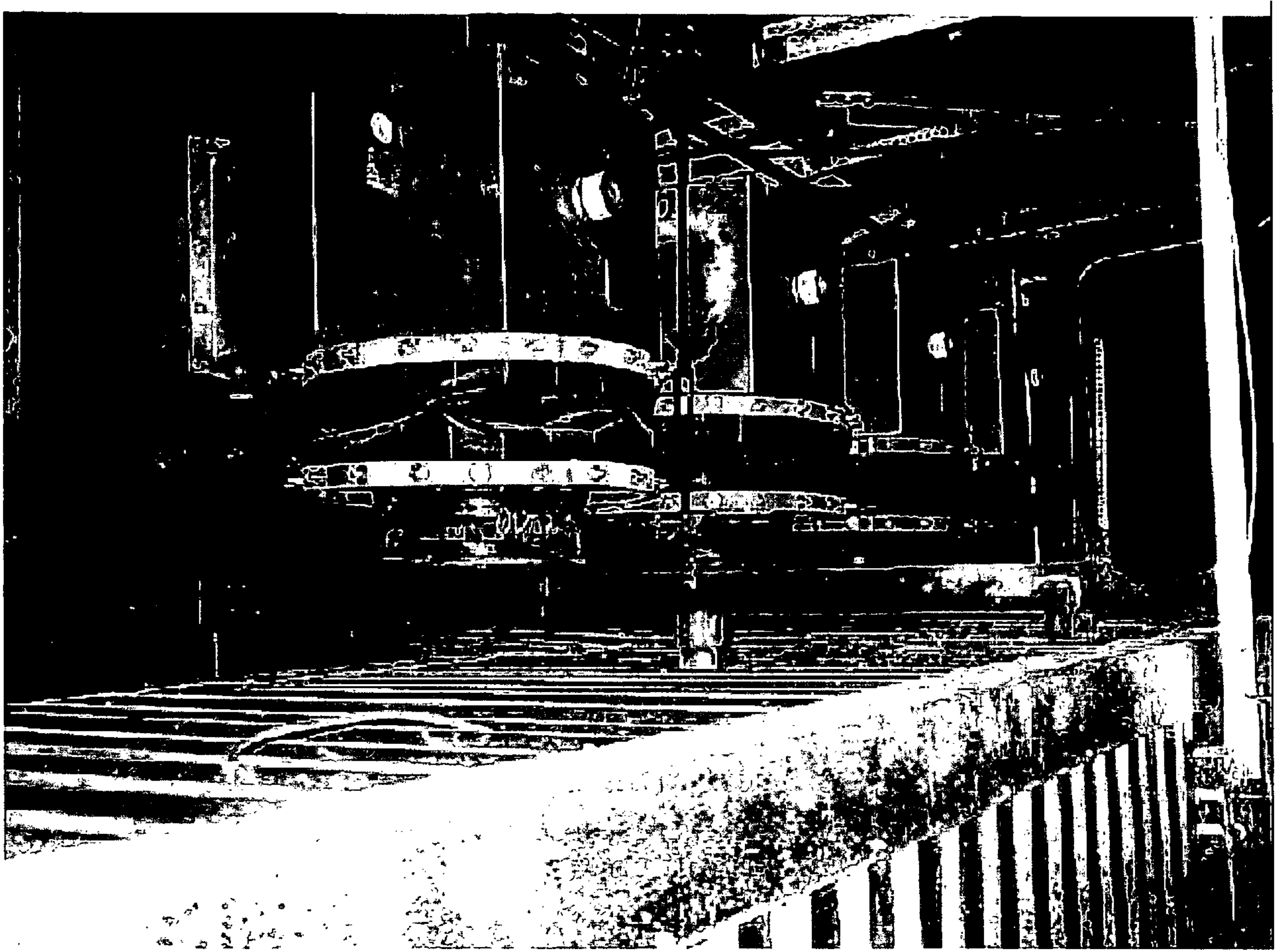

MEAD PHENIX CITY NO. 2 BARK BOILER

- CE VU-40 - Traveling Grate
  - Side Wall Cyclonic OFA System
  - Burns Bark and Sludge
- "Before" OFA Upgrade Symptoms
  - Difficulty Meeting CO Emissions without Co-firing with Natural Gas
  - CO Levels 1,000 to 2,000 ppm
  - Moderate to High Carryover

JANSEN Combustion and Boiler Technologies, Inc.

MEAD PHENIX CITY (cont.)

- JANSEN Upgrade
  - Five OFA Nozzles per Side Wall
  - Used Existing FD Fan
- "After" Conditions
  - Passed Stack Testing without Auxiliary Fuel Burning
  - CO Levels During Testing < 250 ppm
  - Reduced Carryover

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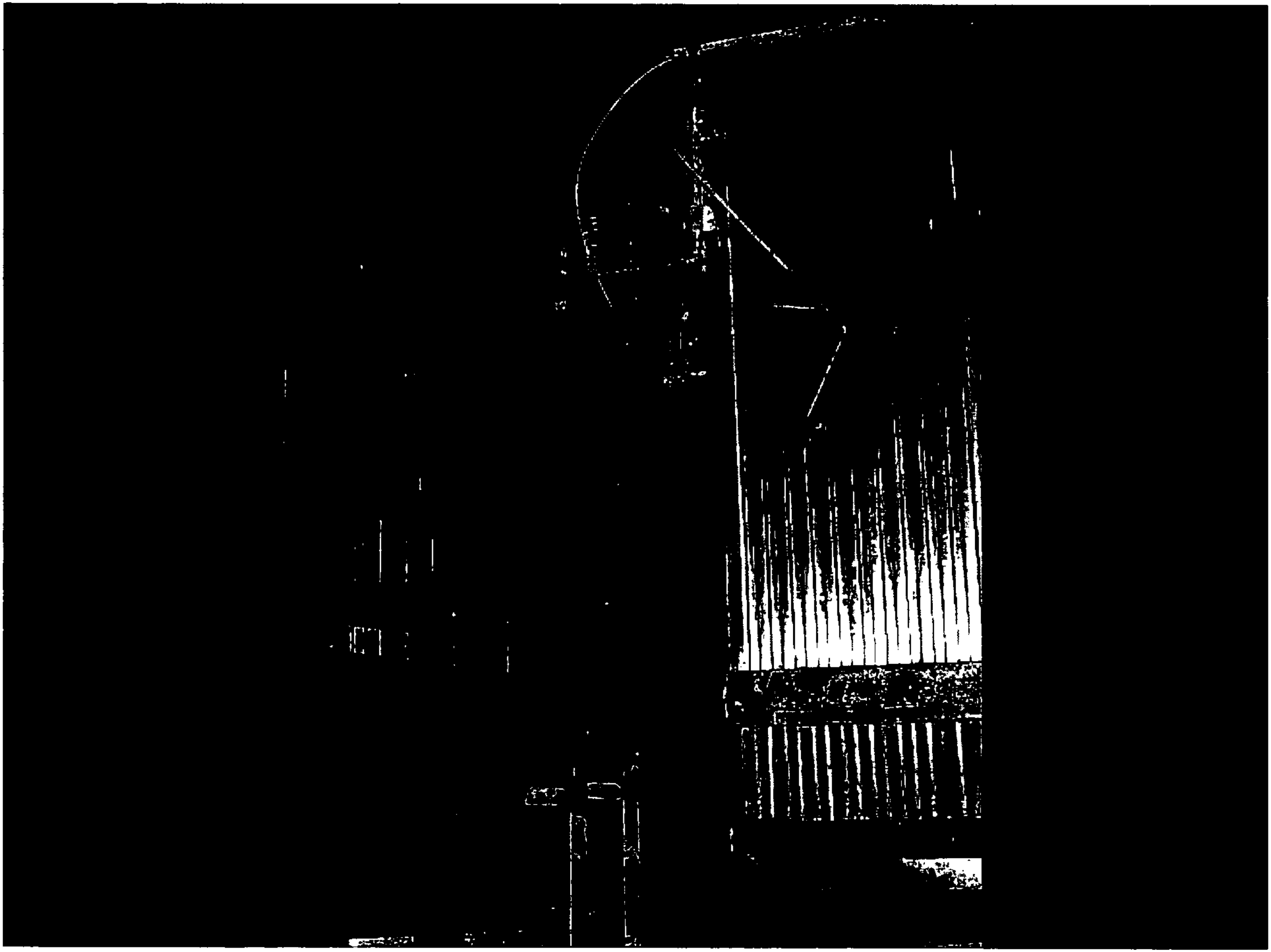

IP – JAY, MAINE WFI BOILER

B&W - Traveling Grate

- Front & Rear Wall Multi-level OFA System
- Burns Bark and Sludge

"Before" OFA Upgrade Symptoms

- Difficulty Meeting Particulate Emissions
- Required to Burn 4 gpm Oil by State EPA
- Excessive Carryover Out of Furnace
- 41 lb/hr Particulate at <250,000 lb/hr Steam on Bark

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Technologies, Inc.

IP - JAY (cont.)

JANSEN Upgrade

- Four OFA Nozzles per Side Wall
- Used Existing FD Fan
- Fast Track; Phased Installation

"After" Conditions

- Passed Stack Testing with Target Oil Firing of 1 gpm
- 36 lb/hr Particulate at 265,000 lb/hr Steam on Bark

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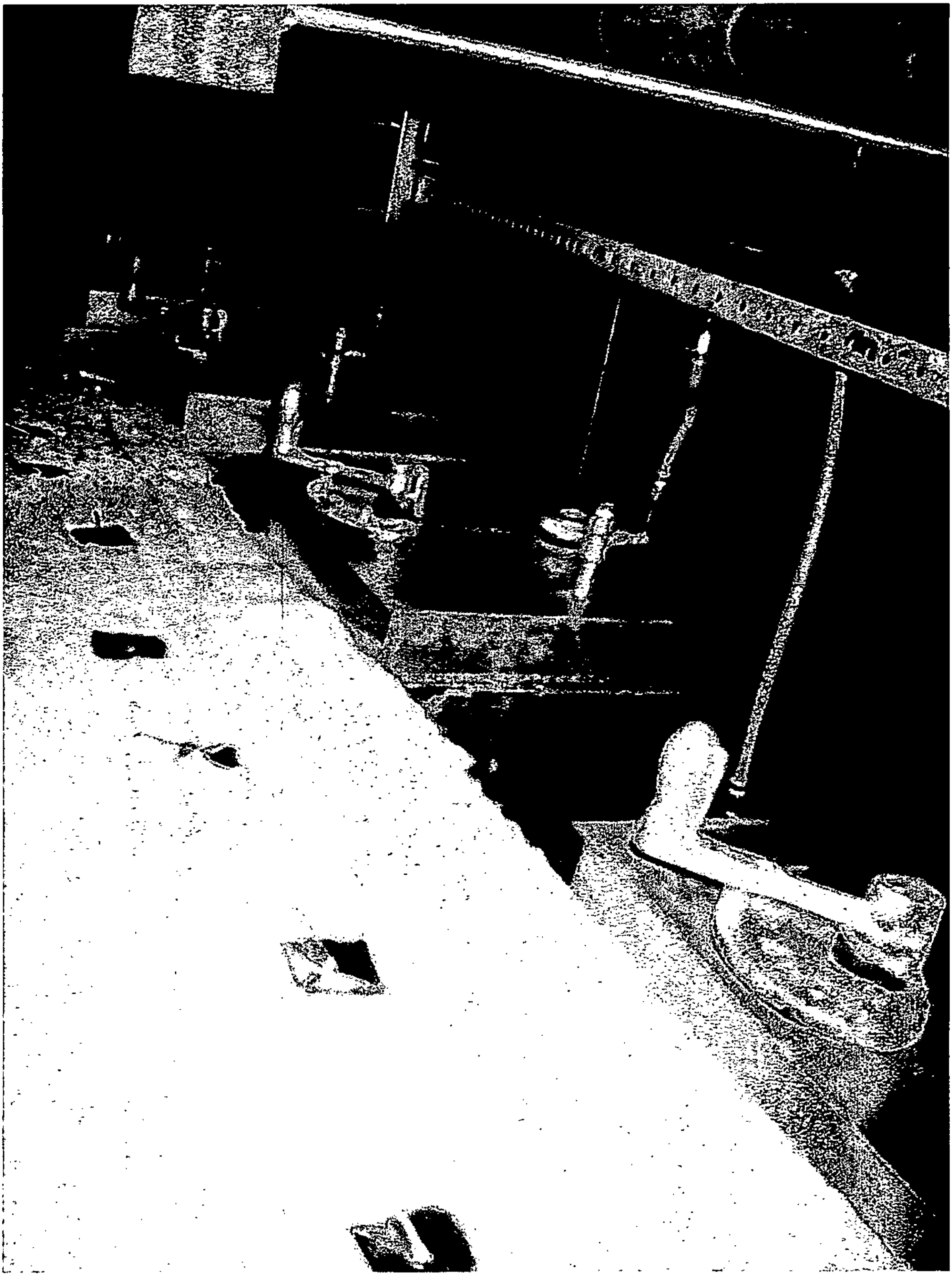
Combustion and Boiler Technologies, Inc.



IP – TEXARKANA, TX NO. 2 POWER BOILER

CE VU-40 Traveling Grate
- 775,000 lb/hr MCR
- Side Wall Cyclonic OFA System
- Bark and Natural Gas

"Before" OFA Upgrade Symptoms
- Unable to Meet Bark Burning Goals
- High Carryover of Ash and Char

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IP – TEXARKANA (cont.)

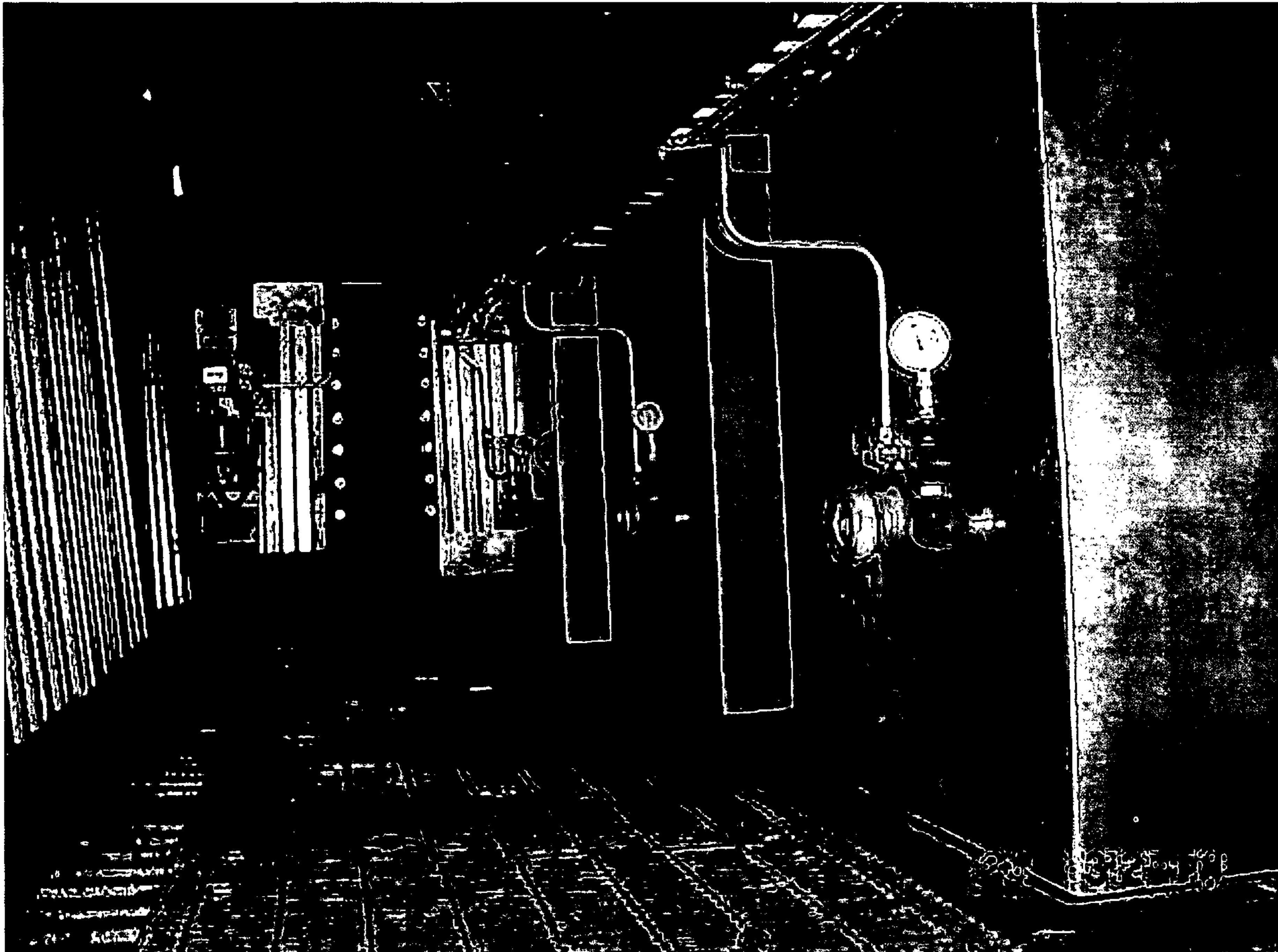
JANSEN Upgrade

- Four OFA Nozzles per Side Wall
- Used Existing FD Fan

"After" Conditions

- Increased Reliable Bark Firing up to 20 t/hr
- Reduced NO_x Emissions by 6%
- Reduced Carryover
- Reduced PM Emissions up to 58%
- Reduced Grate Temperatures by > 75° F

JANSEN Combustion and Boiler Technologies, Inc.



IP – BASTROP, LA
NO. 3 POWER BOILER

Foster Wheeler – Traveling Grate

- Front & Rear Wall, Small OFA Ports
- Burns Bark, TDF, Sludge, PC or Nat. Gas

"Before" OFA Upgrade

- Unable to Meet Target Waste Fuel Burning
- High Levels of Carbon in Fly Ash

JANSEN
Combustion and Boiler Technologies, Inc.

IP – BASTROP (cont.)

JANSEN Upgrade

– Four OFA Nozzles per Side Wall
– Used Existing FD Fan

"After" Conditions

– Waste Fuel Burning Increased by 17%
– Reduced Carbon in Fly Ash by >50%
– Follows Steam Demand on Waste Fuels
– Minimized Need for Auxiliary Fuels

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Technologies, Inc.

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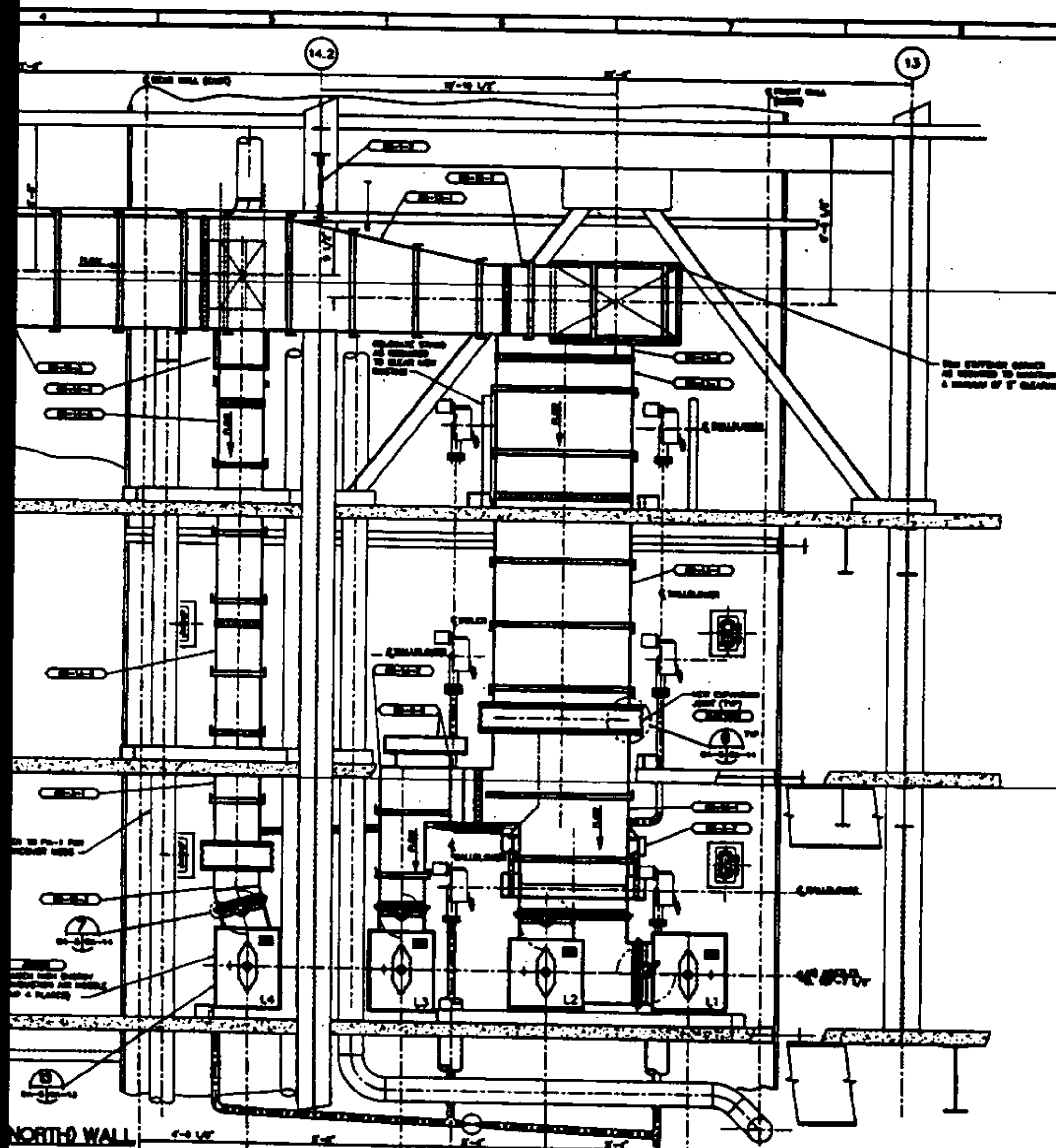

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NOTES:

JANSEN
Combustion and Boiler Technologies, Inc.
Customized Engineered Solutions

APPROVED FOR CONSTRUCTION

INTERNATIONAL PAPER
BASTROP, LOUISIANA

No.3 POWER BOILER UPGRADE
OVERFIRE AIR SYSTEM
LEFT (NORTH) SIDEWALL ELEVATION

OA-5

SUMMARY

- Excellent Experience - Fifteen Power Boiler Upgrades
- Four Systems Designed to Burn HVCL NCG
- Side Wall Installation
  - Optimum Nozzle Placement
  - Ease of Installation

JANSEN
Combustion and Boiler
Technologies, Inc.

SUMMARY (cont.)

- CFD Modeling
  - Provides Confidence in the Outcome
  - Allows Optimization of Design
- Maximizes Waste Wood Burning
- Highly Turbulent Mixing OFA
- JANSEN Patented Nozzles
- Generally No Fan Changes Required

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Tappi Engineering Conference Paper 2000

Elements of a Successful Bark Boiler Upgrade

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ELEMENTS OF A SUCCESSFUL BARK BOILER UPGRADE

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ABSTRACT

Mead Coated Board Inc. operates an early 1980s vintage Combustion Engineering Type VU-40 Bark Boiler at its Mahrt mill near Phenix City, Alabama. The mill had an interest in improving the combustion efficiency of the unit by reducing the reliance on burning natural gas for CO control and reducing unburned carbon in the fly ash.

The project was initiated by an engineering site visit and evaluation. The boiler had a history of unstable burning of hog fuel and primary clarifier sludge on the grate, which led to elevated levels of combustible gases in the upper furnace. It was decided to:

1. Install a new OFA system,
2. Install new air flow measurement devices,
3. Improve flue gas O_2 measurement for air trim.

In addition, as part of the project, the mill upgraded the boiler control system strategy to improve control of combustion air, fuel, furnace draft, and steam generation.

Different OFA arrangements were evaluated via CFD modeling. The results showed the limitations of the original tangential system, which precluded mixing of air and combustible gases in the middle of the boiler. Previous evaluations had shown that many, small OFA nozzles on the front and rear walls could not provide the required mixing of air above the grate. Installation of large OFA nozzles on the front and rear walls was given cursory consideration, but was rejected due to all of the interferences (fuel chutes, fuel distributor air, ash reinjection system, downcomers, etc.).

The side walls were virtually free of interferences and the CFD model confirmed that placement of the nozzles on the side walls gave better combustion than on the front and rear walls. The CFD model was also used to optimize the number, size, and location of OFA ports.

Installation of the new OFA system was completed in September 1999. Subsequent testing of the boiler showed that it could reliably meet the state emission levels for CO (0.4 lb/MM Btu) and NO_x (0.3 lb/MM Btu) while running at full load on a mixture of hog fuel and sludge.

INTRODUCTION

Mead Coated Board Inc. operates an early 1980s vintage Combustion Engineering Type VU-40 Bark Boiler at its Mahrt mill near Phenix City, Alabama. The boiler was designed to produce 300,000 lb/hr of steam at a temperature of 825°F and a pressure of 890 psig while burning bark. A schematic of the boiler is shown in Figure 1.

The original overfire air (OFA) system was typical for a boiler of this manufacturer and vintage. It consisted of circular nozzles (made from 10" pipe) arrayed in three elevations on both side walls. The nozzles were arranged to deliver the air tangentially, each level with its own firing circle.

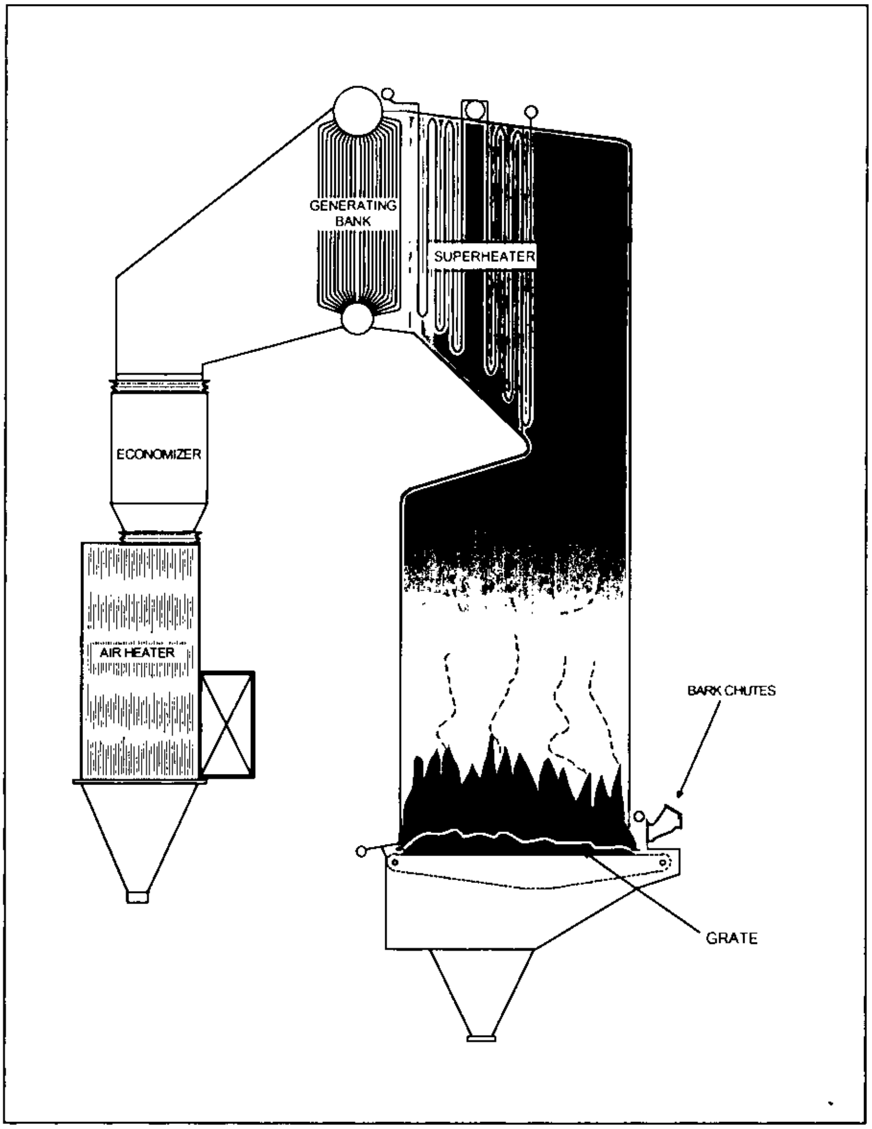

Figure 1. Schematic of the No. 2 Bark Boiler

The boiler has operated without significant changes since its start-up. Relatively recent emission testing for compliance showed that under some operating conditions carbon monoxide (CO) levels were high. At times, improvements in CO emissions could be made by co-firing gas in the boiler along with bark. The mill tried reducing the size of the OFA nozzles, but was not successful in meeting CO emission requirements without co-firing with gas.

In an effort to rid themselves of the CO emission problems, Mead Coated Board Inc. contracted Jansen to evaluate the operation of the No. 2 Bark Boiler with a focus on the OFA system. Specifically, the mill wanted to maintain emissions under permit levels while improving the operating efficiency of the unit by:

1. Reducing the reliance on burning natural gas,
2. Reducing unburned carbon leaving the boiler in the fly ash, and
3. Reducing the quantity of excess air used in the boiler.

FIELD EVALUATION

To meet these objectives, engineers from Jansen were on-site to make observations and collect data during a trial of boiler operation. During the boiler trial, the mill contracted another firm to make measurements of the flue gas composition. Trials were made while co-firing natural gas and bark and on bark alone. (The bark also included normal addition of primary clarifier sludge.) Operation of the boiler was relatively stable, although the boiler was only able to achieve a steaming rate of 245,000 lb/hr while burning bark only, partly due to limitations in fuel feed.

Subsequent analysis showed that the amount of bark fed was near to the design point for the boiler, but that the thermal efficiency and steam generation were lower than design. The design thermal efficiency while burning bark was 71%, but during the trial with bark only, the thermal efficiency had decreased to 66%. One factor that decreased the boiler thermal efficiency was the large increase in the amount of excess combustion air used: 60% compared to the design of 30%. Another factor that decreased the steam generation rate was that the feedwater temperature was 300°F compared to the design of 370°F.

The boiler was typically operated with these high amounts of excess air to maintain acceptably low levels of CO from the furnace. Very high levels of excess air are typical for boilers with air delivery systems that result in poor mixing, such that combustion rates are low.

Problems with the control of excess air were compounded, since:

- the combustion air flow monitoring system was not accurate,
- the boiler could not be reliably operated on automatic air flow control,
- the boiler flue gas oxygen analyzer was out of calibration,
- the oxygen meter was located downstream of the tubular air heater so it was biased by air heater leakage.

Recommendations were made to alleviate these problems in conjunction with installing a new OFA system similar to that previously described in the literature [1]. The OFA system design included Computational Fluid Dynamic (CFD) modeling to evaluate alternatives. The primary purpose of the modeling was to quantify gas flow patterns, O_2 and CO levels, turbulence, temperatures, etc. for different OFA delivery strategies in order to validate the number, location, and operation of our proposed design.

COMPUTER MODELING

The modeling calculations were carried out using FLUENT V4.5 CFD software. This general purpose modeling software has previously been reported for modeling biomass combustion [2]. In this case, the base version of the software was customized for solid fuel (i.e., wood, bark, sludge) burning on a grate. Since the intent of the model was to evaluate the effect of the air systems on mixing in the lower furnace, only the region of the boiler up to the nose arch was modeled. This allows for the majority of combustion, but it should be noted that some residual combustion will occur as the gases flow into the upper furnace and past the superheater. As an example, the kinetics for the reaction of CO with O_2 do not become limiting until the gas temperatures decrease to approximately 1400°F, as would be the case at the exit of the superheater.

The modeling calculations were carried out by specifying the location of fuel combustion on the grate according to the rates of drying, volatiles release, and char combustion. The model assumed that drying was biased towards the rear of the boiler, volatiles release towards the center, and char combustion towards the front to approximate the effect of the distributors throwing the hog fuel towards the rear of the boiler, and then the fuel drying and burning as it travels towards the front of the boiler on the grate.

Moisture that is released during drying requires heat and gives off water vapor. The volatile gases released were made up of the following five components:

1. H_2
2. H_2O
3. CH_4
4. CO
5. CO_2

The combustible, volatile gases were burned with oxygen at a rate according to the concentration of the gases, the kinetic rates of the reactions, and the amount of turbulent mixing. The kinetics of CO depletion by combustion were described by the following expression from the literature [3]:

$$d[CO]/dt = 1.3x10^{8}x[CO][O_2]^{0.5}[H_2O]^{0.5}\exp(-1.26x10^{8}/RT)$$

where the rate is in kmole/m^{3}s and the concentration of gases in kmol/m^3.

The turbulence reaction parameters were given by the Magnussen model and derived using the k-ε turbulence model [4]. Char combustion of the fuel particles produced heat on the grate, used up oxygen from the undergrate air, and produced CO that could be subsequently burned as described previously.

Heat that was produced by combustion was transferred to the furnace walls, primarily by radiation. The emissivity of walls was set at 0.6 and the emissivity of the gases was calculated according to the local concentrations of H_2O and CO_2 and the gas temperature.

These calculations in the model allowed for the determination of O_2, CO, and flue gas temperature at the furnace outlet, which were used to compare the effectiveness of alternative means of air delivery.

In the model, combustion air was delivered from undergrate, through the overfire nozzles, through the wood spouts, and through the tangentially-fired gas burners. It should be noted that even when natural gas was not being fired, a significant fraction of combustion air was used for cooling of the burner air registers.

The partition of combustion air at upgrade conditions is shown in Table 1. Gas flow from the cinder reinjection system was also included in the model. The gas flow through the cinder reinjection nozzles was a combination of flue gas and eductor steam.

Table 1. Combustion Air Distribution

	Units	OFA Upgrade
Undergrate Air	% of CA	55
OFA	% of CA	30
Burners	% of CA	10
Wood Spouts	% of CA	5

Description of Cases

The intent of the CFD modeling work was to understand the problems with the existing OFA system and to identify a system:

1. that would provide the required combustion improvements,
2. that could be economically installed,
3. and could be operated easily.

Previous CFD modeling work carried out in our offices showed that OFA systems employing a large number of small nozzles operating at high pressure and arrayed in multiple levels were generally ineffective. The small, closely spaced nozzles result in poor mixing and higher emissions of combustible gases.

The preferred approach was to use relatively few (less than a dozen) nozzles of sufficient size to provide up to 50% of the combustion air at less than 10 in. wg of pressure. The low pressure requirement meant that the system could be implemented without installing a new forced draft fan. Installing the nozzles on the side walls was much less expensive as there were few interferences.

The CFD modeling work was carried out to ensure that placing the nozzles on the side walls would give equal combustion performance as the more conventional approach of putting the nozzles on the front and rear walls. Since the OFA jets needed to supply the oxygen and mixing needed for combustion, the model would show the best spacing and number of nozzles. The main cases considered were as follows:

- *Case A*. Existing OFA System
- *Case B*. High-Energy OFA System - Large nozzles on the side walls
- *Case C*. Large OFA nozzles on front and rear walls
- *Case D*. Large/Small OFA nozzles on front and rear walls

In the upgrade cases modeled, the OFA nozzles were approximately 45 sq. in., and an OFA windbox pressure of 7 in. wg was adequate for the required flow. This pressure represented a velocity of 235 ft/s.

The velocity is achieved with a high energy air nozzle designed for low pressure losses shown in Figure 2.

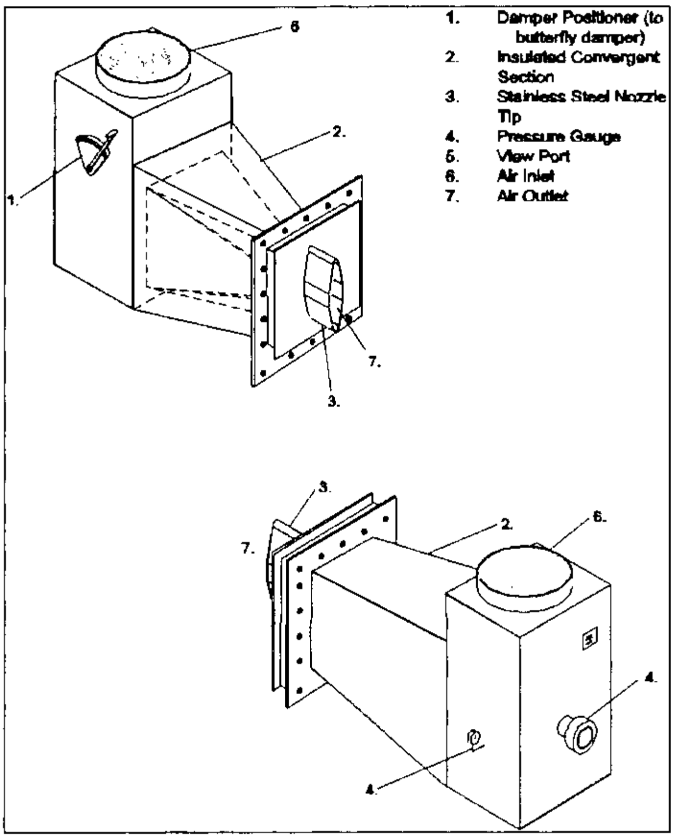

Figure 2. High Energy Combustion Air Nozzle™ for Bark Boilers

Results of CFD Modeling

Examination of Table 2 reveals that the existing tangential OFA delivery case resulted in the highest concentrations of CO at the furnace outlet. Also, the furnace flue gas exit temperatures (FGET) were predicted to be the highest for this case.

Table 2. Flue gas conditions at the nose arch level

Case	O_2 %	CO index	FGET °F
Case A	3.9	100	1920
Case B	3.2	28	1860
Case C	3.2	68	1820
Case D	3.1	78	1830

Figure 3 shows a cross section of boiler with the gas velocities at one level of the tangential OFA. As can be seen from the figure, the air jets do not penetrate into the center of the furnace, resulting in stratification of oxygen towards the walls and combustible gases in the center. Also, the amount of turbulence in the furnace was low due to the mode of OFA delivery. Both of these factors combined to result in much reduced rates of CO combustion.

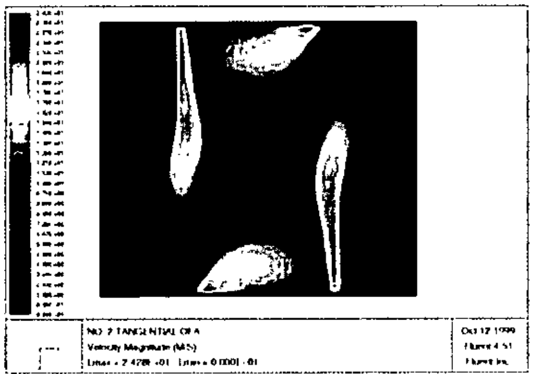

Figure 3. Tangential OFA Jets

For comparison, the CFD results of the OFA air jets issuing from the high energy air nozzles are shown in Figure 4. The interlaced jets fully penetrate into the boiler such that the combustion air and combustible gases are mixed, giving lower emissions of CO.

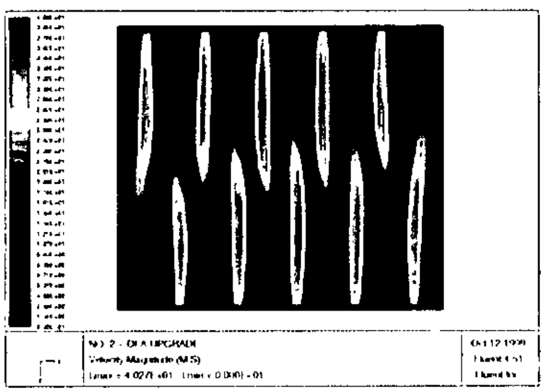

Figure 4. Interlaced OFA Jets

The air arrangements in Case C and D gave better CO burnout than the tangential OFA delivery but not as good as the interlaced OFA nozzles on the side walls. The better burnout for the nozzles on the side walls was partially due to the boiler being somewhat rectangular: it is 20'11" wide and 23'11" deep. Consequently, the jets on the side walls had less distance to travel than from the front and rear walls and the jets were better spaced on the side walls.

The arrangement of large and small air nozzles was an alternative to interlacing but the CO results showed poorer performance.

For the cases evaluated using high energy OFA nozzles, the arrangement with a ratio of 80% OFA/UG air gave the lowest levels of CO. This would be the preferred configuration if the amounts of undergrate and burner air can be maintained at base levels. The case with additional burner air was somewhat surprising in that the amount of CO at the furnace outlet almost doubled. The reason for this was that the air from the burners was ineffective in providing mixing of air and combustibles, and reducing the amount of overfire air reduced combustion rates in the lower furnace.

The use of four high energy OFA nozzles per side, rather than the base configuration of five, resulted in a marginal increase in CO at the furnace outlet. Based on the potential benefits of additional nozzles (i.e., turn down, operational flexibility, etc.), five nozzles per wall would be the preferred arrangement.

In general, there is an inverse relationship between flue gas oxygen and CO levels, the level of which is somewhat boiler and air system dependent. To establish this curve, two cases were run with additional air delivered through both the undergrate and overfire air systems and one case was run with less excess combustion air. The results showed a "knee" in the curve occurs at approximately 3.5% O_2. With the high energy OFA system, additional combustion air beyond this point has diminishing benefits in reducing overall CO levels. It should be noted that the design for the OFA system specifies 30% excess combustion air, which corresponds to a flue gas oxygen level of 3.6%.

IMPLEMENTATION OF NEW OFA SYSTEM

The equipment design and fabrication phase of the project included two visits to the mill to collect equipment information, drawings, and take field measurements. As part of the project, the following new equipment was supplied:

- Ten high energy combustion air nozzles
- OFA ducting to both sides of the boiler
- Fabric expansion joints
- OFA control dampers
- Tube panels to replace the existing tube openings
- Single tube bends for the new OFA air nozzles
- Air mass flow meters

The equipment was installed during a seven-day outage. The air system required additional time because more pressure part welds were required to close the large tangential OFA openings. More typically, new OFA nozzles could be installed in four to five days. The arrangement of the new OFA nozzles is shown in Photo 1.

In addition to the mechanical work, the boiler controls were upgraded to improve the combustion air control and O_2 trim. Other control loop improvements included load following, furnace draft, and drum level control. These upgrades, in addition to the OFA modifications, improved the boiler's ability to run in automatic mode.

Photo 1. OFA Nozzles on the East Wall

OPERATING EXPERIENCE

The boiler was started up during the first week of September. After a successful hydro, the fans were started up and the dampers and equipment checked.

The new hot-wire anemometer mass flow probes were calibrated with field traverses and this information was also used to tune the existing foil-type air flow instruments. Once the boiler was brought on-line on gas, the various control loops were tuned for reliable control over steam production and combustion air flow.

This was followed by a few days of optimizing air and bark delivery. Typical conditions for operation are shown in Table 3, along with the design and projected upgrade conditions. One item of note is the relatively large amount of excess air after the OFA upgrade. This is directly attributable to the higher than expected amount of leakage air. Close consideration was given to the burner dampers during the outage; however, the extra 60,000 lb/hr of leakage air was not corrected. The importance of the leakage air is that it does little to contribute to combustion and reducing CO emissions.

After a few weeks of operation, an independent stack emissions testing company was brought in to make measurements of the flue gas to ensure that the boiler was meeting the guaranteed emission levels. Over a four-hour period, the average emissions were as follows:

	ppm	**lb/MM Btu**
CO	288	0.32
NO_x	119	0.21

Thus, it was demonstrated that the boiler could meet the emission requirements of 0.4 lb/MM Btu for CO and 0.3 lb/MM Btu for NO_x while burning hog fuel and sludge without co-firing natural gas. Other benefits of the upgraded air system and controls for the boiler meant that the boiler could reliably be run in automatic mode while following swings in steam demand from the rest of the mill.

Table 3. Comparison of Operating Conditions				
Parameter	**Units**	**Design**	**Upgrade (8/99)**	**Post-upgrade (9/99)**
Steam Flow	lb/hr	300,000	280,000	310,000
Drum Pressure	psig	935	935	860
Steam Pressure at Superheater Outlet	psig	890	890	804
Steam Temperature at Superheater Outlet	°F	825	825	831
Feedwater Temperature to Economizer	°F	370	300	370
Total Heat Input	million Btu/hr	451	449	480
Dry Bark Flow Rate	lb/hr	52,900	52,700	56,400
Bark Moisture Content	%	45	45	45
Hog Fuel HHV, dry	Btu/lb	8,513	8,513	8,513
Total Combustion Air Flow Leaving TAH	lb/hr	NM	365,400	487,000
Undergrate Air Flow	lb/hr	NM	211,600	237,000
OFA Flow	lb/hr	NM	115,400	149,000
Natural Gas Burner Air	lb/hr	NM	38,400	101,000
Wood Distributor Air	lb/hr	NM	19,200	[1]19,200
Total Combustion Air Flow to Unit	lb/hr	385,650	384,600	[2]474,000
Excess Air	%	30	30	50
Excess Oxygen, wet	%	3.6	3.6	[3]5.4
OFA Air Temperature	°F	385	450	[3]504
Supply Pressures to Undergrate	in. wg	1-2	1-2	0.2
Supply Pressures to OFA	in. wg	NM	6-8	7.1/7.2
OFA Nozzles in Service	No.	12	10	10
Air Flow Splits (% of total combustion air flow)				
Undergrate Air from TAH	%	NM	55	47
OFA From TAH	%	NM	30	29
Natural Gas Burner Windbox Air	%	NM	10	[3]20
Wood Distributor Fan Air	%	NM	5	[1]4
NM = Not measured; [1]estimated; [2]calculated, [3]due to burner leakage				

CONCLUSIONS

As mills are faced with meeting more stringent emission requirements from bark boilers, along with the requirement to burn poorer quality fuels, including sludge, then the air system requirements are more demanding.

It is important that the design of the air system can meet the emission requirements and that the system can be easily operated and controlled. Also, the installation should be as simple as possible to reduce the overall cost and downtime required for the project.

Prior to embarking on the design for a project of this type, the engineers should have a good grasp of the problems and the required solution. CFD modeling is useful tool for evaluating different OFA arrangements and operating strategies. Even though CFD analyses are fairly difficult and time consuming, they provide information that is not available by any other means.

Successful implementation requires close communication by all parties involved. While a proper OFA system is required, attention must also be given to the control system. Along with other basic boiler control functions such as steam load following and furnace draft control, it must also be able to provide the correct amount of undergrate and overfire air at the right pressure.

ACKNOWLEDGEMENT

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ALSTOM

Power Boiler Upgrades - A Validation of Design by CFD Modeling

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Abstract
A biomass fired power boiler has been upgraded to improve the combustion within the lower furnace. This was accomplished primarily by upgrading the design and operation of the boiler combustion air system. The project design parameters as well as the test results obtained will be reviewed. The boiler capability to burn biomass fuel was increased by 15-20%. Computational Fluid Dynamic (CFD) modeling was used to simulate the boiler. Several overfire air arrangements were compared to the baseline system, specifically front/rear and sidewall layouts. The predictive modeling indicates that there are distinct advantages in a front/rear wall overfire air admission over a side to side configuration. A comparative review of these designs is presented.

Introduction

Biomass fired power boilers are an important part of the total plant energy balance. The role of this boiler has been steadily changing over the last 10-15 years. Originally the boilers dealt with relatively good waste wood and some bark. The efficiency of the boiler was not a primary concern. Usually to make full steam load a significant amount of auxiliary fuel was fired. Also particulate emission requirements were less stringent compared to today's standards.

Today, most of the mills are under pressure to reduce auxiliary fuel firing due to the high cost of this fuel. In addition the biomass fuel has changed significantly. The clean dry white wood is now being used for other products and is no longer burned in the boiler. It has been replaced by more hog fuel and fuels from alternate sources that were not previously considered primary fuels. These are sludges, such as primary, secondary and de-inking. There has been a drive to burn these fuels to the maximum possible without auxiliary fuel at all. Needless to say this has presented a major challenge to the industry.

There has been considerable work done on improving the combustion of biomass boilers. An important tool for these evaluations is Computational Fluid Dynamics (CFD). With CFD analysis, considerable improvement has been made to the combustion capability and operation of biomass boilers. With it, the boiler combustion system can be simulated and improvements evaluated prior to the physical changes being made on the boiler. The advancement of CFD combustion software has allowed the boiler details to be more accurately represented. More efficient solvers and computers have placed CFD into the design process in many industries. Alstom Power is using CFD for an increasingly large span of combustion system equipment design. With customized submodels to represent the burning of wood waste fuels, different design arrangements can be compared and analyzed to select the optimum for the project. The integration of CFD simulations with detailed performance analysis tools and retrofit experience provide a solid foundation and reduced risk when attempting to upgrade vintage units.

Background

The presentation of the results will be done in the context of a typical biomass boiler project. This project consisted of the upgrade of the bark burning capacity of the boiler by modifying the overfire air system and reducing tramp air. The economic benefits of this project are:

- Improved combustion (Increased bark consumption)
- Reduced carbon loss (Increased efficiency)
- Reduced excess air requirements (Lower fan power consumption)
- Improved flue gas temperature and velocity distribution (Reduced maintenance)
- Reduced carryover (Reduced Emissions)
- Reduced CO emissions (Improved combustion)

The overall effects on boiler operation are:

- Increased capability to generate more steam from biomass
- Increased capability to fire poorer fuels
- Increased capability to maintain self-sustaining combustion
- Decreased operating costs

Role of CFD Modeling

The upgrade of biomass boilers usually involves the modification and improvement to the boiler's combustion air system. However this is an oversimplification of scope of the project. The project is actually a total combustion system upgrade. By this we mean that all components of the boiler that play a part in the combustion of the fuel must be considered. These components are:

- Furnace Arrangement (cross-sectional area and height which affects the grate heat release rate and the residence time)
- Air system parameters such as fan capacity, air distribution to the grate, air distribution to the overfire air level, tramp air, air pressures and air temperatures.
- Fuel parameters for both the biomass and auxiliary fuels(source, fuel analysis, moisture, quality) and fuel handling (fuel distribution method, contaminants)
- Combustion grate system (grate type)
- Boiler operation (boiler load, boiler biomass load, base load)

These parameters are all interdependent. There are 'rules of thumb' for biomass firing but there is no simple design parameter such as grate heat release rate or residence time which will give a consistent result for varying conditions. This is where CFD modeling is beneficial to the design process. It can account for the varying parameters in a boiler and different cases can be run to simulate the different operating conditions and the proposed changes. The CFD model incorporates a comprehensive set of data for a combustion simulation. This data set can be examined in many different ways to compare velocity distribution, gas composition, volatiles, gas temperatures, and particle trajectories and residence time.

Boiler Geometry

The boiler modeled is a Combustion Engineering VU-40 stoker boiler with a traveling grate stoker. The furnace dimensions are 23ft.11 in. wide, by 22ft. 11 in. deep. Overall height of the drum is about 88 feet from the lower side wall headers. This boiler is a two-drum unit originally designed to fire oil and hog fuel. The boiler was designed for 410,000 lb/hr steam at 825°F and 850 psig firing either oil or hog/oil in combination. The maximum load on hog only was 350,000 lb/hr. Currently it is normally fired with 100% wood bark fed by screw feeders. The maximum boiler output on hog fuel was close to design steam flow but with very high excess air, high CO, carbon loss and carryover.

Combustion air is fed to the boiler at a variety of locations. Undergrate air is fed through the grate in four sections across the grate. Leakage air can enter around the grate at the furnace walls. The combustion air introduced above the grate enters in a variety of locations.

In the baseline (original) configuration, the over fire air is injected through the sidewall OFA ports in a tangential pattern. There are five levels of over fire air. Under current operating conditions, the lower four compartments were fully closed. There is also leakage air through the observation ports on the back and right sides. Also air is injected through the corner burners with the auxiliary fuel, and with the six cinder re-injection nozzles. A small amount of air is also introduced with the fuel.

In the retrofitted (HMZ) configuration, over fire air is injected from the front and back in an opposed pattern. For the purpose of comparisons between air system designs the cinder reinjection system is not included.

Above the auxiliary fuel burners, the unit has an arch, which directs the gas flow into the convection pass. In the convection pass are two superheater banks and a boiler bank. Gas flows from the boiler bank into an air heater. The model of the boiler stops at the inlet to the air heater. A side elevation view of the boiler is shown in Figure 1.

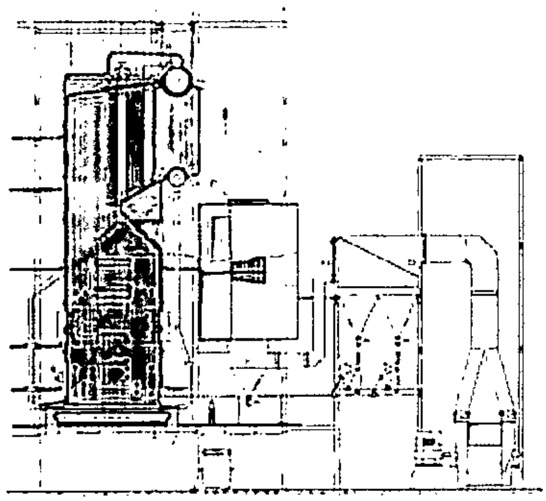


Figure 1 – Boiler Side Elevation

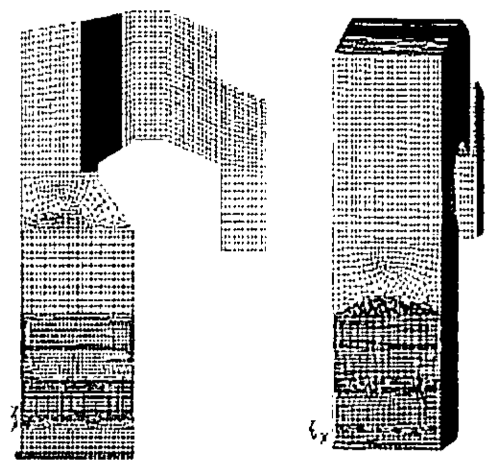


Figure 2 – CFD Mesh

Description of the CFD Model

The CFD code FLUENT was used to simulate the furnace designs. FLUENT is a commercially licensed CFD code that calculates the flow field variables selected at each cell of the mesh. The number of cells used in a model and the number of variables calculated impact the time required to solve a particular case. The higher the number of cells and the larger the number of variables, the more time the calculations take. Typically for models of this type, the initial calculation for a geometry involving combusting particles may require about 5 days of continuous computer time. For this reason, an efficient mesh is helpful. For the furnace arrangement shown in Fig 2, cells are concentrated near the overfire air nozzles and the grate. These are areas where steep gradients of temperature and gas composition are present and thus can be more accurately resolved with a finer mesh. The boiler was modeled using about 220,000 cells. This number was selected as a compromise between getting a fine resolution of the flow details and minimizing the computer time needed to complete the simulations. If necessary, the mesh can be adapted to provide additional resolution by grid adaption and refinement.

The particular simulations include the primary variables such as pressure, velocity components, and turbulence quantities, along with temperature, major gas species, convective and radiation heat transfer, and particle interactions with the gas. The Disperse Phase Model (DPM) calculates the flight of the wood particles tracking them through the heating, drying, devolatilization, and char burning phases. The Lagrangian particle tracking method provides a stochastic treatment to the particle trajectory with the deviation proportional to the local turbulence intensity. A coupling of the particle mass and momentum transfer to the gas phase is accomplished by performing a series of alternating gas phase and particle injection sweeps until a reasonable energy closure is achieved. For the treatment of the wood particles, the water vapor is evolved before the devolatilization process begins. The ultimate and proximate analysis from the wood fuel was used along with the heating values to prescribe a 2-step reaction mechanism for the burning of the volatiles. Solid phase combustion of the char particles was based on both kinetic and oxygen mass transfer limiting rates. An important difference between the typical particle combustion models in FLUENT and the simulations of wood furnaces is that the particle diameters and burn times are long compared to pulverized coal. For that reason, along with the moving grate environment, FLUENT was customized to more efficiently handle the particle burning pattern.

Model of the Moving bed

A custom model to represent the behavior of burning particles on a travelling grate was developed and used for these simulations. Fuel particles landing on the grate follow the motion of the grate travel (from back to front). In addition to adopting the grate motion, a sticking and escape criteria is imposed.

During operation, the fuel piles tend to block off the air emerging from the individual grate keys. Depending upon the resistance characteristics of the grate, the fuel size and composition and other factors, fuel piling makes the operation of a stoker with wet fuels difficult from both an operation and computer modeling perspective. A diversity of factors, influences when a pile forms or when a jet of air penetrates through the fuel pile and cannot be easily represented in the computer model. This limitation is due to the basic limitations of the Disperse Phase Model. Each particle is tracked through space without impacting or agglomerating with other particles. While the aggregate effect of all particles are integrated and are coupled to the momentum, mass, and energy, transferred to the gas (and vice-versa), there is no specific particle to particle interaction. For example, it is not possible to represent the development of a fuel pile or a blow-through occurrence, which is typical in wood and wood waste stokers.

As a means to include the effects of the fuel piling and escape, an escape criteria is specified which allows a particle to escape into the gas stream if the ratio of the aerodynamic lift to gravity forces exceed a selected value. This allows the particles to follow in the direction of the grate and burnout completely, or if the local conditions dictate, allow the less dense particle to lift-off the grate and resume an in-flight trajectory. The two benefits of this custom model are that a. the burning particles tend to be stable and not float on the grate surface, and b. the split between particles which escapes as carryover or fall into the ash pit at the front of the stoker can be estimated.

CFD Model Results Comparisons

Modification Extents

The CFD simulations were done to show the difference between the baseline case for the existing operation of the boiler with a side wall/corner tangential over fire air system, and for the retrofit case after installation of a new horizontal mixing zone (HMZ) front/rear wall over fire air system. In addition to installing the new overfire air system, a fabric stoker seal reduced infiltration around the grate. The set of sidewall overfire air nozzles which were of limited capacity were permanently removed. The upper tangential level that provided support fuel firing was left in place.

Flow Distribution

Gas velocity plots are shown at the centerline plane of the boiler in Figures 3 and 4. Figure 3 presents contours of velocity magnitude in the lower furnace over the range from 0 ft/s to 60 ft/s. Figure 4 represents the vertical velocity magnitude for the same case. The baseline case has a plume of gas that flows up the rear wall. The vertical velocities are higher in the upper furnace for the baseline case than for the retrofit (HMZ) case indicating that the flow has more of a tendency to channel to the roof in the base case. The impact of the overfire air in the baseline case is insufficient compared to the retrofit case where the penetration of the jets and the interaction zone in the center are evident. The plot of vertical velocity shows the entrainment zones both above and below the OFA level. Figure 5 shows a surface of constant turbulence intensity for both geometries. The shear created by the overfire air jets causes turbulence and rapid mixing of the gases above the grate.

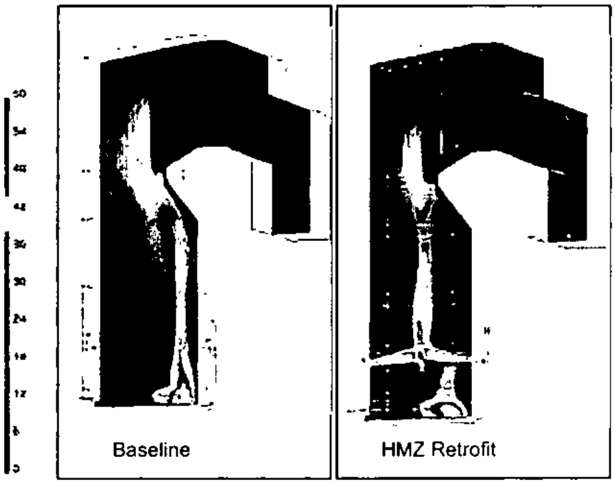


Figure 3 – Velocity Profile

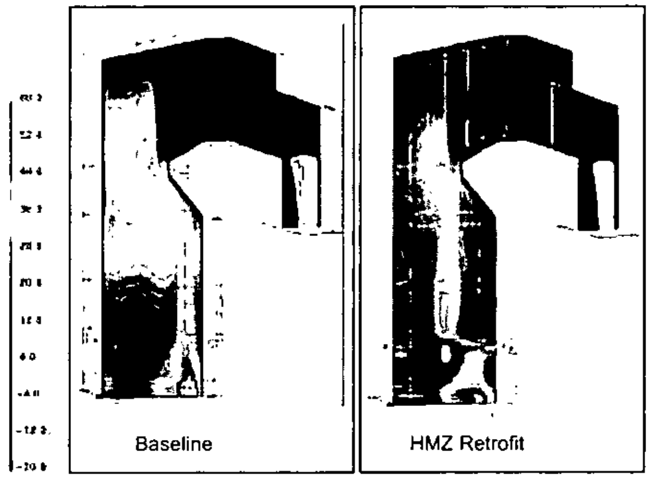


Figure 4 – Vertical Velocity Profiles

One of the benefits of the front and rear HMZ air system is a relatively uniform side to side gas velocity profile entering the heat transfer surfaces. This is shown in the comparison plot of Figure 6. Because of the large fraction of combustion air injected across the front and rear walls, the tendency to have significant gas side energy imbalance is reduced.

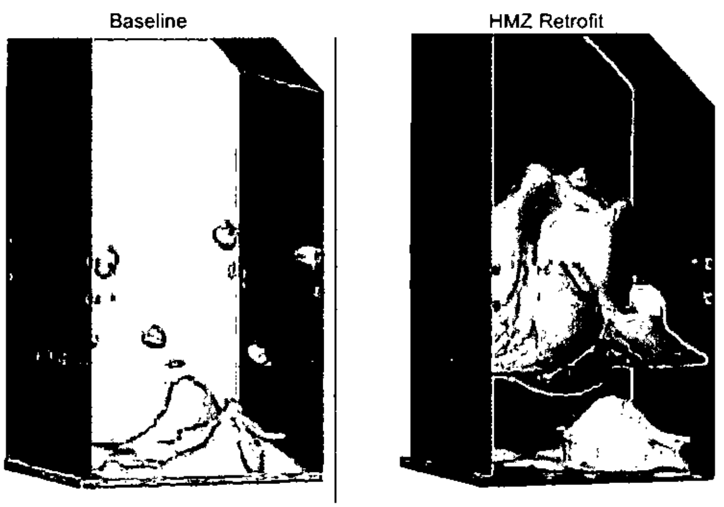


Figure 5 – Turbulence Surface

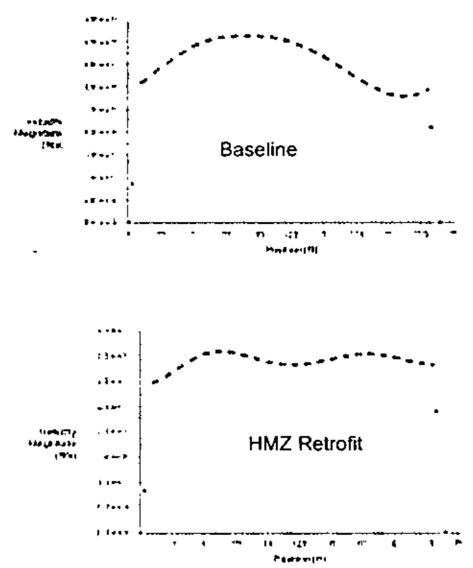


Figure 6 – Side to Side Velocity Profile

O2 and CO Predictions

Major gas species concentrations provide a relative indication of the mixing and combustion heat release patterns. The predominant feature of the baseline case was an oxygen depleted zone in the plume at the back of the furnace. This was observed in videos of the operation, and is not uncommon. The CFD predictions confirm this feature and show a clearly superior distribution for the HMZ case in Figure 7. This plot shows the range of 0.10% to 10% CO on a dry basis. The outlet concentrations of CO in the baseline case were not measured but were believed to be very high. The post retrofit CO levels were reasonably close to the predictions, although CFD predictions of CO are more difficult for solid fuel combustion situations. The oxygen distribution in Figure 8 further accents the mixing action of the new air system compared to the baseline. It is interesting to note how the low O_2 zone rear wall zone for the retrofit geometry is depleted by the mixing and entrainment action of the overfire air.

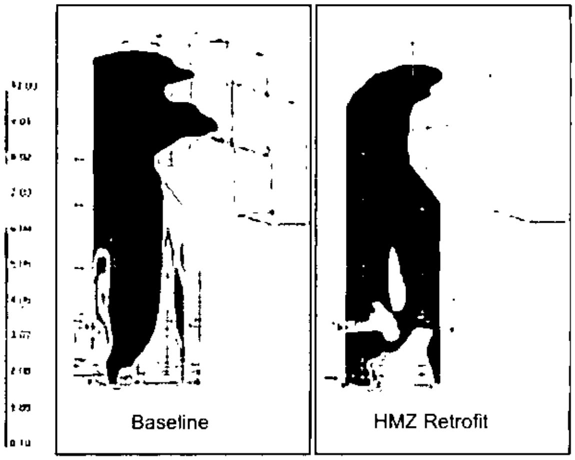


Figure 7 – CO Distribution

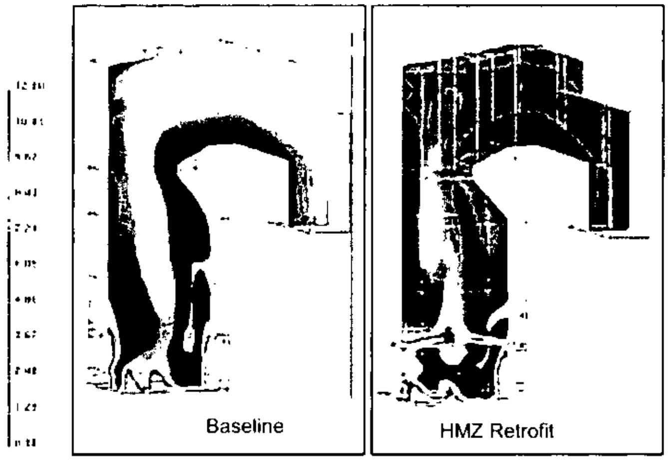


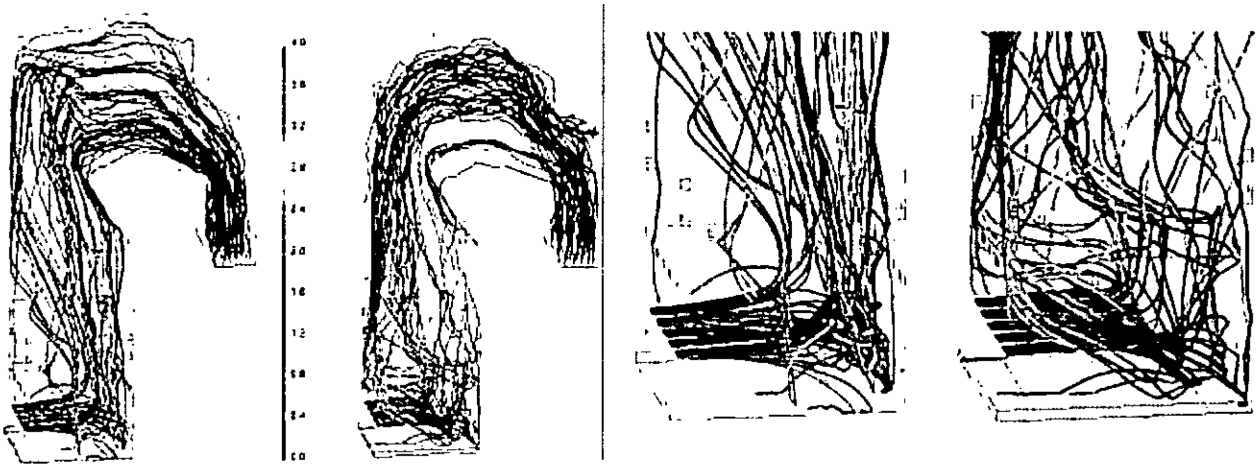
Figure – 8 Oxygen Distribution

Temperature Distribution

The temperature distribution at the centerline was in the range of 500°F to 3000°F. The baseline case shows a high temperature at the back of the grate in the center. This continues upward along the back wall past the OFA level. The HMZ retrofit case has a high temperature zone at the grate and a slightly lower temperature at the arch by approximately 50°F lower. The increased turbulence levels and higher heat release for the post retrofit condition could be exploited to burn higher moisture bark. Post-retrofit operations at the plant have been positive.

Particle tracking

The burning patterns for the fuel injected from the distributors was studied carefully to better understand the differences in the two arrangements. The fuel system for this boiler has 5 mechanical wood fuel distributors located across the front wall. The mass distribution to each distributor was proportioned in the CFD model according to the screw feeder speeds, with the assumption that the flow varied linearly with feeder speed. As reported from the plant operations, the right side distribution at distributors 4 and 5 deviated from a normal bell-shaped distribution. This was included in the baseline run. However, for the HMZ case the distribution to the five feeders followed a normal bell shape. At each distributor, 8 different particle size classes were injected. A distinctly different trajectory for the particles was found to exist between those burning in suspension and those that remain on the grate. The smallest diameter class of particles (1/16") is plotted as a function of residence time in Figure 9. The smoother appearance of the tracks for the baseline case is due to lower turbulence levels. There is a high concentration of particles that sweep up the rear wall. The tracks for the HMZ retrofit case follow a more dynamic pattern, due to the OFA jets.

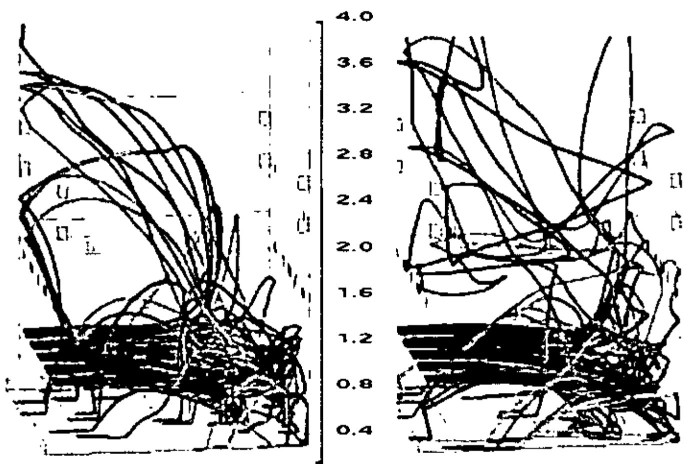


Baseline HMZ Retrofit Baseline HMZ Retrofit

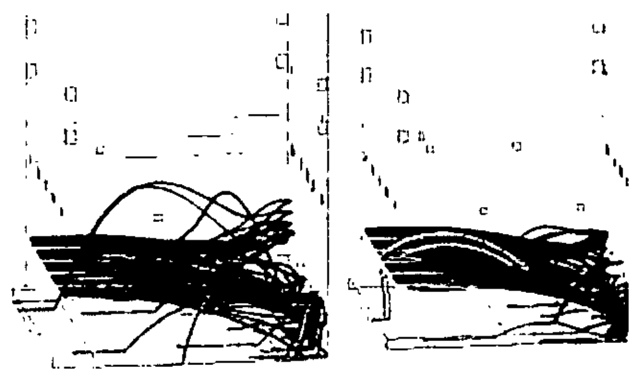
Figure 9 & 10 – Particle Tracks for 1/16" Particles

A view of the same particles closer to the grate in Figure 10 shows the tendency of the particles which arrive at the rear wall to be swept back to the front wall along both the left and right walls. This may support the reason for the bark distribution. The amount of particles that migrate to the front wall for the retrofit case is more substantial.

Tracks for the larger (1/4") particles near the grate are compared in Figure 11. At this size level, many of the particles remain on the grate. Many of the particles which are in suspension have residence times significantly longer than 4 seconds, which is the range used for these two plots. For the large particles with a diameter of ¾", the time scale was increased to 60 seconds for the comparison plot of Figure 12. For these particles, the differences between the baseline and retrofit case are not apparent. It is clear that there is a need to examine the influence of particle diameter distribution on the stoker performance.



Baseline HMZ Retrofit



Baseline HMZ Retrofit

Figure 11 – Particle Tracks ¼" Particles

Figure 12 – Particle Tracks ¾" Particles

Validation of Results

The CFD results for particle tracking and CO levels are summarized. A net reduction of 66% the pre-retrofit ash disposal rates as measured in truckloads was observed. The CFD model also showed about the same reduction in unburned carbon. Detailed isokinetic or other dust sampling methods were attempted but proved unfeasible in the mill operation. The longer term averaging as truckloads units is

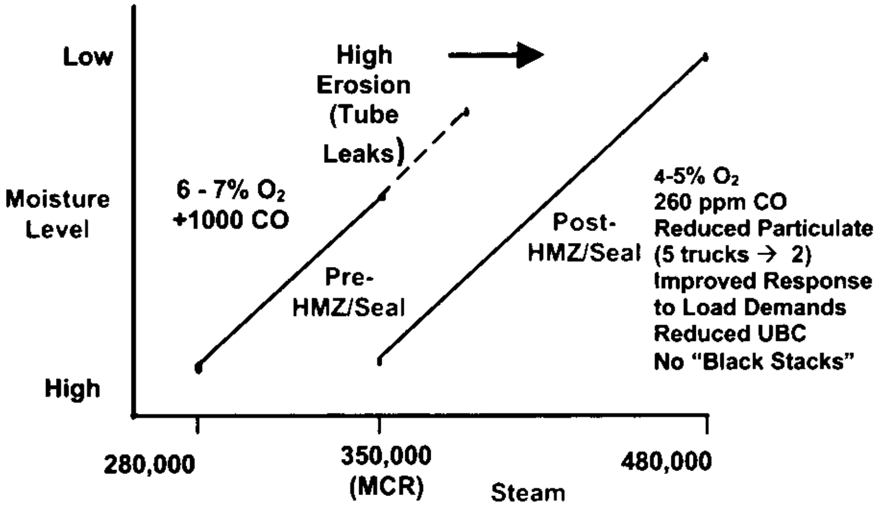


Figure 13 – Boiler Performance Summary

the better indicator. Because the fuel contained only 2% ash by analysis, it was surmised that the majority of the residue was carbon.

The boiler capacity achieved on biomass firing was significant. Prior to the upgrade the boiler was capable of only 280,000 lb/hr steam firing a high level moisture fuel. When the moisture level dropped the capacity achievable increased to 350,000 lb/hr. At this load, the boiler suffered from high erosion and the boiler operation could not be maintained without tube failures. After the upgrade, the boiler biomass firing capability increased to 350,000 lb/hr on high moisture fuel and up to 480,000 lb/hr on low moisture fuel. This represents a 25% minimum capacity increase. The CO levels after the retrofit were reduced from 1000 ppm to 260 ppm, a 75% reduction from the pre-retrofit case. Upper furnace probing would be useful to provide information about the CO levels in the upper furnace. See Fig.13 for a graphical summary of the boiler performance.

Alternate Overfire air system designs

During the design phase there were questions raised as to the best arrangement for the overfire air system. The new design improved the combustion due to the higher momentum mixing and due to the reduction of tramp air or ineffective air. Although the design approach has been to provide the overfire HMZ air nozzles on the front and rear walls, it was decided to model an altenate overfire air arrangement located on the side walls at the same elevation as the retrofit HMZ design. The alternate design consisted of an interlaced arrangement of overfire air nozzles across the sidewalls. The results of this study showed that the front rear arrangement performed better.

The results of the model simulations are presented here in Figures 14 & 15. These plots detail the relative performance of these two OFA design cases. These models provide aerodynamic, temperature and species information for comparison purposes, but should not be used for predicting performance. Interpretation of the two different arrangements follows.

Flow distribution

The side wall overfire air design has a tendency to push the majority of the airflow to the center of the boiler, when viewed from the front wall. The effect of this side to side velocity distribution is a much higher gas mass flow entering the superheater towards the center than on the sides. This may cause metal temperatures to occur in the central superheater tubes due to the higher gas flow and heat transfer. The magnitude of the unbalance is about the same as in the original baseline case. The front/rear HMZ air system design effectively spreads the gases across the entire width of the furnace and superheater. Also, the analysis of the front/rear HMZ shows that the side to side wall peak velocity is closer to the average than in the alternate side wall overfire air design by several feet per second.

The gas velocity plots show that both systems have a downward component of velocity in the center of the boiler below the air nozzles, due to the collision of the jets. Above the air injection zone the system show uniform upward velocity front to back. This pattern is essentially the same except for both arrangements except that one is rotated 90°. In both cases, the carbon burnout is vastly superior to the baseline case. The impact of the side wall arrangement on particle trajectory and on grate piling were not evaluated. More modeling work is required to further understand the performance of the alternate

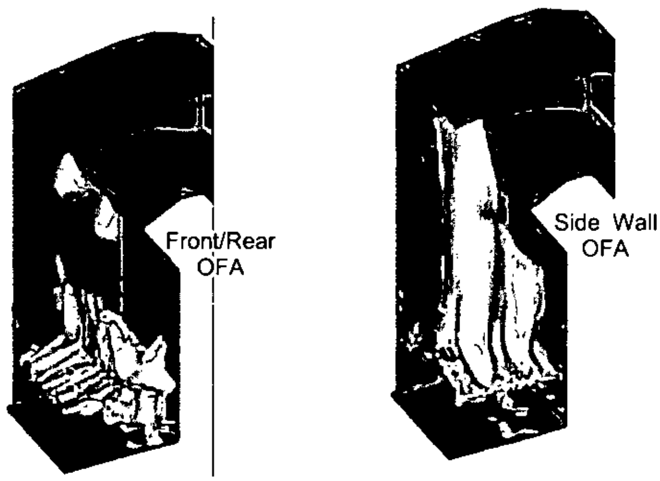


Figure 13 – Velocity Surface Profile 40fps

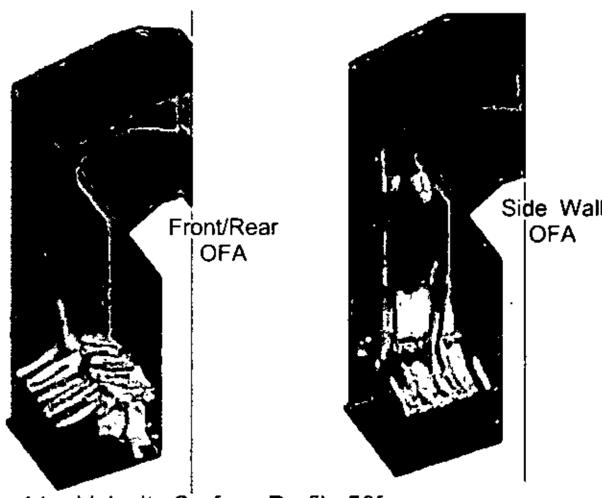


Figure 14 – Velocity Surface Profile 50fps

arrangements on grate piling and particle trajectories. This modeling work to understand the benefits or deficiencies of sidewall versus front/rear wall OFA will require a more generic comparison free of some of the complicating factors that relate to the geometry and firing mode. For example, the grate fuel distribution used may not be optimal for both OFA configurations.

Conclusions and Recommendations

A CFD model was constructed which described the bark fired traveling grate boiler. This model was used to show relative performance for different combustion air system designs. This study showed an improvement in furnace mixing of the air and fuel for the retrofit air system arrangement. It also showed a more uniform gas distribution from the OFA level through the convection pass. Both of these effects contribute to better fuel combustion and less ash carryover.

The HMZ aie design mounted on the front and rear walls was found to perform better than alternative designs located on the side walls. The front and rear HMZ air system had more uniform mixing, less carryover, and better carbon conversion.

This study showed an improvement in ash carry over with the alternate side wall air case, however the over all carbon carryover was not as good as the front/rear wall HMZ air system, resulting in a higher carbon in the carry over solids. Velocity distribution with the side wall systems are very close to each other but are not as evenly distributed across the furnace outlet plane as the front to back HMZ system. It is emphasized that both of side wall air systems investigated as well as the front/rear air system are vastly superior to the baseline case.

The CFD modeling showed that the side wall air system had similar flow characteristics, and that the side wall air systems were fundamentally different from the front and rear HMZ air system in three areas. First, the side air systems had a tendency to force the gas flow to the center of the boiler. This caused a higher flow rate into the superheater tubes in the center, and lower flow to the outside tubes. Second, the ash carryover was reduced but the total carbon carryover was higher than in the front HMZ case. Finally the bottom ash carbon content was lower in the side wall HMZ case than the front wall HMZ case. The side wall system seemed to be no worse than the baseline case in these comparisons but not as good as the front wall HMZ case. Tube metal temperature problems caused by the gas flow imbalance from the side wall air system are a possibility.

The test results validate the results obtained from the CFD modeling. The test results indicate the overall biomass firing capability has increased 25% over the maximum current capability. This increase in combustion capacity is coupled with less excess air, reduced carbon loss, and reduced power consumption. These results are typical for the installation of the improved overfireair system. Further projects have been reported previously (Ref.1.)

Based on the success of the modeling, further work will be undertaken to quantify the effects of different parameters on boiler performance. The most significant are the fuel moisture, fuel size distribution and type of grate installed on the boiler.

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BIOMASS BOILER CFD MODELING AND DESIGN VALIDATION

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ABSTRACT
A bark-fired power boiler was recently upgraded with a modern overfire air system and other components including a fabric stoker seal to reduce infiltration. Capability to burn high-moisture bark was significantly increased, while at the same time ash quantities trucked to landfill dropped to nearly 1/3 of the pre-retrofit levels. An important aspect of this successful project was the use of Computational Fluid Dynamics (CFD) modeling. After representation of the baseline conditions, the model was used to assess the retrofit modifications. Visualization of the CFD results was useful to identify areas for improvement. While the predictions were found to compare reasonably well with post-tests, it remains challenging to quantify biomass boiler performance without detailed baseline airflow distribution measurements and accurate characterization of the grate burning processes. Results were found to be very sensitive to aerodynamic behavior of wet and dry bark. This result is discussed in conjunction with CFD model developments.

INTRODUCTION
Considerable progress has been made in the pulp and paper industry toward improving the combustion performance of air system designs of biomass boilers. These improvements have been applied to both new and retrofit installations to increase bark firing capability and reduce dependency on auxiliary fuels. An important tool for this development is Computational Fluid Dynamics (CFD). With this tool, an existing unit can be simulated and improvements evaluated prior to physically changing the boiler. The improvements of CFD combustion software used by many different vendors are significant [1-3] and are used to analyze boiler combustion and mixing performance. ALSTOM uses CFD for many different types of combustion system equipment design. With customized submodels to represent the burning of wood waste fuels, different design arrangements can be quickly analyzed. The combination of CFD simulation in conjunction with traditional performance analysis, along with experience provides the basis for estimating the upgraded potential of vintage units.

The specific submodels for predicting NOx and trace gas emissions appearing in both commercial and proprietary CFD codes are becoming increasingly complex. However, incorporation of sophisticated submodels alone does not necessarily imply that these CFD predictions are more accurate. The representation of the actual combustion conditions on a travelling grate can dominate the entire solution. It remains extremely difficult to develop an accurate steady-state model of a biomass stoker. This is in part due to the dynamics of fuel piling and the difficulty in characterizing the aerodynamic behavior of hogged fuels. Research continues is this area. The goal is to develop improved methods to analyze the fuel, fuel admission equipment, and the grate burning process in order to improve the CFD simulation of biomass boilers over a range of potential fuel compositions. The methods used to develop and improve these tools will include fundamental characterization, field testing and validation. In conjunction with more rigorous bark evaluation, it is likely that more comprehensive pre-retrofit measurements will still be required. For example, it is often difficult to quantify the actual combustion air and its distribution. Leakage rates are often under-estimated and can have a significant impact on the operation of a bark boiler. Estimating these flows can seriously impact the results and potentially the conclusions of the CFD study. As the fleet of older units is forced to meet lower emissions and provide more steam for plant electrical load, studies which include testing and CFD modeling will improve the economic assessment of biomass and power boiler upgrades.

OBJECTIVES
Given the increase in fuel and energy costs facing our nation, paper mills must evaluate the cost-effectiveness of renovating old equipment to provide steam for process and power generation needs. Power boilers are quite common in the mill environment, burning an ever changing mix of wood, wood wastes, hog fuel and other various solid and gaseous waste streams in the process. With fuel and disposal costs rising, the economics of upgrading older power boilers is now becoming favorable. Such units, which had been largely ignored in the past are now

potential candidates for renovation. As part of the costs analysis, modernization can provide many benefits. These include:

- Increased steam capacity
- Higher boiler efficiency
- Lower gas and solids emissions
- Decreased operating and maintenance costs

While these objectives are clear, the task of quantifying these factors in order to compute economic payback is difficult without a detailed study of each boiler. This usually involves a review of the hardware and components to determine the scope. Many successful renovations have been documented and described in the literature. An increasingly useful tool for equipment suppliers is the use of CFD. The use of CFD to assist in projecting the improvements to recovery boilers has been extensively documented. Many of the air system design strategies developed for CRU's are equally applicable to power boilers. However, power boilers must be capable of firing a wide range of low-grade fuels. This requires that the combustion capabilities of the equipment be analyzed using different tools. CFD is one such tool.

ROLE OF CFD MODELING

The upgrade of biomass boilers usually includes the modification of the boiler's combustion air system. However this is an oversimplification of the scope. The project is actually a total combustion system upgrade. Because each retrofit is different, all of the subsystems must be studied to be sure the boiler can attain the desired performance. Some of the variables and equipment which are carefully reviewed include:

- Furnace geometry: cross-sectional area and height for computing grate and volumetric heat release rates and bulk residence times.

- Air system equipment: fan capacity, air heater performance and condition, air flow parameters and flow measurements, distribution controls and damper conditions of the grate and overfire air ports, and infiltration - including location and quantity.

- Fuel properties and handling equipment: composition, size distribution, variability and furnace delivery equipment

- Combustion grate system: condition, operating characteristics, controls

- Boiler demands: boiler load, boiler fuel mix, and control system.

These concerns are all important and interdependent. There are general 'rules of thumb' for biomass firing used by designers, but there is no simple engineering guideline, such as grate heat release rate or volumetric heat release rate (residence time) which yields consistent results for the wide range of existing boilers and operating. This is where CFD modeling can support the design process. By simulating a range of conditions, the impacts of different scenarios can be evaluated. Alstom has found that accurate air distribution and infiltration sources are difficult to obtain from most boilers. When the effort is taken to measure these flows by duct traverses and flow meter calibration, the resulting information is beneficial for both the CFD model accuracy, and thermal performance analyses. Older units are particularly troublesome because they lack good flow measurement devices and monitoring equipment. Conducting detailed measurements can help identify components which need attention or repair. After establishing a baseline CFD model calibrated to field measurements, different retrofit arrangements are modeled and examined by comparing velocity distribution, gas composition, temperatures, and particle trajectories and residence times.

GENERAL DESCRIPTION OF THE CFD MODEL

The CFD code FLUENT was used to simulate this VU-40 furnace design. FLUENT is a commercially licensed CFD code that has capabilities to simulate flow, temperature, chemical reactions, and heat transfer. The FLUENT CFD code is widely used for the power, process and automotive industries for simulation of components and systems. Fluent simulations have been widely published for CRU and biomass furnaces. For the travelling grate biomass furnace, Fluent version 5, which includes a fully unstructured solver and improved radiation heat transfer methods (discrete ordinates) was customized to represent combusting particles on a grate. This custom model represents the behavior of burning particles on a travelling grate. Fuel particles landing on the grate can follow the motion of the grate travel (from back to front). In addition to modeling the grate motion, a sticking and escape criteria is imposed.

During operation, the fuel piles tend to block off the air emerging from the individual grate keys. Depending upon the resistance characteristics of the grate, the fuel size and composition and other factors, fuel piling makes the operation of a stoker with wet fuels difficult from both an operation and computer modeling perspective. A combination of factors influence when a pile forms or when a jet of air penetrates through the fuel pile. These are not well-represented by the steady-state simulations. This is due to the inherent limitations of the Disperse Phase Model in FLUENT and other codes. Each particle is tracked through space without impacting or agglomerating with other particles. While the aggregate effect of all particles are coupled to the momentum, mass, and energy, transferred to the gas (and vice-versa), there is no specific particle to particle interaction to treat this collection of particles as a fuel "matte". Therefore it is difficult to represent the true growth of the fuel pile or a blow-through occurrence, which is a dynamic process occurring more frequently when firing wet bark. Experimental studies on wet fuel ignition have even observed the flame front to propagation from the bottom of the pile [5].

As a means to include the effects of the fuel matte which tends to trap the particles, an escape criteria is specified which allows a particle to escape into the gas stream if the ratio of the aerodynamic lift to gravity forces exceed a selected value. This allows the particles to follow in the direction of the grate and burnout completely, or if the local conditions dictate, allow the less dense particle to lift-off the grate and resume an in-flight trajectory. The two benefits of this custom model are that a.) the burning particles tend to be stable and not float on the grate surface, and b.) the split between particles which escapes as carryover or fall into the ash pit at the front of the stoker can be estimated. These modifications are insufficient to provide accurate prediction of the fuel piling processes. Other CFD methods which could be invoked include time-dependent multiphase calculations for the fuel pile on the grate along with drying and surface combustion. However, the additional computational burdens are huge, and not warranted. Determination of the physical properties within the fuel pile such as permeability, density, and effective surface area as a function of time and position is still beyond our state of development. The CFD methods used today can at best, provide an approximation of the general burning pattern on the grate.

Above the grate, representation of the particles burning in suspension is suited to the framework of the Lagrangian disperse phase methods in most CFD simulations presented. However, there is also need for improvement in this area with respect to characterizing the bark stream entering the boiler. The particle trajectories, and hence the suspension burning percentage, has been found to be very sensitive to the drag coefficients [6] used in the Lagrangian particle tracking models. One area currently being studied is the quantification of aerodynamic characteristics of bark fuels of different composition and moisture levels. However, it is difficult to quantify the as-fired size distribution of wet fuel because of agglomeration and clumping which tends to hold the smaller particles together. Dry sieve analysis are very different from wet fuel properties for that reason. It is therefore difficult to accurately prescribe sphericity factors for the aerodynamic drag calculations. Thus the predicted split between "suspension burning" vs. "grate burning" is sensitive to the assumptions made about the bark characteristics. Collective research and collaboration on the methods for bark particle aerodynamic classification and aerodynamic treatment is suggested as a panel discussion topic.

BOILER GEOMETRY AND OPERATION

A Combustion Engineering VU-40 stoker boiler was modeled. Firing 100% hog fuel, the boiler occasionally experienced opacity problems. There was a pattern of erosion-related tube leaks operating at higher loads. The steam flow on hog fuel was close to design conditions, but had carbon loss even with high excess air. The CO levels were estimated to be high as well. A char recycle system was necessary to reduce fan erosion rates.

This 1975 contract furnace was a traditional 2-drum design with the upper drum centerline 25.3m (83 ft) above the stoker. Plan dimensions of the travelling grate stoker were 7.29m x 6.98m (23'- 11"wide by 22'-11"deep). The boiler was designed for 51.7 kg/s steam @ 441C and 5.86 MPa (410,000 lb./hr steam at 825°F and 850 psig) firing either oil or hog/oil fuels in combination. The maximum load on hog fuel was only 44.1 kg/s (350,000 lb./hr).

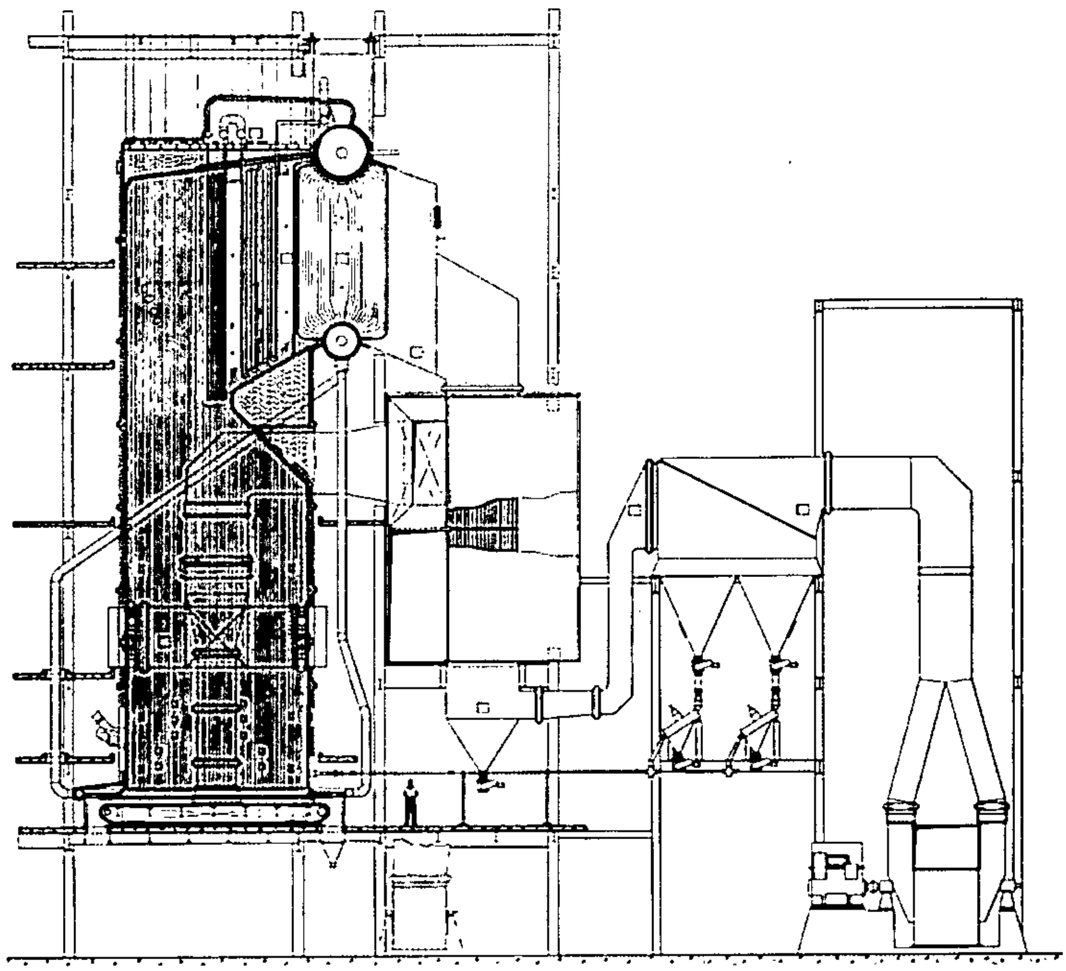

Fig. 1 Boiler Arrangement

Combustion air from the tubular air heater provided both undergrate and overfire air to an array of nozzles and burners. The travelling grate air was partitioned into four sections. Two separate ducts fed corner tangential windbox assemblies for OFA and support fuel, as well as a series of 20 sidewall OFA ports. Further, there was air supplied by a fan for the row of rear wall cinder reinjection nozzles. During baseline operations, all but the top level of sidewall OFA ports were off. The flow measurements indicated nearly 24% of the air from the airheater was admitted through the corner OFA ports and the large auxiliary fuel compartments. The cinder reinjection air levels were estimated. Calculated the total leakage rate was 13%, with significant infiltration around the stoker seals as well as other miscellaneous infiltration sources around the boiler. Without taking detailed measurements of all the fan flows, one might have assumed a lower percentage of infiltration air, stressing the need for detailed testing to obtain accurate model inputs.

The boiler arrangement and the resulting CFD mesh generated appears in Figures 1-2. This mesh includes all the important air sources to the boiler. Several grids were generated, one for the baseline air case, and others to represent alternate overfire air concepts. A relatively coarse grid of 220,000 cells was used, consisting of all hexahedral elements. This number was selected as a compromise between getting a fine resolution of the flow details and minimizing the computer time needed to complete the simulations. A relatively coarse mesh was used to start with, concentrating nodes near the air nozzles. The mesh could be refined by adaption as needed.

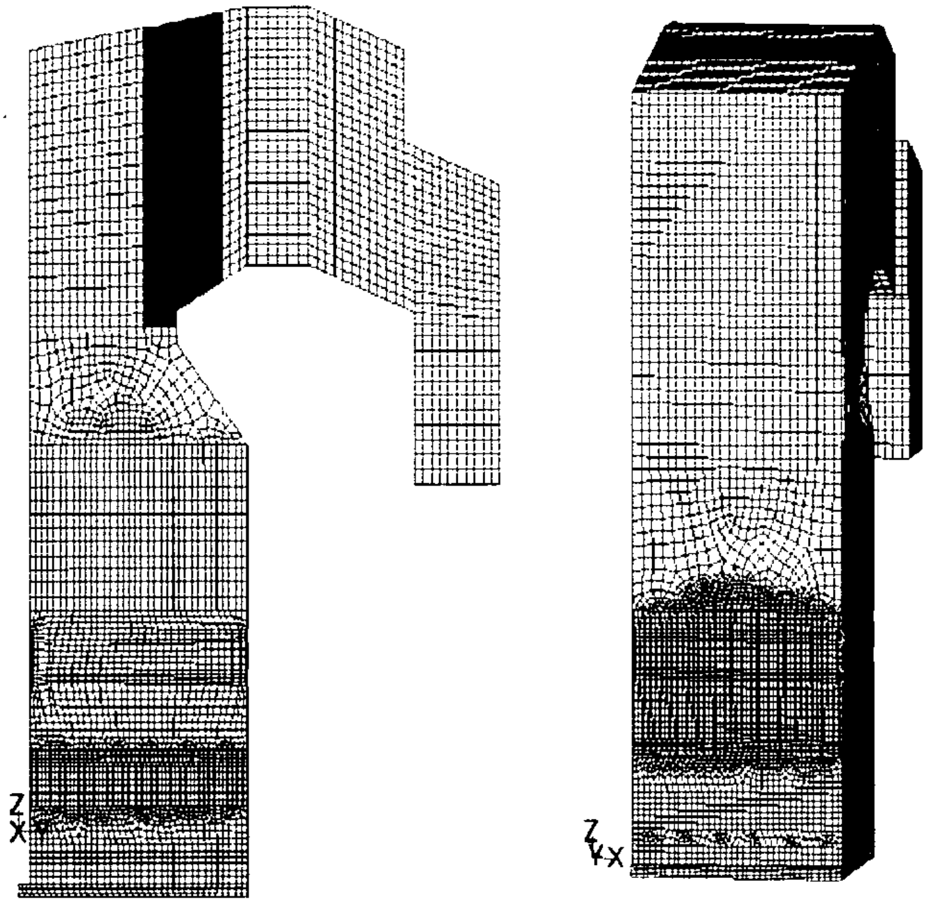

Fig. 2 CFD Mesh for Boiler

MODEL INPUTS

The CFD model inputs incorporate all the necessary elements associated with turbulent flow and combustion. For the heat transfer sections, bulk heat extraction rates were determined from the performance measurements and calculations. Heat extraction rates were applied to the superheaters, boiler bank, and economizer sections individually. Waterwall heat transfer coefficients and water side temperatures were prescribed in conjunction with wall emissivities. Both P-1 and Discrete Ordinates radiation methods were used, with radiation properties impacted by both gas composition and particle concentrations. Absorption/scattering by particles was included. The coupled calculations were run until reasonably steady state conditions were achieved along with an overall energy balance of within 1%.

The fuel and char reinjection streams and their associated burning mechanisms were defined. Reaction chemistry for the gas phase utilized the eddy-dissipation model, with mixing rates prescribed for a two-step reaction scheme. The bark fuel was analyzed to determine ultimate and proximate analysis. This fuel contained 48% moisture. Dry fuel was screened to determine particle size distributions. It was noted that 50% of the fuel mass was under 6.35mm (0.25 inch). Consideration was given to the fact that the as-fired fuel appears to be coarser than the analysis indicated is due to the clumping together of the sawdust with wetter bark. The particle shape factors of the injected fuel were also altered from spherical drag-coefficient settings, because their shapes deviated significantly from perfect spheres. For the fuel injection representation in the model, 8 particle size groups were defined and prescribed at each of the 5 distributors, with mass distribution to the different distributors weighted according to the actual feeder speeds used during the baseline test conditions. A non-uniform bell shaped feed distribution had been developed from experience to provide the best possible operation with the tangential air levels in service. This provided more fuel to the center of the stoker. Particles in the model follow a process of drying, devolatilization,

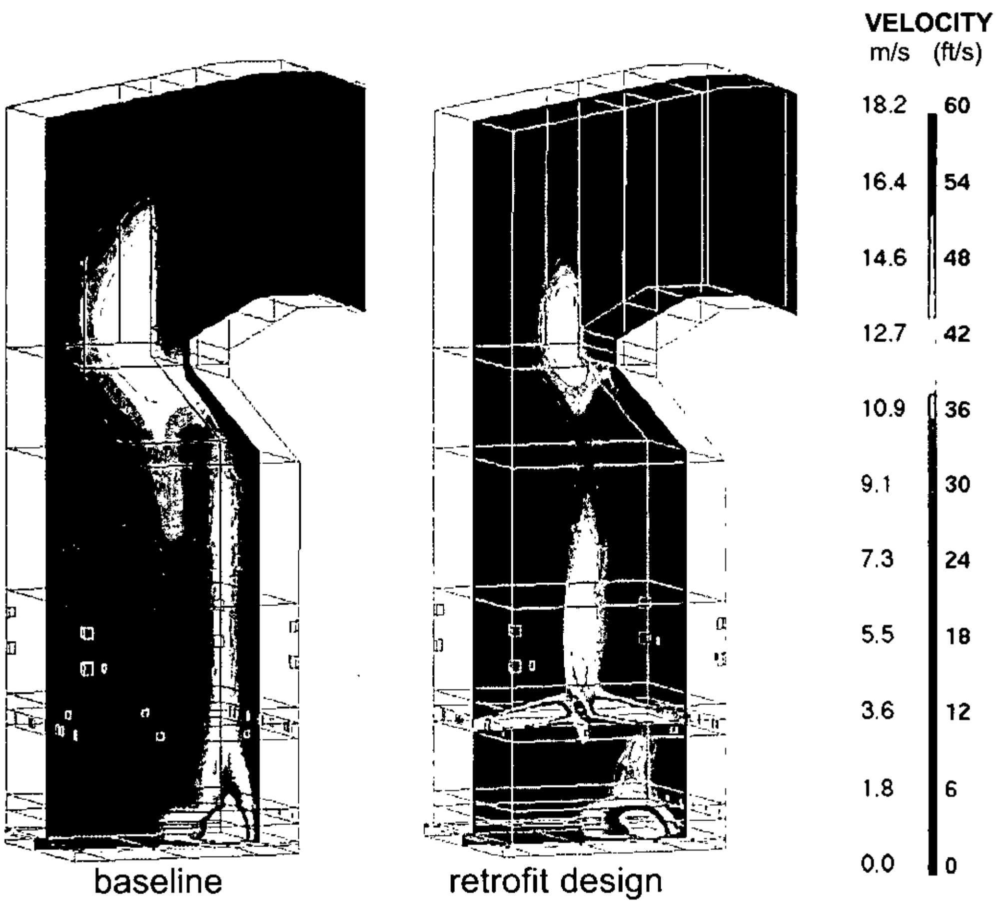

Fig. 3 Vertical velocity distribution

and surface-rate dependent char combustion. In addition to the bark, the char recycle flows were estimated and included distributed uniformly to each of the 8 nozzles based in the size distribution and composition of the recycle.

RESULTS

The baseline and installed new air system configuration are described in this section. In addition to the baseline conditions which was described, the new air system design incorporated the Horizontal Mixing Zone (HMZ)™ design technology. This design features large nozzles opposing small nozzles on the opposite wall in a partially interlaced fashion to control the penetration distance and establish high turbulence levels in the center zone. For this particular boiler, the overfire air nozzles were located on the front and rear walls in a 5 x 5 pattern. In conjunction with the retrofit, the stoker infiltration was eliminated by installation of a fabric filter seal. This allowed the air quantity to the new OFA level to meet design targets. Cooling air to the upper tangential air and fuel compartments were maintained for the retrofit condition modeled.

<u>Flow Distribution</u>
Gas velocity plots comparing velocity magnitude at the centerline of the boiler are shown in Fig. 3. The baseline case has a plume of gas that flows up the rear wall. The impact of the baseline sidewall and tangential OFA jets imparts a minor amount of swirl to the rising gases, which has little impact on the front to back flow profile. The new overfire design condition shows penetration of the jets to the center, with recirculation zones above and below this injection level. Instead of a rising plume of fuel against the rear wall, the channel is centralized, allowing the gases to mix thoroughly. An advantage of the new system configuration is the increased turbulence levels generated by the retrofit design. The interaction of the jets greatly increases the mixing rates and temperatures to provide faster drying of the fuel. Compared to the baseline system, 3-D surface plots of a constant turbulence level are illustrated in Fig. 4.

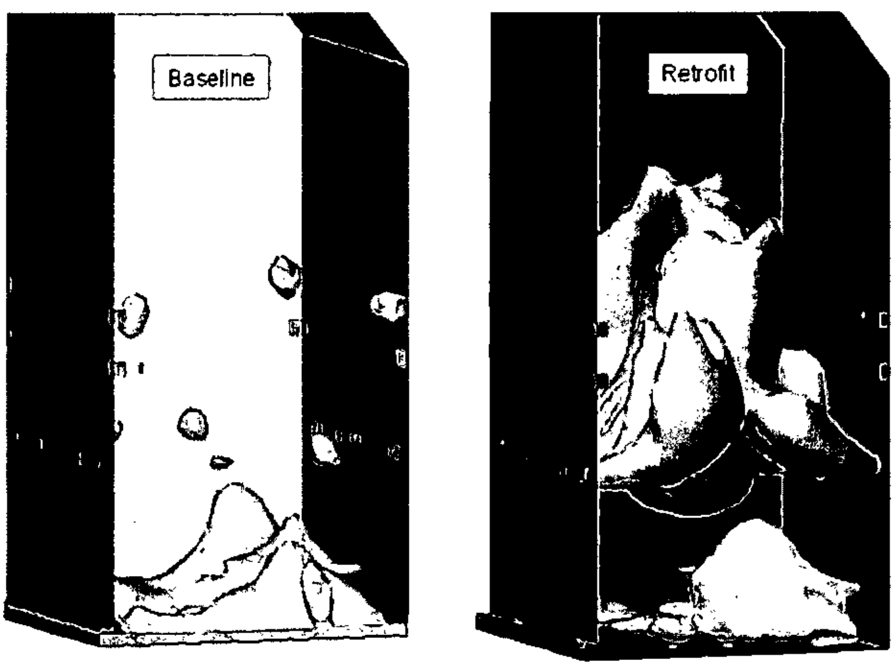

Fig. 4 Comparison of Isosurface of Turbulence

The improvements in mixing due to the overfire air system has a pronounced impact of the gas composition above the grate. The baseline system had a bypass stream of fuel rising up the rear wall without effective mixing with the other combustion products. The resulting gas flow distribution in the channel was low in Oxygen, increasing the unburned carbon levels. The retrofit design shows much more uniform O2 distribution as indicated in Fig. 5. In considering the history of erosion, we felt more comfortable with the front and rear wall placement rather than the sidewalls. While the mixing performance is similar, our various simulations showed that the velocity profile across the furnace entering the superheaters was flatter with the front and rear overfire air located on the front and rear walls as shown in Fig. 6. A more uniform side to side profile entering the superheaters also reduces the tendency for a temperature imbalance.

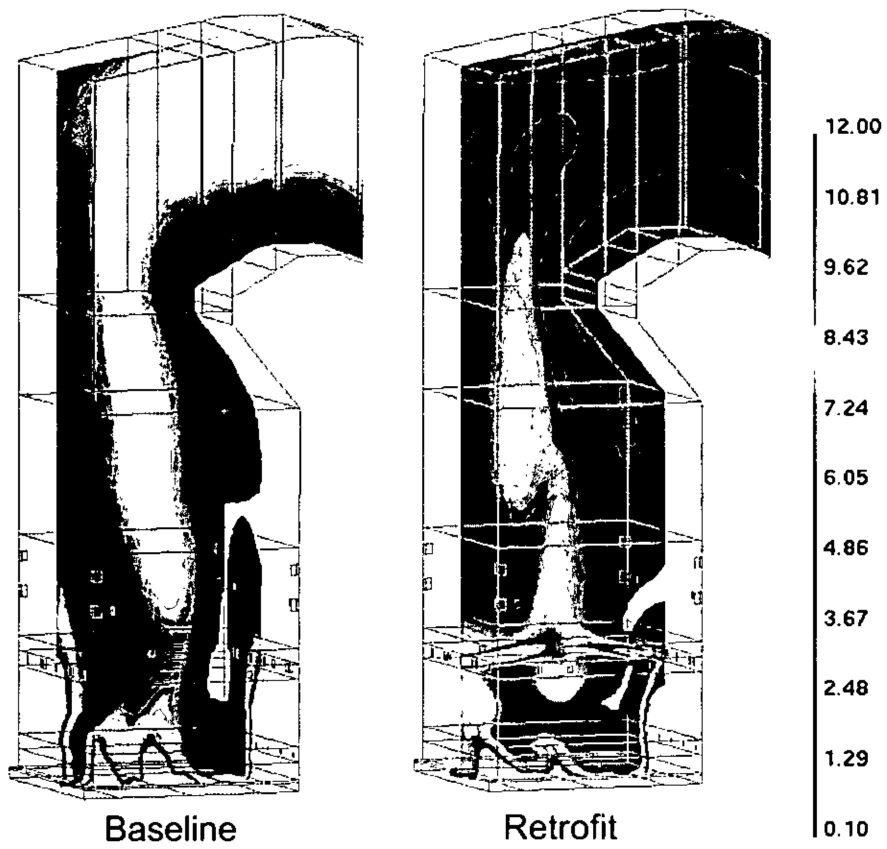

Fig. 5 Comparison of Oxygen distribution – %dry

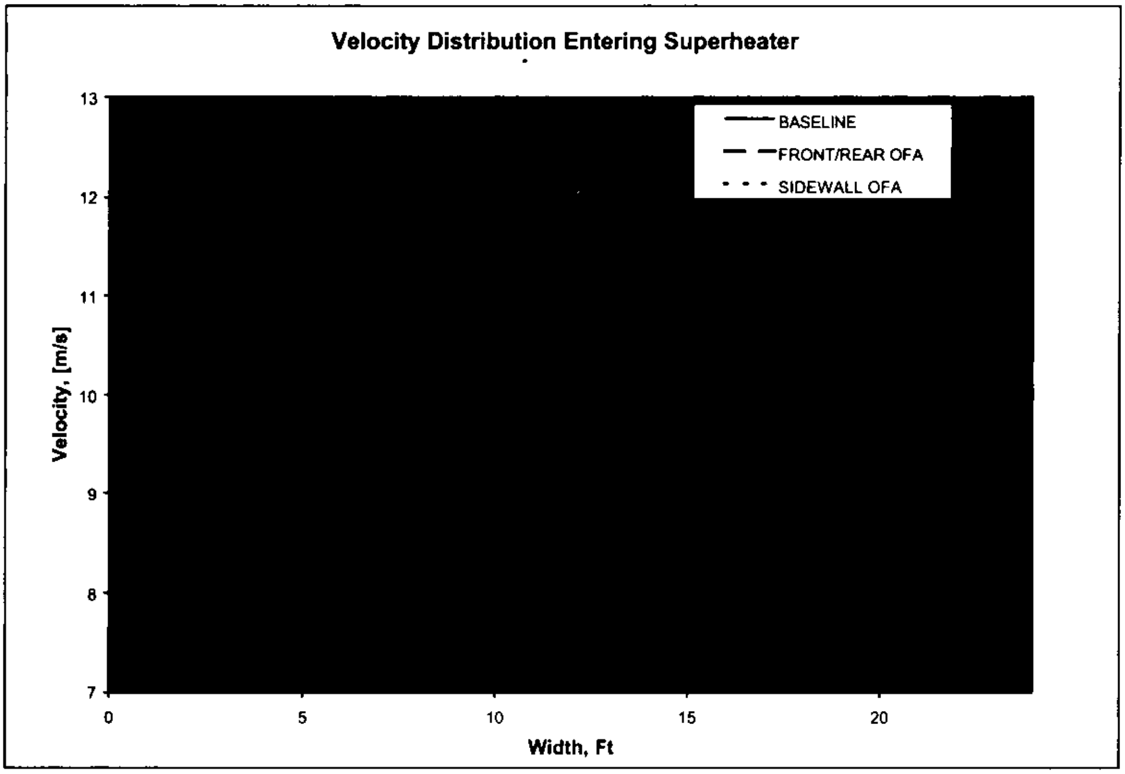

Fig. 6 Side to Side Velocity Profile Entering Superheater

Particle Burning Patterns

The burning patterns for the fuel injected from the distributors was studied carefully to better understand the differences in the two arrangements. The fuel system for this boiler has 5 mechanical wood fuel distributors located across the front wall. A distinctly different trajectory for the particles was found to exist between those burning in suspension and those that remain on the grate. The turbulent particle flight paths of small particles is compared for the baseline and retrofit arrangement in Fig. 7, colored by residence time. The path of the particles burning in suspension for the baseline case is smoother than those in the retrofit case which are subject to many jets. The dispersion and mean residence times for the particles is very sensitive to diameter and choice of drag coefficients. The largest contributions to the unburned fraction comes from particles in the middle diameter groups. Larger particles have residence times of several minutes and normally burn to completion. Clearly the models are a representation of the expected behavior. The sensitivity of the various particle trajectories is a subject of study. The results of the CFD model provide a useful indication, which is best supported by field measurements.

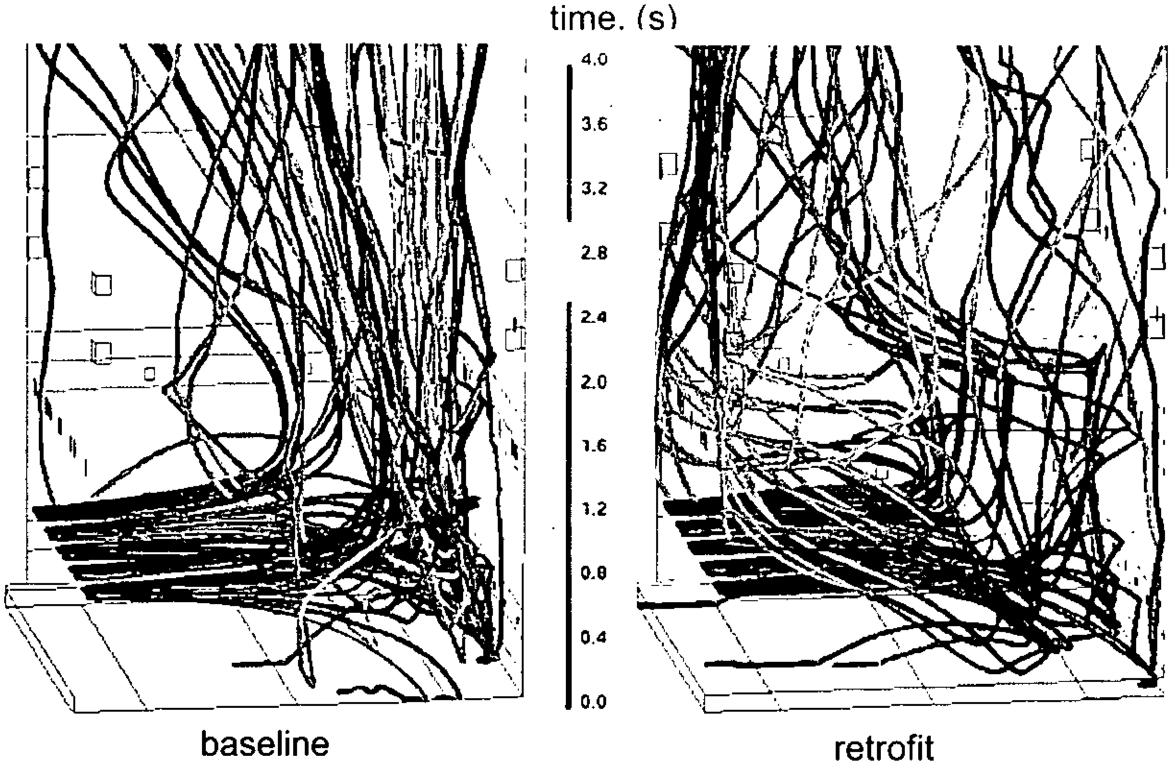

Fig 7 Comparison of Particle tracks colored by residence time.

BOILER TESTS vs. CFD MODELING

The CFD model was used to predict the performance of the boiler before and after the retrofit with the intention of validating the results upon completion of the modifications. Once the project was completed, a performance test was carried out on the boiler. The increase in boiler capacity achieved on biomass firing was significant. Prior to the upgrade the boiler was capable of only 35.3 kg/s (280,000 lb./hr) steam firing a high level moisture fuel. When the moisture level dropped the capacity achievable increased to 44.1 kg/s (350,000 lb./hr). At this load, the boiler suffered from high erosion and the boiler operation could not be maintained without tube failures. After the upgrade, the boiler biomass firing capability increased from 44.1 kg/s on high moisture fuel up to 60.5 kg/s (480,000 lb./hr) firing low moisture fuel. This represents a 25% minimum capacity increase. The CO levels after the retrofit were reduced from over 1000 PPM to 260 PPM.

A net reduction of 60% the pre-retrofit fly ash disposal rates as measured in truckloads was observed. The CFD model also showed about the same reduction in unburned carbon. Detailed isokinetic or other dust sampling methods were attempted but proved unfeasible in the mill operation. The longer term averaging of the ash measured as truckloads leaving for disposal was used as a long term measure of the reduction in carryover. Because the fuel contained a relatively constant 2% ash by analysis, it was surmised that the essentially all of the reduction in total ash disposal is unburned carbon. The economic analysis may in some cases might be significantly impacted by landfill costs. The performance changes are illustrated in Figure 8.

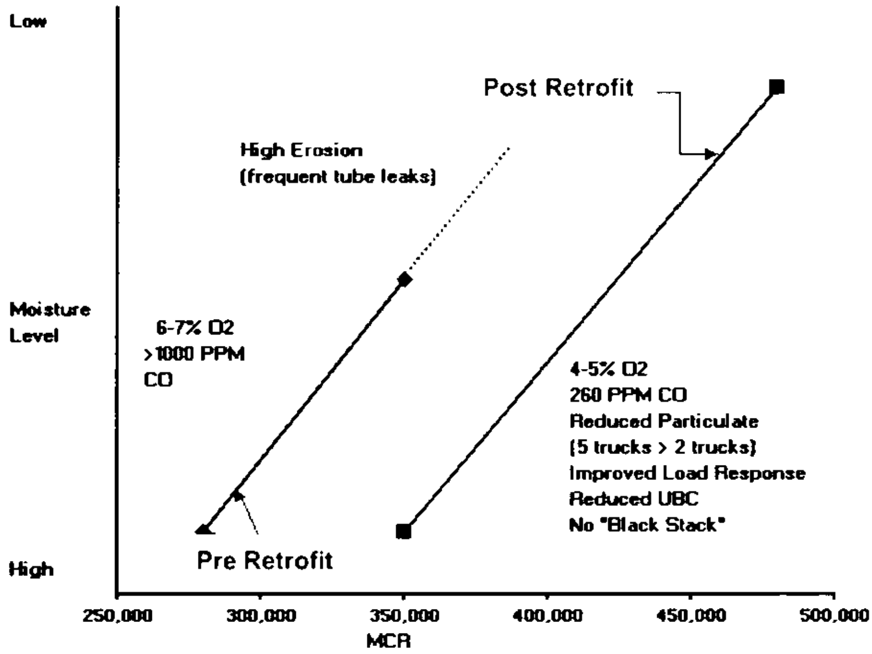

Fig. 8 Boiler Performance Summary

The CFD results for particle tracking (carryover) with the two cases are summarized in Table 1. The bulk reduction in solid wastes was about 60%. The CFD model predicted a similar reduction in the carbon in ash levels for the carryover material. The model also showed significant shift in the fate of the particles between the two cases, with the carryover levels reduced. The model showed that much less of the material was carried out, and remained on the grate. Quantification of the extent of burnout on the grate with the current model is still somewhat risky, due to many limitations described. However, the trends from the CFD model were shown to be generally supported by the bulk solid effluent reduction at the mill.

Table 1. CFD Predictions - Particle Tracking Summary

Ash Destinations:		Baseline Case	Retrofit Case
As Carryover - (to economizer)		48.0%	32.0%
As Bottom Ash - (stoker hopper)		52.0%	68.0%
Description of Carryover:			
Carbon	kg/hr	66	13
Ash (lb/hr)	kg/hr	409	241
Carbon in Ash	%	16.1%	5.4%
Description of Bottom Ash:			
Water	kg/hr	235.6	108
Volatiles	kg/hr	56.1	1
Carbon	kg/hr	388.7	224
Ash	kg/hr	306.6	475
Carbon in Ash	%	55.9%	32.0%
Total Solid Effluent:	kg/hr	1462	1061
Unburned %	%	51.05%	32.59%

FUTURE DEVELOPMENTS

There are several areas targeted for future development to improve simulation of the combustion processes within the biomass/bark boiler. These include:

- Improved physical representation of the combustion processes on the grate, such as piling and transient particle tracking methods which can include particle to particle interactions.
- More accurate simulation of the particle aerodynamics. A more accurate representation of the fuel clumps and how to represent them with the confines of the Lagrangian model as well as a means to measure the as-fired characteristics compared to using the dry sieve analysis is needed
- Better CO and NOx Predictions

CONCLUSIONS AND RECOMMENDATIONS

A CFD model study was performed in conjunction with a bark/biomass boiler retrofit project. This model was used to show relative performance for different combustion air system designs. This predictions indicated a significant improvement in bark burning performance, which was demonstrated by the retrofit. The improvements are due to the installation of an efficient overfire air system with other mechanical improvements to reduce leakage. A more uniform gas distribution was predicted as well, with a significant drop in CO and particulate emissions.

The test results indicate the overall biomass firing capability has increased 25% over the maximum current capability. This increase in combustion capacity is coupled with less excess air, reduced carbon loss, and reduced power consumption. These results are typical for the installation of the improved overfire air system. An additional benefit cited by the customer was the stability of the boiler and the ability to generate more steam firing wet fuel. The economic benefits of these contributions should also be considered when evaluating retrofit economics. Further projects have been reported previously [1,2]

Based on the success of the modeling, further work will be undertaken to quantify the effects of bark properties on boiler performance. The properties include the fuel moisture, the actual fuel size distribution entering the boiler, and how these clumps break-up during the in-flight transport and drying process. Collaborative efforts to develop standardized methods for measuring and describing this fuel in bark/biomass CFD simulations should be considered.

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