Georgia-Pacific

Palatka Pulp and Paper Operations
Consumer Products Division
P.O. Box 919
Palatka, FL 32178-0919
(386) 325-2001

RECEIVED
MAY 28 2009
BUREAU OF AIR REGULATION

May 22, 2009

Mr. Jeffery F. Koerner, Air Permitting North Section
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Palatka, Florida Mill
Facility ID No. 1070005
Combustion of Pulp Rejects in No. 4 Combination Boiler

Dear Mr. Koerner:

Georgia-Pacific Consumer Operations LLC (Georgia-Pacific) owns and operates an unbleached and bleached Kraft pulp and paper mill in Palatka, Putnam County, Florida (Palatka Mill). Georgia-Pacific respectfully requests authorization from the Florida Department of Environmental Protection (FL DEP) to burn pulp knots and rejects as an additional fuel in the No. 4 Combination Boiler (Emissions Unit ID 016), along with No. 6 fuel oil, on-specification used oil and wood/bark fuel. Georgia-Pacific requests the FL DEP to incorporate this activity by amending the previously issued PSD permit issued on September 26, 2008 (Air Permit No. PSD-FL-393; Project No. 1070005-045-AC). Once Georgia-Pacific converts the No. 4 Combination Boiler to burn natural gas in place of No. 6 fuel oil, as required to fulfill its exemption from the Regional Haze Rule, the pulp fiber reject material will only be burned with natural gas and/or wood/bark.

Project Description

The Palatka Mill's pulp mill produces knots and rejects during washing and screening operations in the brownstock washer area. Knots are pieces of uncooked wood that are removed from the brownstock pulp prior to the brownstock washing process. Rejects are shives or splinters that are removed by a screening operation after the brownstock washing process. Both knots and rejects (hereafter sometimes collectively referred to as "pulp rejects") consist of wood fiber that has not been completely broken down in the digestion process, and both contain a small amount of residual black liquor from the digestion process.

Historically, the pulp rejects were ground up and mixed into natural grades of unbleached paper products. Due to the economics of the paper business, the production of natural grade products has been greatly reduced and the facility currently does not have a reliable means of utilizing this biomass material. Therefore, the facility has had to dewater and dispose of it in the mill's on-site landfill.

Implementation of this proposed project would allow the mill to burn the pulp rejects in the No. 4 Combination Boiler instead of disposing of them in the landfill. Both materials have positive energy value (approximately 3,400 Btu/lb on an "as-fired" basis) that can be beneficially utilized by making process steam for the plant and offsetting the burning of fossil fuels. The pulp rejects would be mixed with the bark at a ratio of approximately 6 % (wt.), which is based on burning a maximum of 80 tons per day of pulp rejects along with a maximum 1,368 tons per day of bark. The combination of pulp rejects plus wood/bark fuel would not exceed the current annual heat input limitation for the No. 4 Combination Boiler of 4,042,127 million British thermal units (Btus) per year.

Residual Black Liquor

DEP has asked if the pulp rejects could be washed to remove residual black liquor prior to mixing with bark for burning in the combination boiler. Since the rejects from the screening operation have already been washed as the pulp is processed through the brownstock washers, additional washing would result in limited removal of contaminants due to the amount of washing already completed.

The knots are removed from the brownstock system prior to the washers. However, the screw press currently used to dewater the knots is sufficiently effective in minimizing the black liquor content, and thereby reducing the residual sulfur content of the knots, and any resulting sulfur dioxide generated when combusted in the No. 4 Combination Boiler.

The mill currently does not have the facilities to provide additional washing of the pulp rejects and doing so would require the installation of additional soak tanks and press operations for little added benefit.

Emissions Changes

Based on recent analyses conducted by the mill (see Attachment B), and information presented in Technical Bulletin No. 906 published by the National Council for Air and Stream Improvement (NCASI)(see Attachment C), Georgia-Pacific does not expect the combustion of these materials in the No. 4 Combination Boiler to increase the potential emission rate of any regulated criteria pollutant, compared to the current Title V Permit limits, except for sulfur dioxide (SO_2). Using an average sulfur content of 0.54 % and a maximum of 8,000 tons per year of knots and rejects, we expect potential SO_2 emissions to increase by a maximum of 90 tons per year above the current baseline actual emissions. This is a conservative estimate because in actual practice, the pulp reject material will replace an equivalent amount of wood/bark fuel on a Btu basis. The estimated increase of approximately 90 tons per year of SO_2 emissions from burning the new fuel will not trigger PSD for SO_2 since there are sufficient offsets in the netting analysis when incorporating the five-year contemporaneous emission changes, to keep the project from triggering PSD. The combustion of the pulp rejects is not expected to significantly change the emission rate of any hazardous air pollutants compared to combusting wood/bark fuel (see emission calculations in Attachment D). As discussed below under NSPS applicability, the Mill is not increasing its maximum permitted hourly emission rate.

Based on investigations performed by NCASI (See Attachment E-Special Report 09-02, March 2009), when bark is combusted in combination boilers with other sulfur-bearing fuels, a portion of the sulfur is retained by the alkali wood ash, thereby reducing the amount of SO_2 generated during the combustion process. Based on NCASI's special report, the amount of sulfur retained in the alkali wood ash depends on the amount of unburned carbon in the wood ash. The actual percent reduction of sulfur dioxide emissions due to retention of sulfur in the wood ash will vary greatly, depending upon boiler design characteristics (such as a stoker-fired boiler, fluidized bed boiler, etc.), the amount and type of sulfur-bearing fuel co-fired with bark, and specific operating conditions (such as temperature, residence time, moisture content of the fuel, etc.). However, based on test data presented in NCASI's special report, up to 70% reduction in expected SO_2 emissions has been reported for certain types of boilers and fuels fired.

Based on our knowledge of the physical and chemical characteristics of the pulp reject material, and information contained in NCASI Technical Bulletin No. 906, Section 10 and Table Nos. 10.1 and 10.2 (see Attachment C), we do not expect an appreciable impact on emissions of speciated organics, metals, dioxins/furans, and criteria pollutants (nitrogen oxides or NO_x, carbon monoxide or CO, particulate matter or PM, and volatile organic compounds or VOCs), except for SO_2 emissions as described above, compared to burning bark/wood.

While we are not taking credit for any sulfur retention in the wood ash and subsequent reduction of SO_2 emissions as part of the emissions analysis for the proposed project, we do expect that only about 30% of the projected SO_2 increase would actually be realized due to the retention effects described above.

Regulatory Applicability

PSD Applicability- FDEP issued a PSD permit for the No. 4 Combination Boiler on September 26, 2008 (Air Permit No. PSD-FL-393; Project No. 1070005-045-AC) to (1) upgrade the bark/wood delivery system and increase the maximum hourly heat input rate from 512.7 MM Btu/hr to 564 MM Btu/hr, and (2) convert the supplemental No. 6 fuel oil firing system to natural gas and permanently discontinue the use of No. 6 fuel oil and on-spec used oil. Based on a netting analysis including other contemporaneous projects, this project was subject to PSD preconstruction review for emissions of PM_{10}, NO_x, CO, and VOCs.

GP requests that FL DEP incorporate the addition of pulp rejects as an additional fuel for the No. 4 Combination Boiler as part of the PSD permit issued in September 2008. GP has updated the Netting Table that was submitted with the original (July 2006) PSD application to exclude all projects that are no longer part of the current 5-year contemporaneous period. This includes the Phase I Cluster Rule (MACT) pollution control project (implemented in 2002), the replacement of the No. 6 Package Boiler with the No. 7 Package Boiler (implemented in 2002), and the permanent shutdown of the No. 4 Power Boiler (implemented in 2003). The Phase II Cluster Rule (MACT) pollution control project to control high volume, low concentration (HVLC) gases has also been removed from the Netting Table since it primarily dealt with the control of TRS emissions from HVLC sources, which are not part of the emissions assessment for the proposed project (discussions with Mr. Bruce Mitchell of FL DEP in March 2009 support this procedure). Additionally, the PSD projects related to the No. 4 Lime Kiln, the No. 4 Recovery Boiler, and the Bark Handling System have been removed from the Netting Table since those activities are now complete. The projects remaining as part of the 5-year contemporaneous period in the Netting Table include the emission reductions applicable to the conversion from No. 6 fuel oil to natural gas in the No. 5 Power Boiler completed in March 2008, and the proposed project to add the pulp reject material as fuel to the No. 4 Combination Boiler. Based on the revised Netting Table, the addition of this material as an additional fuel for the No. 4 Combination Boiler only triggers PSD for CO emissions. None of the other regulated pollutants trigger PSD due to the emission reduction credits from the conversion of the No. 5 Power Boiler to natural gas.

NSPS Applicability-as part of the technical evaluation for the 2006 PSD Permit Application, NSPS Subpart Db was determined to be potentially applicable. In that determination, GP stated that PM emissions would be reduced by accepting a lower Title V Permit limit of 0.04 lb/MM Btu compared to a previous average PM emission rate of approximately 0.05 lb/MM Btu (based on stack testing data reviewed during 2001 trhough 2007). The addition of pulp fiber reject material as an additional fuel is not expected to change the NSPS Subpart Db determination for PM emissions as the material is expected to generate emissions similar to those when combusting bark. For NO_x emissions, GP requested the postponement of an NSPS determination until such time that the project to increase the bark firing rate in the boiler is implemented and GP can perform an Appendix C Determination of Emission Rate Change. Similar to PM emissions, GP expects NO_x emissions generated from the combustion of pulp rejects to be no different than when combusting bark, and therefore, we do not expect any increase in the maximum hourly NO_x emission rate.

During the interim period of time before No. 6 fuel oil is eliminated from the No. 4 Combination Boiler, the Mill will accept a short-term limitation of 2,600 gallons per hour on the amount of No. 6 fuel oil that can be combusted, to prevent any increase in the maximum SO_2 emission rate contained in the Title V Permit (see attached calculations in Attachment F). This will ensure that the addition of pulp rejects to the No. 4 Combination Boiler does not trigger NSPS Subpart Db for SO_2 emissions. The Mill will demonstrate compliance with this limitation by monitoring the No. 6 fuel oil flow rate. With this limit, there will not be an increase in the boiler's maximum permitted hourly emission rate.

The addition of pulp rejects as an additional fuel for the No. 4 Combination Boiler will not require the expenditure of any capital funds since the material will simply be transported from its point of generation at the pulp mill to the bark pile using mill vehicles. The pulp rejects will be mixed with wood/bark using a front-end loader which in turn places the fuel mixture onto the conveyor system that feeds into the No. 4 Combination Boiler fuel chutes. As a result, there will be no equipment changes to accommodate the combustion of the new fuel in the No. 4 Combination Boiler and the definition of "reconstruction" under the NSPS rules will not be triggered.

NESHAP Applicability-as part of the technical evaluation for the 2006 PSD Permit Application, the Boiler MACT rule (40 CFR 63, Subpart DDDDD) was discussed as an applicable rule with a compliance date of September 13, 2007. However, on June 8, 2007, the regulation was vacated by the U.S. Court of Appeals for the D.C. Circuit (effective when the Court issued its mandate on July 30, 2007), so this rule was not listed as an applicable requirement in the final PSD permit issued to the Mill in September 2008. EPA is currently working to re-promulgate the Boiler MACT rule in response to the vacatur/remand decision. EPA must propose a new rule by July 15, 2009 and finalize that rule a year later, by July 15, 2010. On January 12, 2009, in the absence of applicable guidance from EPA or FDEP, the Mill submitted a protective Part 1 "MACT hammer" application consistent with 40 CFR 63.52(a)(1) and (e) and 63.53. On March 30, 2009, the Mill submitted a protective Part 2 "MACT hammer" application proposing that, in the event FDEP decides to process case-by-case MACT determinations, it incorporate requirements for relevant emission points (including the No. 4 Combination Boiler) consistent with emission limitations, work practices, compliance options and monitoring requirements that would have applied under the vacated rule, 40 CFR Part 63, Subpart DDDDD (2004).

FDEP Rule Applicability-The No. 4 Combination Boiler is subject to several state rules, including 62-296.404, which regulates TRS emissions from boilers, and 62-296.410, which regulates PM emissions and opacity from carbonaceous fuel burning equipment. The combustion of pulp rejects will not trigger any newly applicable requirements pursuant to Rule Nos. 62-296.404 and 62-296.410.

Air Quality Effects

The dispersion modeling performed as part of the previously issued PSD permit for the No. 4 Combination Boiler included a PSD Class I and Class II significant impact determination, and a regional haze analysis. The results of the Class I significant impact analysis indicated the maximum predicted impacts for PM_{10} and NO_2 were less than the corresponding significant impact levels for either pollutant. The addition of pulp rejects as a fuel for the No. 4 Combination Boiler will not change this determination since we do not expect a change in PM_{10} or NO_2 emissions compared to burning wood/bark alone or the maximum hourly or daily SO_2 emission rate.

The results of the PSD Class II significant impact analysis for CO emissions were well below the corresponding PSD Class II significant impact level and no further analysis for CO was required. The addition of pulp rejects to the No. 4 Combination Boiler will not change this determination since we do not expect a change in CO emissions compared to burning wood/bark alone. The PSD Class II significant impact analysis as part of the previously issued PSD permit for the No. 4 Combination Boiler for PM_{10} and NO_2 indicated these pollutants to be significant. However, the maximum predicted impacts for these two pollutants were determined to be less than the allowable PSD Class II increments. Again, as stated above, the addition of pulp rejects to the No. 4 Combination Boiler will not change this determination since we do not expect a change in PM_{10} or NO_2 emissions compared to burning wood/bark alone.

The results of the regional haze analysis as part of the previously issued PSD permit for the No. 4 Combination Boiler indicated no significant visibility impact on any Class I area. To assure that the proposed addition of pulp rejects to the No. 4 Combination Boiler will not change the results of the prior Best Available Retrofit Technology (BART) analysis, the Mill completed an additional analysis for the BART exemption criteria. Attachment "G" presents the analysis and demonstrates that the facility still will not cause or contribute to any degradation in visibility as defined in the USEPA BART Guidance.

In summary, there is no reason to expect that the addition of pulp rejects to the No. 4 Combination Boiler as an additional fuel will cause, or significantly contribute to, a violation of any national Ambient Air Quality Standard or PSD increment.

Best Available Control Technology Analysis

The Best Available Control Technology (BACT) analysis for the previously submitted PSD application addressed the following pollutants: PM/PM_{10}, NO_x, CO, and VOCs. PSD was not triggered for SO_2 emissions, and therefore, a BACT analysis was not required for this pollutant. The combustion of pulp rejects in the No. 4 Combination Boiler is not expected to change the emission rates of PM/PM_{10}, NO_x, CO, and VOCs, therefore, the previously submitted and proposed BACT limits are not affected. The estimated increase of approximately 90 tons per year of SO_2 emissions from burning the new fuel will not trigger PSD for SO_2 since there are sufficient offsets in the netting analysis when incorporating the five-year contemporaneous emission changes, to keep the project from triggering PSD (see Netting Table in Attachment H). Therefore, a BACT analysis for SO_2 is not required.

Conclusion

In summary, the proposed project to add pulp rejects to the No. 4 Combination Boiler as an additional fuel will comply with all applicable state and federal air pollution regulations.

If there are any questions regarding this application, please do not hesitate to contact Mike Curtis at (386) 329-0918.

Sincerely,

Gary L. Frost
Vice President and Mill Manager
Georgia-Pacific LLC-Palatka Mill

GLF/wjg

Encl.

cc: Mike Curtis FL180
Ron Reynolds FL180
Wayne Galler GA030-09

Georgia-Pacific

Georgia-Pacific Consumer Products LLC Palatka Mill

BART EXEMPTION ANALYSIS UPDATE
FIBER REJECTS FUEL PROJECT
MAY 2009

CD on file

ATTACHMENT A

Department of
Environmental Protection
Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

Department of Environmental Protection

Division of Air Resource Management

RECEIVED
MAY 28 2009
BUREAU OF AIR REGULATION

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

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

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

Air Operation Permit – Use this form to apply for:

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Georgia-Pacific Consumer Operations LLC**
2. Site Name: **Palatka Mill**
3. Facility Identification Number: **1070005**
4. Facility Location...
   Street Address or Other Locator: **215 County Road 216**
   City: **Palatka** County: **Putnam** Zip Code: **32177**
5. Relocatable Facility? ☐ Yes ☒ No
6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Ron Reynolds, Environmental Engineer – Air Quality**
2. Application Contact Mailing Address...
   Organization/Firm: **Georgia-Pacific Consumer Operations LLC**
   Street Address: **P.O. Box 919**
   City: **Palatka** State: **FL** Zip Code: **32178-0919**
3. Application Contact Telephone Numbers...
   Telephone: **(386) 329-0967** ext. Fax: **(386) 328-0014**
4. Application Contact E-mail Address: **ron.reynolds@gapac.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 5/28/09	3. PSD Number (if applicable): 393A
2. Project Number(s): 1070005-062-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

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

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

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

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

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

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

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

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

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

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

Application Comment

GP is requesting authorization from the Florida Department of Environmental Protection (FL DEP) to burn pulp fiber reject material as an additional fuel -in the No. 4 Combination Boiler (Emissions Unit ID 016), along with natural gas and wood fuel. GP requests the FL DEP to incorporate this activity as part of the previously issued PSD permit issued on September 26, 2008 (Air Permit No. PSD-FL-393; Project No. 1070005-045-AC).

APPLICATION INFORMATION

Scope of Application

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

Application Processing Fee

Check one: ☐ Attached - Amount: $____________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1. Owner/Authorized Representative Name :
   Gary L. Frost Vice-President Operations

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

3. Owner/Authorized Representative Telephone Numbers...
   Telephone: **(386) 329-0063** ext. Fax: **(386) 312-1135**

4. Owner/Authorized Representative E-mail Address: **gary.frost@gapac.com**

5. Owner/Authorized Representative Statement:

   I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.

   Signature

   21 MAY 09
   Date

APPLICATION INFORMATION

Application Responsible Official Certification

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

1. Application Responsible Official Name:
   Gary L. Frost Vice-President Operations

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, CAIR source, or Hg Budget source.

3. Application Responsible Official Mailing Address...
   Organization/Firm: **Georgia-Pacific Consumer Operations LLC**
   Street Address: **P.O. Box 919**
   City: **Palatka** State: **FL** Zip Code: **32178**

4. Application Responsible Official Telephone Numbers...
   Telephone: **(386) 329-0063** ext. Fax: **(386) 312-1135**

5. Application Responsible Official E-mail Address: **gary.frost@gapac.com**

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

Professional Engineer Certification

1. Professional Engineer Name: **Mark Aguilar**
   Registration Number: **52248**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Georgia-Pacific LLC**
   Street Address: **133 Peachtree Street NE**
   City: **Atlanta** State: **GA** Zip Code: **30303**
3. Professional Engineer Telephone Numbers...
   Telephone: **(404) 652-4293** ext. Fax: **(404) 232-4310**
4. Professional Engineer E-mail Address: **mjaguila@gapac.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.

Mark J. Aguilar
Signature

5/6/09
Date

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **434.0** North (km) **3,283.4**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **29/41/0** 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:
Ron Reynolds, Environmental Engineer – Air Quality

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

3. Facility Contact Telephone Numbers:
Telephone: **(386) 329-0967** ext. Fax: **(386) 328-0014**

4. Facility Contact E-mail Address: **ron.reynolds@gapac.com**

Facility Primary Responsible Official

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

1. Facility Primary Responsible Official Name:
Gary L. Frost Vice-President Operations

2. Facility Primary Responsible Official Mailing Address...
Organization/Firm: **Georgia-Pacific Consumer Operations LLC**
Street Address: **P.O. Box 919**
City: **Palatka** State: **FL** Zip Code: **32178**

3. Facility Primary Responsible Official Telephone Numbers...
Telephone: **(386) 329-0063** ext. Fax: **(386) 312-1135**

4. Facility Primary Responsible Official E-mail Address: **gary.frost@gapac.com**

Facility Regulatory Classifications

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

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

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
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**
Pb (Lead)	**A**	**N**
SAM (Sulfuric Acid Mist)	**A**	**N**
H001 (Acetaldehyde)	**A**	**N**
H006 (Acrolein)	**A**	**N**
H017 (Benzene)	**A**	**N**
H038 (Chlorine)	**A**	**N**
H095 (Formaldehyde)	**A**	**N**
H104 (Hexane)	**A**	**N**
H106 (Hydrochloric Acid)	**A**	**N**
H115 (Methanol)	**A**	**N**
H113 (Manganese)	**A**	**N**
H128 (Methylene Chloride)	**A**	**N**
H169 Toluene)	**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's Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:
The Palatka Mill does not have any facility-wide or multi-unit emission caps.

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:________ ☒ Previously Submitted, Date: **07/2006**
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:________ ☒ Previously Submitted, Date: **07/2006**
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:________ ☒ Previously Submitted, Date: **07/2006**

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☐ Attached, Document ID:________ ☒ Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☐ Attached, Document ID:________
3. Rule Applicability Analysis: ☐ Attached, Document ID:________
4. List of Exempt Emissions Units: ☐ Attached, Document ID:________ ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification: ☐ Attached, Document ID:________ ☒ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☐ Attached, Document ID:________ ☒ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☐ Attached, Document ID:________ ☒ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☐ Attached, Document ID:________ ☒ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:________ ☒ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:________ ☒ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units: ☐ Attached, Document ID:__________ ☒ Not Applicable (no exempt units at facility) – **No exempt units as part of this permit application**

Additional Requirements for Title V Air Operation Permit Applications

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

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

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

1. Acid Rain Program Forms:

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

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

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

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

3. Hg Budget Part (DEP Form No. 62-210.900(1)(c)):
☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:_________
☒ Not Applicable (not a Hg Budget unit)

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
No. 4 Combination Boiler (EU016)

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

4. Emissions Unit Status Code: **A**	5. Commence Construction Date: **2009**	6. Initial Startup Date: **1966**	7. Emissions Unit Major Group SIC Code: **26**

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

☐ Acid Rain Unit

☐ CAIR Unit

☐ Hg Budget Unit

9. Package Unit:
Manufacturer: **Babcock &Wilcox** Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment: The No. 4 Combination Boiler with a centrifugal collector and an electrostatic precipitator in series to control particulate matter emissions. This boiler serves as a backup destruction device for non-condensable gases (NCGs) and condensate stripper off-gases from the sources required to be controlled by 40 CFR Part 63, Subpart S (MACT 1) and State TRS regulations. The primary destruction device is the Thermal Oxidizer (EU 037). When utilized in this mode, a spray tower pre-scrubber is used to remove sulfur from the batch (Batch Digesting system) streams and a separate, spray tower pre-scrubber is used to remove sulfur from the continuous (MEE System) streams prior to destruction in the boiler. NCGs from the Turpentine Condensing system and stripper off-gases (SOGs) from the Condensate Stripper System are vented directly to the boiler for destruction. The boiler is permitted to operate as the backup destruction device for a maximum uptime of 20 percent "which is equivalent to an annual maximum total of 548.7 tons of Sulfur Dioxide from the burning of NCGs and SOGs in the No. 4 Combination Boiler."

The boiler is permitted to combust a combination of bark and natural gas. The maximum bark firing rate is 59 tons per hour, or 1,416 tons per day, while the maximum natural gas firing rate is 0.427 million (MM) cubic feet per hour or 10.25 MM cubic feet per day. The Mill is proposing to combust a maximum of 80 tons per day or 8,000 tons per year of pulp fiber reject material in this boiler. The pulp fiber reject material will replace an equivalent amount of bark based on its heat content, which is estimated to be approximately 3,400 Btu/lb ("as-fired" basis).

Emissions Unit Control Equipment/Method: Control 1 of 2

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

Emissions Unit Control Equipment/Method: Control 2 of 2

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

Emissions Unit Control Equipment/Method: Control ___ of ___

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

Emissions Unit Control Equipment/Method: Control ___ of ___

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

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:
2. Maximum Production Rate:
3. Maximum Heat Input Rate: **564.0 million Btu/hr (bark, including pulp fiber reject material); 427.0 MM Btu/hr (Natural gas)**
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 (including pulp fiber reject material) only or in combination with natural gas. Maximum heat input rate shall not be exceeded as a 3-hour average. The maximum heat input rate on an annual basis is synthetically limited to 4,042,127 MM Btu/yr. Natural gas is also used as a start-up fuel.** **The mill's proposal to burn up to 8,000 tons per year of pulp fiber reject material in this boiler will not change the synthetic heat input limit.**

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: **515** °F	9. Actual Volumetric Flow Rate: **343,400** acfm	10. Water Vapor: **18.4** %
11. Maximum Dry Standard Flow Rate: **147,300** 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 engineering design information burning 100% bark.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **External Combustion Boilers: Industrial; Wood, bark and pulp fiber reject material**		
2. Source Classification Code (SCC): **1-02-009-02**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **57.0 ton/hr bark/wood** ***3.33 ton/hr pulp fiber* reject material**	5. Maximum Annual Rate: **419,779 tons bark-wood/yr** ***8,000 tons/yr pulp fiber* reject material**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **9.5 wood/bark; 6.8 pulp fiber**
10. Segment Comment: **Maximum hourly rate is based on maximum 3-hr average of 541.4 MM Btu/hr bark/wood (4,750 Btu/lb) and 22.6 MM Btu/hr pulp fiber reject material (3,389 Btu/lb).** **Bark/wood (hourly): 541.4.0 MM Btu/hr x 1 lb / 4,750 Btu x 1 ton / 2,000 lbs = 57.0 tons/hr** **Bark/wood (annual): 4,042,127 MM Btu/yr (total) – 54,224 MM Btu/yr (pulp fiber) = 3,987,903 MM Btu/yr, or 419,779 tons/yr; maximum pulp fiber reject material firing rate = 8,000 tons/yr.** **Pulp fiber reject material (hourly): 3.3 tons/hr x 2,000 lb/ton x 3,389 Btu/lb / 1.0 MM Btu = 22.6 MM Btu/hr** **Pulp fiber reject material(annual) = 8,000 ton/yr x 2,000 lb/ton x 3,389 Btu/lb / 1.0 MM Btu = 54,224 MM Btu/yr**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Natural Gas >100 MM Btu/hr**		
2. Source Classification Code (SCC): **1-02-006-01**	3. SCC Units: **Millions cubic feet burned**	
4. Maximum Hourly Rate: **0.427**	5. Maximum Annual Rate: **3,740.5 MM cubic feet**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,000**
10. Segment Comment: **Maximum hourly: 427.0 MM Btu/hr x 1 ft^3/1,000 Btu = 0.427 ft^3/hr** **Maximum annual: 3,740.5 MM ft^3/yr**		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

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:		

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
H001 (Acetaldehyde)			NS
H006 (Acrolein)			NS
H017 (Benzene)			NS
H038 (Chlorine)			NS
H095 (Formaldehyde)			NS
H104 (Hexane)			NS
H106 (Hydrochloric Acid)			NS
H115 (Methanol)			NS
H113 (Manganese)			NS
H128 (Methylene Chloride)			NS
H169 Toluene)			NS
HAPs (Total Hazardous Air Pollutants)			NS

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22.6** lb/hour **80.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.04 lb/MM Btu** Reference: **BACT Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Bark/wood/pulp fiber reject firing:
0.04 lb/MM Btu x 564.0 MM Btu/hr = 22.6 lb/hr
0.04 lb/MM Btu x 4,042,127 MM Btu/yr x 1 ton / 2,000 lb = 80.8 ton/yr

Nat. gas firing:
0.0076 lb/MM ft^3 x 0.427 MM ft^3/hr = 0.003 lb/hr
0.003 lb/hr x 8,760 hr/yr x 1 ton / 2,000 lb = 0.014 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MM Btu. PM emission rate from burning pulp fiber reject material assumed to be no greater than PM emission rate from burning bark/wood.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.04 lb/MM Btu**	4. Equivalent Allowable Emissions: **22.6** lb/hour **80.8** tons/year
5. Method of Compliance: **Annual stack test using EPA Method No. 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Proposed limit for bark/wood/pulp fiber reject firing**	

Allowable Emissions Allowable Emissions __ of ___

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

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.7** lb/hour **59.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **74% of PM** Reference: **AP-42, Table 1.6-1**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Bark/wood/pulp fiber reject firing:
Max. hourly = 22.6 lb/hr x 74% = 16.7 lb/hr
Max. annual = 80.8 ton/yr x 74% = 59.8 ton/yr

Nat. gas firing:
PM_{10} = 0.0076 lb/MM ft^3 x 0.427 MM ft^3/hr = 0.003 lb/hr
PM_{10} = 0.003 lb/hr x 8,760 hr/yr x 1 ton / 2,000 lb = 0.014 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MM Btu. PM_{10} emission rate from burning pulp fiber reject material assumed to be no greater than PM_{10} emission rate from burning bark/wood.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **85.9** lb/hour **137.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **AP-42, Table 1.6-2 for wood/bark**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Bark/wood (annual) = 4,042,127 MM Btu/yr (total) – 54,224 MM Btu/yr (pulp fiber) = 3,987,903 MM Btu/yr
<u>Bark/wood firing:</u>
Hourly = 0.025 lb/MM Btu x 541.4.0 MM Btu/hr (564 – 22.6 = 541.4) = 13.5 lb/hr
Annual = 0.025 lb/MM Btu x 3,987,903 MM Btu/yr x 1 ton / 2,000 lb = 49.9 ton/yr
<u>Pulp fiber reject material firing:</u>
Hourly = 0.5412 % S (“as fired” basis) x 3.33 ton/hr x 2,000 lb/ton x 2 lb SO_2/lb S = 72.1 lb/hr
Annual = 0.5412 % S (“as fired” basis) x 8,000 ton/yr x 2,000 lb/ton x 2 lb S/lb SO_2 x 1 ton / 2,000 lb = 86.6 ton/yr
<u>Nat. gas firing:</u>
SO_2 = 0.6 lb/MM ft^3 x 0.427 MM ft^3/hr = 0.3 lb/hr
SO_2 = 0.3 lb/hr x 8,760 hr/yr x 1 ton / 2,000 lb = 1.3 ton/yr
Total SO_2 (hourly) = 13.5 (bark) +72.1 (pulp fiber rejects) + 0.3 (gas) = 85.9 lb SO_2/hr
Total SO_2 (annual) = 49.9 (bark) +86.6 (pulp fiber rejects) + 1.3 (gas) = 137.8 ton SO_2/yr
Total SO_2 (proposed permit limits) = 85.9 lb/hr and 137.8 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MM Btu.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: **85.9** lb/hour **137.8** tons/year
5. Method of Compliance: **Annual stack test using EPA Method No. 6**	
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): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **NO$_x$**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **135.4** lb/hour **485.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.24 lb/MM Btu** Reference: **BACT Title V Permit Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

<u>Bark/wood/pulp fiber reject material firing:</u>
Emission factor for bark/wood/pulp fiber reject material = 0.24 lb/MM Btu
NO$_x$ (hourly) = 0.24 lb/MM Btu x 564.0 MM Btu/hr = 135.4 lb/hr
NO$_x$ (annual) = 0.24 lb/MM Btu x 4,042,127 MM Btu/yr x 1 ton / 2,000 lb = 485.1 ton/yr

<u>Natural Gas Firing:</u>
Emission factor for natural gas = 0.15 lb/MM Btu
NO$_x$ (hourly) = 0.15 lb/MM Btu x 427.0 MM Btu/hr = 64.1 lb/hr
NO$_x$ (annual) = 64.1 lb/hr x 8,760 hr/yr x 1 ton / 2,000 lb = 280.8 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MM Btu. NO$_x$ emission rate from burning pulp fiber reject material assumed to be no greater than NO$_x$ emission rate from burning bark/wood.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.24 lb/MM Btu for bark/wood** **0.15 lb/MM Btu for natural gas**	4. Equivalent Allowable Emissions: **135.4** lb/hour (bark) **485.1** tons/year (bark) **64.1** lb/hour (gas) **280.8** tons/year (gas)
5. Method of Compliance: **Annual stack test using EPA Method No. 7 or 7E**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

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

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **282.0** lb/hour **1,010.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.5 lb/MM Btu** Reference: **BACT Title V Permit Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Bark/wood/pulp fiber reject firing:
Emission factor for bark/wood/pulp fiber reject material = 0.5 lb/MM Btu-based on over-fire air system

CO (hourly) = 0.5 lb/MM Btu x 564.0 MM Btu/hr = 282.0 lb/hr
CO (annual) = 0.5 lb/MM Btu x 4,042,127 MM Btu/yr x 1 ton / 2,000 lb = 1,010.5 ton/yr

CO emissions from natural gas firing will be lower than when firing bark since the heat input value for gas firing is 427 MM Btu/hr compared to 564 MM Btu/hr for bark, and the emission factor is the same, or 0.5 lb/MM Btu.

11. Potential, Fugitive, and Actual Emissions Comment:
Maximum annual emissions based on synthetic limit for heat input of 4,042,127 MM Btu/yr. CO emission factor is based on BACT permit limit using over-fire air system and low-NO_x burners for natural gas firing. CO emission rate from burning pulp fiber reject material assumed to be no greater than CO emission rate from burning bark/wood.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.5 lb/MM Btu**	4. Equivalent Allowable Emissions: **282.0** lb/hour **1,010.5** tons/year
5. Method of Compliance: **Annual stack test using EPA Method No. 10**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

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

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.3** lb/hour **40.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.02 lb/MM Btu** Reference: **BACT Title V Permit Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Bark/wood/pulp fiber reject material firing:

Emission factor for bark/wood/pulp fiber reject material = 0.02 lb/MM Btu
VOC (hourly) = 0.02 lb/MM Btu x 564.0 MM Btu/hr = 11.3 lb/hr
VOC (annual) = 0.02 lb/MM Btu x 4,042,127 MM Btu/yr x 1 ton / 2,000 lb = 40.4 ton/yr

Natural Gas Firing:

Emission factor for gas = 5.5 lb/MM ft^3
VOC (hourly) = 5.5 lb/MM ft^3 x 0.427 MM ft^3/hr = 2.35 lb/hr
VOC (annual) = 2.35 lb/hr x 8,760 hr/yr x 1 ton / 2,000 lb = 10.3 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MM Btu. VOC emission rate from burning pulp fiber reject material assumed to be no greater than VOC emission rate from burning bark/wood.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.02 lb/MM Btu**	4. Equivalent Allowable Emissions: **11.3** lb/hour **40.4** tons/year
5. Method of Compliance: **Annual stack test using EPA Method No. 25a**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

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

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.03** lb/hour **0.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **4.8E-05 lb/MM Btu (bark/wood); 5.0E-04 lb/MM ft^3 (gas)** Reference: **AP-42 Table 1.6-4 (bark); AP-42 Table 1.4-2 (gas)**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Bark/wood/pulp fiber reject material firing:
Emission factor for bark/wood = 4.8E-05 lb/MM Btu
Pb (hourly) = 4.8E-05 lb/MM Btu x 564.0 MM Btu/hr = 0.03 lb/hr
Pb (annual) = 4.8E-05 lb/MM Btu x 4,042,127 MM Btu/yr x 1 ton / 2,000 lb = 0.1 ton/yr

Natural Gas Firing:
Emission factor for gas = 5.0E-04 lb/MM ft^3
Pb (hourly) = 5.0E-04 lb/MM ft^3 x 0.427 MM ft^3/hr = 2.1E-04 lb/hr
Pb (annual) = 2.1E-04 lb/hr x 8,760 hr/yr x 1 ton / 2,000 lb = 9.2^{E}-04 ton/yr

Additional Pb from pulp fiber reject material = none-see attached analysis

Total Pb (proposed permit limit) = 0.03 lb/hr and 0.1 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum annual emissions based on synthetic limit for heat input of 4,042,127 MM Btu/yr. Analysis of pulp fiber reject material for lead indicated non-detectable levels.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions __ of ___

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

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **SAM (sulfuric acid mist)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.8** lb/hour **6.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Assumed **SAM = 4.4% of SO_2 emissions**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Sulfuric Acid Mist (SAM) emissions for fuel oil-AP-42, Section 1.3, Table 1.3-1 Emission factor for SO_3 = 5.7S lb/M gal. This is equivalent to 5.7/157 or 3.63% of SO_2 emission rate. Convert to SAM emission rate by multiplying ratio of molecular weights, 98 for SAM/80 for SO_3 = 1.225 x 3.63% = 4.4% of SO_2 emission rate. Assuming that SAM emissions from bark and pulp fiber rejects would be generated similar to fuel oil combustion, or 4.4%

SAM (hourly) = 0.044 x 85.6 lb SO_2/hr = 3.8 lb SAM/hr
SAM (annual) = 0.044 x 136.5 ton SO_2/yr = 6.0 ton SAM/yr

There are no SAM emissions generated when firing natural gas

11. Potential, Fugitive, and Actual Emissions Comment:
Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 4,042,127 MM Btu.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Acetaldehyde**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.45** lb/hour **1.65** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **8.3E-04 lb/MM Btu** Reference: **AP-42, Table 1.6-3**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Bark/wood/pulp fiber reject material firing:

lb/hr = 8.3E-04 lb/MM Btu x 541.4 MM Btu/hr = 0.45 lb/hr
ton/yr = 8.3E-04 lb/MM Btu x 3,987,903 MM Btu/yr x 1 ton / 2,000 lb = 1.65 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 3,987,903 MM Btu for bark firing when mixed with pulp fiber reject material.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Acrolein**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.2** lb/hour **8.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **4.0E-03 lb/MM Btu** Reference: **AP-42, Table 1.6-3**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Bark/wood/pulp fiber reject material firing:
lb/hr = 4.0E-03 lb/MM Btu x 541.4 MM Btu/hr = 2.2 lb/hr
ton/yr = 4.0E-03 lb/MM Btu x 3,987,903 MM Btu/yr x 1 ton / 2,000 lb = 8.0 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 3,987,903 MM Btu for bark firing when mixed with pulp fiber reject material.

EMISSIONS UNIT INFORMATION
Section [1] of [1]

POLLUTANT DETAIL INFORMATION
Page [20] of [40]
Acrolein

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Benzene**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.3** lb/hour **8.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **4.2E-03 lb/MM Btu (bark/wood/pulp); 2.1E-03 lb/MM ft^3 (gas)** Reference: **AP-42, Table 1.6-3(bark/wood/pulp); AP-42, Table 1.4-3**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Bark/wood/pulp fiber reject material firing:
lb/hr = 4.2E-03 lb/MM Btu x 541.4 MM Btu/hr = 2.3 lb/hr
ton/yr = 4.2E-03 lb/MM Btu x 3,987,903 MM Btu/yr x 1 ton / 2,000 lb = 8.4 ton/yr

Natural gas firing :
Benzene (hourly) = 2.1E-03 lb/MM ft^3 x 0.427 MM ft^3/hr = 9.0E-04 lb/hr
Benzene (annual) = 9.0E-04 lb/hr x 8,760 hr/yr x 1 ton / 2,000 lb = 3.9E-03 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 3,987,903 MM Btu for bark firing when mixed with pulp fiber reject material.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **Chlorine**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.43** lb/hour **1.6** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **7.9E-04 lb/MM Btu** Reference: **AP-42, Table 1.6-3**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

<u>Bark/wood/pulp fiber reject material firing:</u>
lb/hr = 7.9E-04 lb/MM Btu x 541.4 MM Btu/hr = 0.43 lb/hr
ton/yr = 7.9E-04 lb/MM Btu x 3,987,903 MM Btu/yr x 1 ton / 2,000 lb = 1.6 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 3,987,903 MM Btu for bark firing when mixed with pulp fiber reject material.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Formaldehyde**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.4** lb/hour **8.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **4.4E-03 lb/MM Btu (Bark/wood/pulp fiber); 7.5E-02 (gas)** Reference: **AP-42, Table 1.6-3 (Bark/wood/pulp fiber); AP-42, Table 1.4-3 (gas)**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Bark/wood/pulp fiber reject material firing:
lb/hr = 4.4E-03 lb/MM Btu x 541.4 MM Btu/hr = 2.4 lb/hr
ton/yr = 4.4E-03 lb/MM Btu x 3,987,903 MM Btu/yr x 1 ton / 2,000 lb = 8.8 ton/yr

Natural gas firing :
Formaldehyde (hourly) = 7.5E-02 lb/MM ft^3 x 0.427 MM ft^3/hr = 0.032 lb/hr
Formaldehyde (annual) = 0.032 lb/hr x 8,760 hr/yr x 1 ton / 2,000 lb = 0.14 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 3,987,903 MM Btu for bark firing when mixed with pulp fiber reject material.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **Hexane**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.16** lb/hour **0.58** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2.9E-04 lb/MM Btu (wood, bark); 1.8 lb/MM ft^3 (nat. gas)** Reference: **NCASI, TB # 858, Table 20A (wood, bark); AP-42, Table 1.4-3**	7. Emissions Method Code: **5 (wood, bark);** **3 (nat. gas)**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

<u>Wood/bark:</u>
lb/hr = 2.9E-04 lb/MM Btu x 541.4 MM Btu/hr = 0.16 lb/hr
ton/yr = 2.9E-04 lb/MM Btu x 3,987,903 MM Btu/yr x 1 ton / 2,000 lb = 0.58 ton/yr

<u>Natural gas :</u>
lb/hr = 1.8 lb/MM ft^3 x 0.427 MM ft^3/hr = 0.77 lb/hr
ton/yr = 0.77 lb/hr x 8,760 hr/yr x 1 ton / 2,000 lb = 3.4 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 3,987,903 MM Btu for bark firing when mixed with pulp fiber reject material.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Hydrochloric Acid**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.9** lb/hour **39.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.019 lb/MM Btu (wood/bark); 0.0239% (wt.) pulp fiber reject material** Reference: **AP-42, Table 1.6-3 (wood/bark); site specific analysis (pulp fiber reject material)**	7. Emissions Method Code: **3 (wood/bark)** **5 (pulp fiber)**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Wood/bark:
lb/hr = 0.019 lb/MM Btu x 541.4 MM Btu/hr = 10.3 lb/hr
ton/yr = 0.019 lb/MM Btu x 3,987,903 MM Btu/yr x 1 ton / 2,000 lb =37.9 ton/yr

Pulp fiber reject material:
lb/hr = 0.000239 (wt. fraction) x 6,600 lb/hr = 1.6 lb/hr
ton/yr = 0.000239 (wt. fraction) x (8,000 ton/yr x 2,000 lb/ton) x 1 ton / 2,000 lb = 1.9 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 3,987,903 MM Btu for bark firing when mixed with pulp fiber reject material.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Manganese**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **0.87** lb/hour **3.2** tons/year

4. Synthetically Limited? ☒ Yes ☐ No

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

6. Emission Factor: **1.6E-03 lb/MM Btu (wood/bark); 1.3E-04 lb/MM Btu pulp fiber reject material ; 3.8E-04 lb/MM ft^3 (gas)**
Reference: **AP-42, Table 1.6-4 (wood/bark); NCASI TB # 906, Table 10.2 (pulp fiber material); AP-42, Table 1.4-4 (gas)**

7. Emissions Method Code: **3 (wood/bark)** **5 (pulp fiber)**

8.a. Baseline Actual Emissions (if required): tons/year

8.b. Baseline 24-month Period: From: To:

9.a. Projected Actual Emissions (if required): tons/year

9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Wood/bark:
lb/hr = 1.6E-03 lb/MM Btu x 541.4 MM Btu/hr = 0.87 lb/hr
ton/yr = 1.6E-03 lb/MM Btu x 3,987,903 MM Btu/yr x 1 ton / 2,000 lb = 3.2 ton/yr

Pulp fiber reject material:
lb/hr = 1.3E-04 lb/MM Btu x 22.4 MM Btu/hr = 0.003 lb/hr
ton/yr = 1.3E-04 lb/MM Btu x 54,224 MM Btu/yr x 1 ton / 2,000 lb = 0.0035 ton/yr

Natural Gas firing:
lb/hr = 3.8E-04 lb/MM ft^3 x 0.427 MM ft^3/hr = 1.6E-04 lb/hr
ton/yr = 1.6E-04 lb/hr x 8,760 hr/yr x 1 ton / 2,000 lb = 7.1E-04 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 3,987,903 MM Btu for bark firing when mixed with pulp fiber reject material.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **Methanol**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.47** lb/hour **1.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2.9E-04 lb/MM Btu** Reference: **NCASI, TB # 858, Table 20A**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

<u>Bark/wood/pulp fiber reject material firing:</u>
lb/hr = 8.6E-04 lb/MM Btu x 541.4 MM Btu/hr = 0.47 lb/hr
ton/yr = 8.6E-04 lb/MM Btu x 3,987,903 MM Btu/yr x 1 ton / 2,000 lb = 1.7 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 3,987,903 MM Btu for bark firing when mixed with pulp fiber reject material.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Methylene Chloride**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.19** lb/hour **0.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **3.5E-04 lb/MM Btu** Reference: **AP-42, Table 1.6-3**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

<u>Bark/wood/pulp fiber reject material firing:</u>
lb/hr = 3.5E-04 lb/MM Btu x 541.4 MM Btu/hr = 0.19 lb/hr
ton/yr = 3.5E-04 lb/MM Btu x 3,987,903 MM Btu/yr x 1 ton / 2,000 lb = 0.7 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 3,987,903 MM Btu for bark firing when mixed with pulp fiber reject material.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Toluene**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **0.5** lb/hour **1.8** tons/year

4. Synthetically Limited? ☒ Yes ☐ No

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

6. Emission Factor: **9.2E-04 lb/MM Btu (bark/wood); 3.4E-03 (gas)**
Reference: **AP-42, Table 1.6-3 (bark/wood); AP-42, Table 1.4-3 (gas)**

7. Emissions Method Code: **3**

8.a. Baseline Actual Emissions (if required): tons/year

8.b. Baseline 24-month Period: From: To:

9.a. Projected Actual Emissions (if required): tons/year

9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Bark/wood/pulp fiber reject material firing:
lb/hr = 9.2E-04 lb/MM Btu x 541.4 MM Btu/hr = 0.5 lb/hr
ton/yr = 9.2E-04 lb/MM Btu x 3,987,903 MM Btu/yr x 1 ton / 2,000 lb = 1.8 ton/yr

Natural Gas firing:
lb/hr = 3.4E-03 lb/MM ft^3 x 0.427 MM ft^3/hr = 1.5E-03 lb/hr
ton/yr = 1.5E-03 lb/hr x 8,760 hr/yr x 1 ton / 2,000 lb = 6.4E-03 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 3,987,903 MM Btu for bark firing when mixed with pulp fiber reject material.

Toluene

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Total HAPs**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22.3** lb/hour **82.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **3.9E-02 lb/MM Btu (wood/bark); 7.6E-04 lb/MM Btu pulp fiber reject material ; 1.89 lb/MM ft^3 (gas)** Reference: **AP-42, Table 1.6-4 (wood/bark); NCASI TB # 906, Table 10.2; AP-42, Table Nos. 1.4-3 and 1.4-4 (gas)**	7. Emissions Method Code: **3 (wood/bark)** **5 (pulp fiber)**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: 5 years 10 years

10. Calculation of Emissions:

Wood/bark:
lb/hr = 3.97E-02 lb/MM Btu x 541.4 MM Btu/hr = 21.5 lb/hr
ton/yr = 3.97E-02 lb/MM Btu x 3,987,903 MM Btu/yr x 1 ton / 2,000 lb = 79.2 ton/yr

Pulp fiber reject material:
lb/hr = 0.07 lb/MM Btu x 22.4 MM Btu/hr = 1.6 lb/hr
ton/yr = 0.07 lb/MM Btu x 54,224 MM Btu/yr x 1 ton / 2,000 lb = 1.9 ton/yr

Natural Gas:
lb/hr = 1.89 lb/MM ft^3 x 0.427 MM ft^3/hr = 0.8 lb/hr
ton/yr = 0.8 lb/hr x 8,760 hr/yr x 1 ton / 2,000 lb = 3.5 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum emissions based on bark/wood/pulp fiber reject firing. Emissions are synthetically limited due to annual heat input limit of 3,987,903 MM Btu for bark firing when mixed with pulp fiber reject material.

Total HAPs

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Emissions reflect HVLC combustion (Permit No. 1070005-024-AC)	

Allowable Emissions Allowable Emissions __ of ___

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **Annual testing using EPA Reference Method 9**	
5. Visible Emissions Comment:	

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_X**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Not yet determined** Model Number: **N/A**	Serial Number: **N/A**
5. Installation Date: **Not yet installed**	6. Performance Specification Test Date: **N/A**

7. Continuous Monitor Comment: **A NO_x CEMS will be required once the bark upgrade project is implemented. The CEMS unit has not yet been selected.**

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **N/A**	2. Pollutant(s): **CO**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information. Manufacturer: **Not yet determined** Model Number:	Serial Number:
5. Installation Date: **Not yet installed**	6. Performance Specification Test Date: **N/A**

7. Continuous Monitor Comment: **A CO CEMS will be required once the bark upgrade project is implemented. The CEMS unit has not yet been selected.**

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: _________ ☒ Previously Submitted, Date **07/2006**

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: **Attachment A** ☐ Previously Submitted, Date **N/A**

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: **N/A** ☐ Previously Submitted, Date **N/A**

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 **11/2002**
☐ 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: **N/A** ☐ Previously Submitted, Date **N/A**
☐ Not Applicable

6. Compliance Demonstration Reports/Records:
☐ Attached, Document ID: _________
Test Date(s)/Pollutant(s) Tested: ____________________
☒ Previously Submitted, Date: **Annual submission of compliance certifications**
Test Date(s)/Pollutant(s) Tested: ____________________
☐ To be Submitted, Date (if known): _________
Test Date(s)/Pollutant(s) Tested: ____________________
☐ Not Applicable

Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
☐ Attached, Document ID: _________ ☒ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

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

Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

ATTACHMENT B

ANALYSIS OF PULP FIBER REJECT MATERIAL

Georgia-Pacific
Neenah Technical Center
Analytical Research Laboratory
1915 Marathon Avenue, P.O. 899
Neenah, WI 54957-0899

COMPANY CONFIDENTIAL

DATE: January 27, 2009

TO: ADEL KASSEBI - PALATKA

cc: Kacee Des Jarlais (NTC)
Bobby Manzoor (ATL)

FROM: BRIAN HAMMES - NTC

SUBJECT: Pulping Rejects and Knots dated 01/12/2009

INTRODUCTION

Two pulp rejects/knots samples were submitted for testing to provide data for a permit for burning this material. Samples labeled 1 and 2 were taken at 11:30 AM and 11:45 on 12/15/08, respectfully.

RESULTS

Table 1. Results for testing of pulp reject samples from the Palatka Mill[a,b]

Sample	#1	#2
Moisture, %	56.25	55.66
Ash, %	18.56	16.28
Heating Value, BTU/lb	7,650	7,753
Chloride ion, ppm	577	479
P as PO_4^{-3} ion, ppm	328	338
S as SO_4^{-2} ion, ppm	37,000	36,700
Na ion, ppm	56,400	51,900
K ion, ppm	3,310	3,140
Ca ion, ppm	3,200	1,460
Mg ion, ppm	433	341
Al ion, ppm	16	53
Fe ion, ppm	11	20
Mn ion, ppm	31	18
Ba ion, ppm	11	<10
Cr ion, ppm	N.D.	N.D.
Pb ion, ppm	N.D.	N.D.
Si as SiO_2, ppm	142	167

[a]The elemental analyses and heating values are reported on the oven-dried basis. [b]N.D. – Not Detected

EXPERIMENTAL

Moisture & Ash - Moisture content was determined by oven drying at 105 °C. The ash results were obtained by heating the dried solids at 525 °C.

Heating Value - The heating value was determined using an IKA bomb calorimeter.

Metals Ions - The as-received samples were heat digested with hydrochloric and nitric acids according to the USEPA SW-846 Method 3005A, “Acid Digestion of Waters for Total Recoverable or Dissolved Metals for Analysis by FLAA or ICP Spectroscopy.” Inductively coupled plasma (ICP) spectroscopy analysis was performed on the filtered digestate according to USEPA SW-846 Method 6010B, “Inductively Coupled Plasma-Atomic Emission Spectrometry”, using a Thermo Electron Iris Intrepid

II XDL ICP spectrometer with "Liquor Lab Audit Method." Parameters used for analysis are listed in Table 2.

Table 2. ICP Parameters

Parameter	Setting
Torch Orientation	Radial
R.F. Power	1150 W
Nebulizer Argon Pressure	28 psi (0.50 lpm)
Torch Gas	16 L/min.
Auxiliary Gas	0.50 L/min.
Sample Uptake	2.40 ml/min.
Nebulizer Type	V-Groove
Spray Chamber Type	Cyclone
Purge Gas	Argon
Integration time	20 sec. for UV 10 sec. for visible

Chloride Ions - The as-received samples were heat digested with nitric acid and the chloride content was then determined according to Georgia-Pacific Analytical Method 1108, "Quantification of chloride ions in samples from pulp mills" *via* a Buchler Digital Chloridometer.

Carbonate Ion - Due to the inhomogeneity of the as-received sample, the carbonate ion analysis was done on the oven-dried deposit. The deposit sample was homogenized by crushing with a mortar and pestle prior to analysis. The analysis was done by coulometric titration of the carbon dioxide liberated when the as-received samples were treated with perchloric acid via a UIC® carbon analyzer according to ASTM D513.

ACKNOWLEDGEMENT

I would like to thank Kacee Des Jarlais for the ICP elemental analysis used in this report.

ATTACHMENT C

NCASI TECHNICAL BULLETIN NO. 906

ALTERNATIVE FUELS USED IN THE FOREST PRODUCTS INDUSTRY: THEIR COMPOSITION AND IMPACT ON EMISSIONS

SEPTEMBER 2005

three inches long and about three-quarters inch in diameter or about one inch thick on a side (http://www.plasticsresource.com/s_plasticsresource/sec.asp?TRACKID=&CID=167&DID=272).

Fisher and Tomczyk (2000) provided an overview of the manufacture and use of PEFs. They noted that source separated industrial feedstocks are a preferred type of PEF feedstock in the U.S. because they can be found in concentrated sources and often require little or no processing to remove contaminants, so sourcing costs can be negligible. The most common types include WWTP residuals and secondary fiber rejects from paper mills, absorbent material scrap, waxed corrugated, and other paper scrap. Beck (1998) reported on 32 test burn studies with PEFs for the American Plastics Council. Based on a review of these studies, Fisher and Tomczyk (2000) concluded that

> [r]elative to environmental considerations with the burning of PEFs, air emission analyses based on available data indicate that sulfur dioxide, nitrogen oxide, and carbon monoxide air emissions generally decreased from baseline coal levels when co-firing PEF. However, particulate matter and hydrogen chloride emissions generally increased. Also, co-firing of PEF with coal did not generally result in failure of the resulting ash to meet federal toxicity standards. Greenhouse gas emissions are reduced when PEF is substituted for coal.

10.0 OTHER ALTERNATIVE FUELS – REJECT DIGESTER KNOTS AND LANDFILL GAS

Several other industrial and agricultural byproducts could serve as alternative fuels to be burned in pulp mill boilers. The agricultural byproducts that could be burned include rice hulls, nut shells, and yard waste. No data are available on emissions from burning these byproducts.

One pulp mill boiler conducted extensive tests in its bark/oil-fired combination boiler burning two types of alternative fuels: reject digester knots and WWTP secondary residuals. A baseline run with oil and bark was also carried out. The various fuels burned (bark, oil, WWTP residuals, and reject digester knots) were also fully characterized. Table 10.1 provides the results of analyses for the four fuels including the two alternate fuels burned during the test runs. Note that the residuals and reject digester knots both contain some amount of sulfur. Compared to bark, digester knots have lower nitrogen content, but higher moisture content, and WWTP secondary residuals have higher N, moisture and ash content.

Table 10.2 provides a summary of the air emission data obtained during the tests with the two alternate fuels. This Erie City boiler typically burns about 71% (Btu basis) No. 6 oil through six guns (Btu basis), and the remainder as bark on the grate. Exhaust gases are treated by a multiclone, followed by a caustic scrubber for PM and SO_2 removal. NO_x formation is controlled using low NO_x burners, flue gas recirculation, and overfire air. Emissions of SO_2 and NO_x, and concentrations of O_2 are continuously monitored in this boiler. Table 10.2 includes the measurements for particulate matter (PM), HCl, CO, metals, PCDD/Fs, and PCBs. Table 10.2 shows that the burning of reject digester knots at about 1% of heat input in this bark/oil boiler did not affect the air emissions tested. Similarly, the burning of about 0.8% by heat input of WWTP secondary residuals had no effect on air emissions in this boiler. In order to determine if emissions changed when firing knots or secondary biosolids, the mill used a one-way analysis of variance technique with an alpha level of 0.05. Results from this analysis showed that mean emission rates for the knot and biosolids operating conditions were not statistically different compared to the baseline emission rates.

Another potential source of alternative energy for pulp mills is municipal solid waste (MSW) landfill gas (LFG). MSW contains significant portions of organic materials that produce a variety of gaseous products when dumped, compacted, and covered in landfills. Anaerobic bacteria thrive in the oxygen-free environment, resulting in the decomposition of organic materials and the production of primarily carbon dioxide and methane. Table 10.3 shows the main constituents of LFG and their proportions. As seen from this table, LFGs as fuel are quite similar to natural gas, except that they comprise about 50% methane (the rest CO_2, N_2, H_2O, and O_2), and thus possess about 50% the heat value of natural gas. Table 2.4-1 in Chapter 2.4 of EPA's AP-42 Emission Factor document (http://www.epa.gov/ttn/chief/ap42/ch02/index.html) provides uncontrolled emission concentrations of individual non-methane organic compounds (NMOCs) in LFGs. Table 2.4-3 gives control efficiencies for LFG constituents when these gases are burned in boilers with steam turbines, flares, gas turbines, and IC engines. For LFG burning in boilers, average control efficiencies for NMOCs, halogenated species, and non-halogenated species are given as 98% (range 96 to 99+), 99.6% (87 to 99+), and 99.8% (67 to 99+), respectively. Landfill gas energy facilities capture the methane (the principal component of natural gas) and combust it for energy. At least one pulp mill is exploring the use of LFG from a local MSW landfill in its lime kilns and power boilers.

Table 10.1 Characterization of Bark, Oil, Reject Digester Knots and Secondary WWTP Residuals Burned in Bark/Oil Pulp Mill Boiler

		Samples As-Fired During Trial				Average of 5 Samples[a]	
	Units	Digester Reject Knots	Secondary WWTP Residuals	Bark and Wood Sample	#6 Fuel Oil	Digester Reject Knots	Secondary WWTP Residuals
Sulfur	%	0.53	4.36	0.12	1.24	1.13	2.47
Carbon	%	52.73	37.39	45.8	86.38	49.58	45.49
Hydrogen	%	4.91	4.54	5.67	10.78	5.88	5.48
Nitrogen	%	0.19	3.65	0.28	0.43	0.14	5
Oxygen	%	36.83	15.22	42.79	1.14	34.67	21.1
Heating Value	Btu/lb dry	9,251	6,729	7,944	18,368	7640	7602
Moisture	%	65.5	66.5	39.4	--	54.72	64.01
Ash	%	1.7	11.7	3.2	--	8.58	20.46
Total Chlorides	μg/g	141	54	19	--	2688	994
Total Organic N	μg/g	490	24,000	1,500	4,700	1,146	21,970
Total Kjeldahl N	μg/g	490	24,300	1,500	4,700	1,270	25,960
Ammonia-N	μg/g	<2	348	<2	<2	125	3,990
PCB	μg/g	<1	<1	<1	<1	<1	<1
Metals							
As	μg/g	<2.5	<2.5	<2.5	<2.5	<0.48	<0.4
Cd	μg/g	<0.25	2.4	<0.25	<0.25	<4.8	3.54
Cr	μg/g	<0.25	3.9	0.8	<0.25	<0.48	12.71
Pb	μg/g	<5	17.0	<5	<5	<0.48	31.68
Hg	μg/g	<0.02	0.03	<0.02	<0.02	<0.04	0.042
Se	μg/g	<1	<1	<2.5	<2.5	<0.48	<0.4
Ag	μg/g	<1	<1	<1	<1	<2	<1.6
Be	μg/g	<0.25	0.6	<0.25	0.27	<0.48	<0.4
Cu	μg/g	<2.5	19.0	2.9	<2.5	<4.8	30.8
Zn	μg/g	3.5	205.0	14.0	2.6	7.19	421
Th	μg/g	<0.5	<25	<0.5	<0.5	<1	<0.8
Ni	μg/g	<2.5	64.0	<2.5	39.0	<4.8	141.8
Sb	μg/g	<3	<3	<3	<3	<6	<3[b]
2,3,7,8-TCDD	pg/g	--	3.8	--	--	<0.076	27.3
2,3,7,8-TCDF	pg/g	--	29.0	--	--	<0.12[b]	2.7

[a] as received, analyzed before trial; [b] detected in at least one sample

Table 10.2 Emissions from Burning Reject Digester Knots and Secondary WWTP Residuals in Pulp Mill Bark/Oil Boiler

Boiler Type		Erie City Oil/Bark Boiler w/LNB, FGR, OFA		
PM Control Device(s)		Multiclones + Caustic Scrubber		
Normal Fuels		Primary: No. 6 oil; Secondary: wood chips, bark		
	n[a]	Baseline	Knots[b]	BKM Sludge[c]
Bark/Wood, wet T/day	5	412	325	367
Total Heat Input, MMBtu/hr		564.0	548.0	555.6
Oil (Btu basis)		70.70%	75.10%	72.60%
Bark/Wood (Btu basis)		29.30%	23.90%	26.60%
WWTP residuals (Btu basis)		--	--	0.78%
Knots (Btu basis)		--	0.98%	--
		lb/10^6 Btu	**lb/10^6 Btu**	**lb/10^6 Btu**
PM	5	0.053	0.064	0.064
SO_2		0.47	0.37	0.31
NO_x		0.21	0.22	0.22
CO	5	0.376	0.323	0.024
H_2SO_4		*0.0014*	--	--
HCl	5	0.0018	0.0021	0.0016
Metals (lb/10^6 Btu)				
Antimony	5	*4.4E-07*	*5.2E-07*	*2.7E-07*
Cadmium	5	*3.5E-06*	*2.9E-06*	*1.8E-06*
Calcium	5	2.5E-03	2.4E-03	1.7E-03
Chromium	5	4.2E-06	3.3E-06	2.7E-06
Chromium^{+6}	5	*7.9E-07*	*8.2E-07*	*9.0E-07*
Cobalt	5	8.7E-06	9.4E-06	7.2E-06
Copper	5	2.0E-05	2.0E-05	1.1E-05
Lead	5	3.9E-05	3.9E-05	2.2E-05
Manganese	5	1.3E-04	1.0E-04	8.0E-05
Mercury	5	*2.7E-07*	*4.9E-07*	*3.2E-07*
Nickel	5	3.8E-04	4.1E-04	2.7E-04
Zinc	5	1.9E-03	4.1E-04	3.2E-04
PCDD/Fs (lb/10^6 Btu)				
2,3,7,8,-TCDD	3	ND	ND	ND
1,2,3,7,8-PeCDD	3	ND	ND	ND
1,2,3,4,7,8-HxCDD	3	ND	ND	ND
1,2,3,6,7,8-HxCDD	3	ND	ND	ND
1,2,3,7,8,9-HxCDD	3	ND	ND	ND
1,2,3,4,6,7,8-HpCDD	3	1.13E-12	1.48E-12	1.55E-12
OCDD	3	3.55E-12	4.93E-12	2.34E-11
Total PCDD		4.68E-12	6.41E-12	2.49E-11
2,3,7,8,-TCDF	3	1.77E-12	ND	ND
1,2,3,7,8-PeCDF	3	ND	ND	ND
2,3,4,7,8-PeCDF	3	5.18E-13	ND	ND
1,2,3,4,7,8-HxCDF	3	ND	ND	ND
1,2,3,6,7,8-HxCDF	3	ND	ND	ND
1,2,3,7,8,9-HxCDF	3	ND	ND	ND
2,3,4,6,7,8-HxCDF	3	ND	ND	ND
1,2,3,4,6,7,8-HpCDF	3	ND	ND	ND
1,2,3,4,7,8,9-HpCDF	3	ND	ND	ND
OCDF	3	1.04E-12	ND	8.77E-13
Total PCDF		3.33E-12	0.00E+00	8.77E-13
WHO-TEF/94 TEQs		4.48E-13	1.53E-14	1.79E-14
PCB (Total)	3	*1.07E-08*	*4.32E-09*	*1.61E-09*

LNB = low NO_x burner; FGR = flue gas recirculation; OFA = overfire air; [a] number of tests; data shown are averages; [b] 20.22 wet tons/d of knots fired; [c] 22.94 wet tons/day of residuals fired; *all italicized numbers are non-detects shown at detection limit*

Table 10.3 Landfill Gas (LFG) Constituent Gases
(Sandelli 1992; Doorn, Pacey, and Augenstein 1995)

	Concentration in LFG	
Constituent Gas	Range	Average
Methane (CH_4)	35 to 60 %	50%
Carbon Dioxide (CO_2)	35 to 55%	45%
Nitrogen (N_2)	0 to 20%	5%
Oxygen (O_2)	0 to 2.5%	<1%
Hydrogen Sulfide (H_2S)	1 to 1,700 ppmv	21 ppmv
Halides	NA	132 ppmv
Water Vapor (H_2O)	1 to 10%	NA
Nonmethane Organic Compounds (NMOCs)	237 to 14,294 ppmv	2,700 ppmv

NA = not available; ppmv = parts per million by volume
NOTE: Highest values occur in perimeter wells.

11.0 SUMMARY

This report summarizes available data on the composition of alternative fuels that have been co-fired in pulp and paper mill boilers or lime kilns. These fuels include tire-derived fuel; petroleum coke; tall oil; turpentine; several types of treated wood products including creosote and PCP-treated wood; rejects from pulping of old corrugated containers (OCC rejects); reject knots from kraft digesters; non-recyclable recovered paper; and pulp mill wastewater treatment plant residuals (kraft, sulfite, mechanical pulping, and deinking). For many substances, particularly metals, the composition information provides a reasonable indication of whether emissions from the unit operation in which the alternative fuel(s) is burned are likely to be different than when the primary fuel(s) is burned. For example, the high levels of zinc in tire-derived fuel relative to zinc concentrations in conventional fossil and wood fuels will most likely be reflected in emissions from the unit burning TDF. High chloride levels in the alternative fuels typically result in higher emissions of HCl. However, such simple relationships do not always hold. For example, the high levels of nitrogen in petcoke do not necessarily result in higher NO_x emissions when it is co-fired with other fuels. Also, when sulfur-containing alternative fuels are burned in bark boilers, the SO_2 emission impact may be less than otherwise anticipated due to the sulfur capture capability of the bark or hog fuel ash.

Available emission test data gathered during trial burns or routine use of several alternative fuels were compiled and analyzed. These data suggest burning of most alternative fuels would not have any appreciable impact on emissions of speciated organics, metals, dioxins/furans, HCl, H_2SO_4, and criteria pollutants (SO_2, NO_x, CO, PM, and VOCs). However, site-specific circumstances such as boiler design, operating practices, and pollution control equipment should be considered when assessing the impact on emissions of replacing some fraction of conventional fossil and/or wood residue fuels with one or more alternative fuels.

ATTACHMENT D

HAZARDOUS AIR POLLUTANT EMISSION CALCULATIONS FOR

BARK/WOOD

PULP FIBER REJECT MATERIAL

NATURAL GAS

HAP Summary

	Emission Rates Wood/Pulp Fiber		Emission Rates Natural Gas		Total Emission Rates		
Organic HAPs	ton/yr	lb/yr	ton/yr	lb/yr	ton/yr	lb/yr	>1,000 lb/yr?
Acetaldehyde	1.65	3,936.4	---	---	1.7	3,936	Yes
Acetophenone	5.2E-04	1.2	---	---	0.0	1.2	No
Acrolein	8.0	18,971	---	---	8.0	18,971	Yes
Benzene	8.4	19,919	3.9E-03	7.9	8.4	19,927	Yes
Bis(2-Ethylhexyl)phthalate (also di-)	9.4E-05	0.2	---	---	0.0	0.2	No
Bromomethane (Methyl bromide)	3.0E-02	71.1	---	---	0.0	71.1	No
Carbon Disulfide	0.3	616.5	---	---	0.3	616.5	No
Carbon Tetrachloride	0.1	213.4	---	---	0.1	213.4	No
Chlorine	1.6	3,747	---	---	1.6	3,747	Yes
Chlorobenzene	0.1	156.5	---	---	0.1	156.5	No
Chloroform	0.1	175.5	---	---	0.1	175.5	No
Chloromethane (Methyl Chloride)	4.6E-02	109.1	---	---	0.0	109.1	No
Cumene	3.6E-02	85.4	---	---	0.0	85.4	No
Dichloroethane, 1,2- (Ethylene dichloride)	0.1	137.5	---	---	0.1	137.5	No
Dichloromethane (Methylene chloride)	0.7	1,660	---	---	0.7	1,660	Yes
Dichloropropane, 1,2- (Propylene dichloride)	0.1	156.5	---	---	0.1	156.5	No
Di-n-butyl Phthalate	0.1	156.5	---	---	0.1	156.5	No
Dinitrophenol, 2,4-	5.2E-04	1.2	---	---	0.0	1.2	No
Dinitrotoluene, 2,4-	1.9E-03	4.5	---	---	0.0	4.5	No
Ethylbenzene	0.1	147.0	---	---	0.1	147.0	No
Formaldehyde	8.8	20,868	1.4E-01	280.5	8.9	21,148	Yes
Hexachlorobenzene	0.0	4.7	---	---	0.0	4.7	No
Hexane	0.6	1,375	3.4	6,733	3.9	8,108	Yes
Hydrogen Chloride*	39.8	104,060	---	---	39.8	104,060	Yes
Methanol	1.7	4,079	---	---	1.7	4,079	Yes
MIBK	4.6E-02	109.1	---	---	0.0	109.1	No
Naphthalene	0.2	474.3	1.1E-03	2.3	0.2	476.5	No
4-Nitrophenol	2.4E-04	0.6	---	---	0.0	0.6	No
Pentachlorophenol	1.0E-04	0.2	---	---	0.0	0.2	No
Phenol	0.1	241.9	---	---	0.1	241.9	No
POMs	---	---	9.7E-05	1.94E-01	9.7E-05	0.2	No
Propionaldehyde	0.1	289.3	---	---	0.1	289.3	No
Styrene	3.8	151.8	---	---	3.8	151.8	No
TCDD 2,3,7,8-	0.0	0.0	---	---	0.0	0.0	No
Tetrachloroethene (Tetrachloroethylene or Perchloroethylene)	0.1	246.6	---	---	0.1	246.6	No
Toluene	1.8	4,363	6.4E-03	12.7	1.8	4,376	Yes
Trichloroethane, 1,1,1- (Methyl Chloroform)	0.1	199.2	---	---	0.1	199.2	No
Trichloroethene (Trichloroethylene)	0.1	185.0	---	---	0.1	185.0	No
Trichlorophenol, 2,4,6-	4.8E-05	0.1	---	---	0.0	0.1	No
Vinyl Chloride	3.6E-02	85.4	---	---	0.0	85.4	No
Xylene	5.0E-02	118.6	---	---	0.0	118.6	No
Metal HAPs							
Antimony	1.6E-02	37.5	---	---	0.0	37.5	No
Arsenic	4.4E-02	104.3	3.7E-04	7.48E-01	4.4E-02	105.1	No
Beryllium	2.2E-03	5.2	---	---	0.0	5.2	No
Cadmium	8.2E-03	19.4	2.1E-03	4.1	1.0E-02	23.6	No
Chromium total	4.2E-02	100.4	2.6E-03	5.2	4.5E-02	105.7	No
Chromium VI	7.0E-03	16.6	---	---	7.0E-03	16.6	No
Cobalt	1.3E-02	32.5	1.6E-04	3.14E-01	1.3E-02	32.9	No
Manganese	3.2	7,614	7.1E-04	1.4	3.2	7,615	Yes
Mercury	7.0E-03	16.6	4.9E-04	9.73E-01	7.5E-03	17.6	No
Nickel	0.1	231.7	3.9E-03	7.9	8.0E-02	239.6	No
Phosphorus	0.2	469.5	---	---	0.2	469.5	No
Selenium	6.6E-03	15.7	---	---	6.6E-03	15.7	No
Total HAPs	**82.1**	**195,781**	**3.5**	**7,057**	**85.6**	**202,838**	**Yes**

ATTACHMENT E

NCASI SPECIAL REPORT NO. 09-02

SULFUR CAPTURE IN COMBINATION BARK BOILERS - AN UPDATE

MARCH 2009

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NATIONAL COUNCIL FOR AIR AND STREAM IMPROVEMENT

SULFUR CAPTURE IN COMBINATION BARK BOILERS - AN UPDATE

SPECIAL REPORT NO. 09-02
MARCH 2009

by
Arun V. Someshwar, Ph.D.
NCASI Southern Regional Center
Gainesville, Florida

Acknowledgments

This report was prepared by Dr. Arun V. Someshwar, Principal Research Engineer at the NCASI Southern Regional Center. Dr. John E. Pinkerton, Vice President, Air Quality, provided valuable review of the report contents. Susan Kirkland was responsible for final report preparation.

For more information about this research, contact:

Arun V. Someshwar, Ph.D.
Principal Research Engineer
NCASI Southern Regional Center
402 SW 140th Terrace
Newberry, FL 32669-3000
(352) 331-1745, ext. 226
asomeshwar@ncasi.org

John Pinkerton, Ph.D.
Vice President, Air Quality
NCASI
P.O. Box 13318
Research Triangle Park, NC 27709-3318
(919) 941-6406
jpinkerton@ncasi.org

For information about NCASI publications, contact:

Publications Coordinator
NCASI
P.O. Box 13318
Research Triangle Park, NC 27709-3318
(919) 941-6400
publications@ncasi.org

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PRESIDENT'S NOTE

U.S. pulp and paper mills operate approximately 180 boilers that combust wood fuels. The majority of these boilers cofire other fuels. While natural gas has negligible sulfur content, most of the other cofired fuels contain sulfur. These fuels include coal, fuel oil, kraft mill wastewater treatment plant residuals, and tire-derived fuel. A significant number of wood burning boilers at kraft mills are also used to incinerate noncondensible gases that contain reduced sulfur compounds.

Upon combustion in a boiler, the fuel sulfur will be oxidized mainly to SO_2, with minor amounts of sulfites and sulfates. When coal or oil alone is burned, nearly all the sulfur in the fuel is converted to SO_2 that exits with the other combustion gases. When wood alone is burned, very little of the sulfur in the wood exits the boiler as SO_2. Most of the sulfur in the wood is found in the wood ash in the form of metallic sulfates. Given this difference between the fate of sulfur in coal and oil versus wood, an obvious question is what happens to the sulfur in the fuels when wood is cofired with coal or oil. Would most of the incoming sulfur leave the boiler as SO_2 or would some be retained?

These questions were first addressed in a 1992 NCASI investigation. Fuel sulfur inputs and SO_2 emissions were examined for eight combination boilers cofiring wood with either coal or oil. It was found that a considerable amount of the fuel sulfur was not emitted as SO_2 but rather retained in the ash. The fraction of the input sulfur retained increased as the amount of bark being fired increased relative to the sulfur input. The explanation offered for the observed retention was adsorption of gaseous SO_2 on the carbonaceous wood fly ash with subsequent oxidation to sulfate. Alkali metals in the ash could act as catalyst for the oxidation reactions occurring on the ash. A reasonably good relationship was found between the ratio of sulfur emitted to the amount of wood fuel being fired and the ratio of the total fuel sulfur input to the amount of wood fuel being fired. This relationship has been widely used by NCASI members to estimate SO_2 emissions from combination boilers lacking SO_2 continuous emission monitoring systems.

Additional studies have been carried out since 1992 by various organizations on SO_2 emissions from boilers or laboratory-scale combustion units firing biomass fuels in combination with other fuels. The newer results also show internal capture of fuel sulfur and support the earlier NCASI findings. However, some new insights have been revealed by the more recent investigations and the additional data have been used to refine the earlier understanding. In particular, unburned carbon in the wood fly ash appears to be a critical factor for SO_2 retention. SO_2 retention in fluidized bed combustors and pulverized coal utility boilers cofiring relatively small amounts of wood fuels is much lower than retention in typical combination boilers of the stoker design with grate firing, which have higher unburned carbon levels in their fly ash.

The expanded data set has been used to refine the earlier relationship for estimating SO_2 emissions from combination boilers based on the ratio of the total fuel sulfur input to the amount of wood fuel input (on a dry basis). This predictive relationship should be applicable to the majority of combination boilers located at pulp and paper mills.

Ron Yeske

Ronald A. Yeske

March 2009

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MOT DU PRÉSIDENT

Approximativement 180 chaudières utilisant de la biomasse comme combustible sont en opération dans des fabriques de pâtes et papiers américaines. Dans la majorité de ces chaudières, une combinaison de combustibles peuvent être utilisés simultanément. Même si le gaz naturel contient des quantités négligeables de soufre, la plupart des autres combustibles co-utilisés contiennent du soufre. Ces autres combustibles incluent : charbon, mazout, résidus d'usines de traitement des effluents de fabriques kraft et combustible dérivé de pneus. Un nombre important de chaudières à biomasse de fabriques kraft est aussi utilisé pour incinérer des gaz non-condensables contenant des composés de soufre réduit.

Lors de la combustion dans une chaudière, le soufre contenu dans un combustible sera oxydé principalement sous forme de SO_2, avec quelques traces de sulfites et de sulfates. Lorsque du charbon ou du mazout seul est utilisé comme combustible, presque tout le soufre qu'il contient est converti en SO_2 et ce dernier est émis avec les autres gaz de combustion. Lorsque le bois seul est utilisé comme combustible, seule une faible quantité du soufre contenu dans le bois est émise par la chaudière sous forme de SO_2. La majorité du soufre du bois se retrouve dans les cendres sous forme de sulfates métalliques. Étant donné cette différence de destinée du soufre contenu dans le charbon ou le mazout versus celle du soufre contenu dans le bois, la question concernant le sort du soufre contenu dans les combustibles lorsque du charbon ou du mazout est co-utilisé avec du bois se pose de manière évidente. Est-ce que la majorité du soufre intrant quittera la chaudière sous forme de SO_2 ou est-ce qu'une partie y sera retenue?

En 1992, NCASI a abordé ces questions lors d'une recherche sur le sujet. À ce moment, les intrants de soufre via les combustibles et les émissions de SO_2 ont été examinés pour huit chaudières à combustibles multiples utilisant du bois et du charbon ou du mazout. Les auteurs ont déterminé qu'une portion importante du soufre contenu dans les combustibles n'était pas émise sous forme de SO_2 mais plutôt retenue dans les cendres. La fraction de soufre intrant retenue dans les cendres augmentait en fonction de l'augmentation de la quantité d'écorces utilisée par rapport à l'intrant de soufre. Les auteurs ont expliqué cette rétention observée par le fait que le SO_2 gazeux était adsorbé sur les cendres volantes carbonées provenant de la combustion du bois puis oxydé en sulfates. Les métaux alcalins présents dans les cendres pourraient agir comme catalyseurs des réactions d'oxydation se déroulant sur les cendres. Une adéquation relativement acceptable a été établie entre le ratio de soufre émis et la quantité de bois alimentée à la chaudière comme combustible et le ratio de soufre total intrant dans les combustibles et la quantité de bois alimentée à la chaudière comme combustible. Cette adéquation a été largement utilisée par les compagnies membres de NCASI pour estimer les émissions de SO_2 de chaudières à combustibles multiples n'étant pas dotées de systèmes de mesure en continu des émissions de SO_2.

Depuis 1992, différentes organisations ont réalisé d'autres études au sujet des émissions de SO_2 de chaudières ou d'unités de combustion à l'échelle du laboratoire utilisant des combustibles de type biomasse en combinaison avec d'autres types de combustibles. Les résultats les plus récents montrent aussi une capture interne du soufre contenu dans les combustibles, tel qu'établi dans les études précédentes de NCASI. Par ailleurs, de nouvelles percées ont été mises à jour par les recherches les plus récentes et les données supplémentaires ainsi acquises ont été utilisées pour raffiner la compréhension initiale sur le sujet. En particulier, le carbone imbrûlé contenu dans les cendres volantes provenant de la combustion de bois semble être un facteur critique pour la rétention de SO_2. Le taux de rétention de SO_2 dans des chaudières à lit fluidisé et des chaudières de centrales thermiques employant du charbon pulvérisé et qui utilisent simultanément des quantités relativement faibles de combustible de bois, est beaucoup moindre que le taux de rétention typiquement observé dans des chaudières à combustibles multiples de type stoker avec alimentation au niveau des grilles, ces dernières étant caractérisées par leur niveau élevé de carbone imbrûlé dans les cendres volantes.

Les données récentes supplémentaires ont été utilisées pour raffiner la corrélation précédente permettant d'estimer les émissions de SO_2 de chaudières à combustibles multiples en fonction du ratio de l'intrant de soufre total via les combustibles et la quantité de bois alimentée dans les combustibles (sur une base sèche). Cette corrélation prédictive devrait être applicable à la majorité des chaudières à combustibles multiples utilisées dans les fabriques de pâtes et papiers.

Ronald A. Yeske

Mars 2009

SULFUR CAPTURE IN COMBINATION BARK BOILERS – AN UPDATE

SPECIAL REPORT NO. 09-02
MARCH 2009

ABSTRACT

Factors affecting the in situ sulfur capture within combustion units that cofire biomass and sulfur-containing fuels or waste gases are examined. A review of published literature and analysis of test results for several combination boilers and pilot/laboratory scale furnaces suggests significant capture of the fuel sulfur occurs in bark/biomass-fired boilers of the grate design while little capture occurs in fluidized bed combustors and utility boilers that burn mainly coal with small amounts of wood. The most likely explanation for these observations is a mechanism involving adsorption of SO_2 and O_2 on the activated-carbon-like surfaces of combustion ashes generated in grate-fired bark/biomass boilers, followed by oxidation of SO_2 to SO_3 on this surface and subsequent reaction with adsorbed moisture (H_2O) to form H_2SO_4. Further, the presence of alkali metals in the bark/biomass fly ash, such as Ca and Mg, could hasten the irreversible conversion of the gas-phase SO_2 to metal sulfates in the ash. Since fluidized bed combustors and large utility pulverized coal-fired boilers have much lower levels of unburned carbon in their fly ash, much less sulfur capture via this mechanism is expected in these units.

Sulfur capture data from several combination bark/biomass boilers are used to correlate sulfur input to the boiler and the sulfur output from the boiler (SO_2 emissions). The correlation between Y, the lb S emitted (as SO_2) per dry ton of bark or biomass fired and X, the total lb S in boiler input per dry ton of bark or biomass fired, is expressed as $Y = 0.758X - 2.0255$ with a coefficient of correlation $r^2 = 0.92$. A total of 101 data points were included in this correlation with the data coming from 14 combination boilers and one laboratory furnace. The range of biomass fuels included bark, wood residues, and straw while the sulfur-containing fuels included coal, fuel oil, tire-derived fuel and kraft pulp mill noncondensible gases. This correlation represents a refinement of a somewhat similar relationship developed by NCASI in 1992 with a more limited data set.

KEYWORDS

carbon, coal, combination bark boilers, FBC, NCGs, oil, stoker, SO_2, sulfates, TDF

RELATED NCASI PUBLICATIONS

Technical Bulletin No. 837 (December 2001). *Emissions of sulfuric, hydrochloric, and hydrofluoric acids from combination bark boilers.*

Technical Bulletin No. 640 (September 1992). *Sulfur capture in combination bark boilers.*

Atmospheric Quality Improvement Technical Bulletin No. 96 (August 1978). *Information on the sulfur content of bark and its contribution to sulfur dioxide emissions when burned as a fuel.*

CAPTURE DU SOUFRE DANS LES CHAUDIÈRES À ÉCORCES À COMBUSTIBLES MULTIPLES – MISE À JOUR

RAPPORT SPÉCIAL N^{O} 09-02
MARS 2009

RÉSUMÉ

Cette étude porte sur les facteurs influençant la capture de soufre à l'intérieur d'unités de combustion qui utilisent simultanément de la biomasse et d'autres combustibles contenant du soufre ou des gaz à incinérer. Une revue de littérature ainsi qu'une analyse de résultats de tests effectués sur plusieurs chaudières à combustibles multiples et sur des appareils de combustion à l'échelle pilote/laboratoire indiquent qu'un taux de capture important du soufre contenu dans les combustibles se produit dans les chaudières à écorces/biomasse à lit de grilles (*grate design*) tandis qu'un taux de capture très bas se produit dans les chaudières à lit fluidisé et les chaudières de centrales thermiques qui utilisent principalement le charbon et de faibles quantités de bois. Le mécanisme le plus plausible permettant d'expliquer ces observations est l'adsorption de SO_2 et O_2 sur les surfaces des cendres de combustion des chaudières à écorces/biomasse à lit de grilles, qui s'apparentent à du charbon activé. Cette adsorption est suivie d'une oxydation du SO_2 en SO_3 et, subséquemment, d'une réaction avec l'humidité (H_2O) adsorbée pour former finalement du H_2SO_4. De plus, la présence de métaux alcalins, tels que Ca et Mg, dans les cendres volantes générées par la combustion d'écorces/biomasse peut accélérer la conversion irréversible du SO_2 sous forme gazeuse en sulfates métalliques dans la cendre. Puisque les chaudières à lit fluidisé et les chaudières à charbon pulvérisé de grande capacité des centrales thermiques génèrent des concentrations beaucoup plus faibles de carbone imbrûlé dans leurs cendres volantes, un taux de capture du soufre beaucoup plus faible associé à ce mécanisme est prévu pour ce type d'unités.

Des données sur la capture de soufre de plusieurs chaudières employant différents types de combustibles simultanément avec de l'écorces/biomasse sont utilisées pour corréler l'intrant de soufre dans la chaudière et son extrant de soufre (émissions de SO_2). La corrélation entre Y, le nombre de livres de soufre émis (sous forme de SO_2) par tonne anhydre d'écorces ou de biomasse alimentée et X, le nombre total de livres de soufre entrant dans la chaudière par tonne anhydre d'écorces ou de biomasse alimentée, s'exprime par $Y = 0{,}758X - 2{,}0255$ avec un coefficient de corrélation de $r^2 = 0{,}92$. Un total de 101 données, provenant de 14 chaudières à combustibles multiples et d'une unité de laboratoire, ont été incluses dans cette corrélation. Les types de biomasse (combustible) comprenaient : écorces, résidus de bois et paille tandis que les types de combustibles contenant du soufre comprenaient : charbon, mazout, combustible dérivé de pneus et gaz non-condensables de fabrique de pâte kraft. Cette corrélation constitue le raffinement d'une corrélation relativement similaire qui avait été développée par NCASI en 1992, mais qui utilisait un nombre plus restreint de données.

MOTS CLÉS

carbone, charbon, chaudières à combustibles multiples, chaudières à écorces, lit fluidisé, GNC, mazout, stoker, SO_2, sulfates, dérivé de pneus

AUTRES PUBLICATIONS DE NCASI DANS CE DOMAINE

Bulletin technique n° 837 (décembre 2001). *Emissions of sulfuric, hydrochloric, and hydrofluoric acids from combination bark boilers.*

Bulletin technique n° 640 (septembre 1992). *Sulfur capture in combination bark boilers.*

Amélioration de la qualité de l'air, Bulletin technique n° 96 (août 1978). *Information on the sulfur content of bark and its contribution to sulfur dioxide emissions when burned as a fuel.*

CONTENTS

TABLES

FIGURES

SULFUR CAPTURE IN COMBINATION BARK BOILERS - AN UPDATE

1.0 INTRODUCTION AND SCOPE

Bark and other wood residues such as saw kerf, sander dust, board trim, and wood fines represent a major source of fuel for boilers operated by the forest products industry. SO_2 emissions resulting from the combustion of these wood fuels are minimal since sulfur contents are typically less than 0.1% on a dry basis, and most of this sulfur is retained in the boiler ash (NCASI 1978). The ashes resulting from wood residue or biomass combustion contain significant amounts of oxides and carbonates of alkali metals such as calcium, potassium, and magnesium. When wood fuels are cofired with coal, oil, tire-derived fuel, or kraft mill wastewater treatment plant residuals that contain sulfur, some in situ sulfur capture by the alkaline wood ashes is expected. Capture of sulfur present in kraft pulp mill noncondensible gases (NCGs) is also anticipated when these gases are incinerated in a boiler burning wood fuels.

In the early 1990s, NCASI analyzed available industry-generated data on SO_2 emissions from combination bark boilers and found that significant in situ capture of fuel sulfur was occurring in many instances even before the added impact of a wet scrubber following the boiler was taken into consideration. It was assumed the alkaline nature of the wood/biomass ashes and the "activated carbon-like" properties of the carbonaceous wood ash were responsible for this capture. Compilation and analysis of available SO_2 emission data when bark was burned along with coal, oil, waste treatment plant residuals, and/or NCGs were presented in Technical Bulletin No. 640 (NCASI 1992). A correlation was developed between the percent sulfur captured within a combination bark boiler and the mass ratio of sulfur to bark fired in the combination fuel, the latter being used as a surrogate for the S to alkali metal ratio in the bark or wood residue. This correlation was subsequently improved (Someshwar and Jain 1993) and presented as linear regression plots between the lb S emitted per dry ton of combined solid fuel (bark + other solid fuels) fired and the lb S introduced to the boiler per dry ton of bark fired.

Over the last 15 years, additional data suggesting sulfur capture in bark or biomass boilers cofired with sulfur-containing fuels and sulfur-containing waste gases have become available, as has new evidence that appears to enhance the understanding of potential mechanisms responsible for such in situ S capture. In this report, the decade-old relationship developed by NCASI between the amount of S captured and the S to bark mass ratio in combination fuels fired is first recreated and then further strengthened to include additional, more recent data on SO_2 capture in combination boilers. The additional data include those obtained during a 2001 NCASI study investigating acid gas (sulfuric, hydrochloric and hydrofluoric acid) capture in several combination bark boilers (NCASI 2001), during which testing SO_2 emissions were also monitored. They also include other data either generated by individual mills or reported in the literature, with biomass (bark, straw) firing in boilers/furnaces with cofiring of coal, NCGs, and tire-derived fuel (TDF). Several publications in the literature that include measurements for SO_2 in full-scale or lab-scale boilers that burn wood residues or other forms of biomass in conjunction with some sulfur-containing fuel are also reviewed, and the information presented in these used to shed light on the S capture mechanisms at play in these units.

2.0 EVIDENCE OF SULFUR CAPTURE IN BARK/BIOMASS BOILERS

Evidence of sulfur capture by wood or biomass ash in combination bark/wood residue or biomass-fired boilers has been available for some time, both in the form of measurements of lower than expected SO_2 emissions from such boilers and from an examination of the sulfate content of the resulting combustion ashes. In an early NCASI study (NCASI 1978), the fate of sulfur present in the wood fuel itself was investigated by conducting a sulfur balance around four boilers that fired only wood residues. This balance showed that just over 5% of the sulfur contained in the bark left the boiler as SO_2, with the remainder being accounted for in the bottom and fly ashes.

Data on fly ash particulate sulfate content from several tests conducted by EPA on three combination boilers firing wood residue and fuel oil (Cheney et al. 1979; NCASI 1984) showed soluble sulfates comprised from 35 to 76% of the total particulate catch. Ash from 100% wood combustion typically has sulfate content less than about 3% (expressed as SO_3) (NCASI 1992). Vosler (1985) reported that the substitution of up to 13% by weight of hogged fuel by coal in a boiler resulted in a negligible change in the level of SO_2 emissions. At comparable steam production rates of 160,000 lb/hr, the coal substitution resulted in a less than 6 ppm increase in SO_2 emissions. In Technical Bulletin No. 640 (NCASI 1992), the reduction in expected stack SO_2 emissions in three bark boilers cofiring coal and four bark boilers cofiring oil was investigated and a correlation developed between the percent sulfur removal in the boiler and the ratio of sulfur in the combination fuel fired to the tons of bark fired in the boiler. Someshwar and Jain (1993)further refined this relationship by correlating the ratio of S emitted per dry ton of combined fuel fired to the ratio of S in combined fuel fired per dry ton of bark fired.

The U.S. Environmental Protection Agency summarized the 1989 test results from burning tire-derived fuels (TDFs) in the Dow Corning Midland, Michigan wood-fired boiler (USEPA 1997). At 5, 10 and 15% TDF firing by heat value, SO_2 emissions were reported as 0.028, 0.037 and 0.059 lb/10^6 Btu, respectively. The S content and heat value of the TDF fired were not provided. TDFs typically have sulfur content around 1.56% and a heat content of about 15,260 Btu/lb (NCASI 2005). Using these typical values for TDF, SO_2 capture efficiencies within this wood-fired boiler of 78.3%, 83.9% and 82.1%, respectively, are estimated to have occurred.

James and Caniparoli (1995) discussed how testing at the Weyerhaeuser, North Bend, Oregon mill's two hog fuel boilers showed that SO_2 from fuel oil was being removed, presumably by wood ash, when burned in combination with hog fuel. The two boilers burned hog fuel, used oil and old corrugated container (OCC) rejects, and were equipped with Burley scrubbers (wet) designed to remove particulate matter. Available test results suggested that a major portion of the SO_2 removal was occurring within the boiler, and less removal was occurring in the scrubber water. In lieu of installing continuous emission monitors for SO_2, the mill developed an empirical relationship between the actual S emissions (S_A) and predicted S emissions (S_P) (both in lb/hr). The following quadratic relationship had an R^2 of 0.857 and a standard error of 3.0054.

$$S_A = 14.66 - 1.22 * S_P + 0.04123 * S_P^2$$

The predicted sulfur emissions S_P would be the sum of the sulfur in the hog fuel, the OCC, and the used oil fired. The sulfur emissions would then be multiplied by 2 to give the SO_2 emissions. Based on the data available for limited firing conditions, this equation was applicable to sulfur emissions predicted between 13 and 38 lb/hr.

Nordin (1995) conducted experiments in a small pilot scale fluidized bed (5 kW) that showed sulfur retention of 70 to 75% for a peat-wood fuel mixture and 85 to 90% for a mixture of coal and an energy crop (Lucerne). He identified the products $CaSO_4$ and $3K_2SO_4.Na_2SO_4$ in the ashes and concluded the sulfur retention was due to formation of these sulfates. He also concluded that the sulfur retention was related to the alkali to S mole ratio in the combined fuel. Fuel feeding rate (load), primary air ratio and total air flow were identified as the most influential operating factors, and bed temperature and oxygen concentration appeared to be the most crucial physical-chemical factors for the sulfur retention. Figure 2.1 shows the results from Nordin's study as well as previous full scale tests by Åmand et al. (1986) at a full scale FBC boiler (8 MWe) where $CaCO_3$ was used as sorbent.

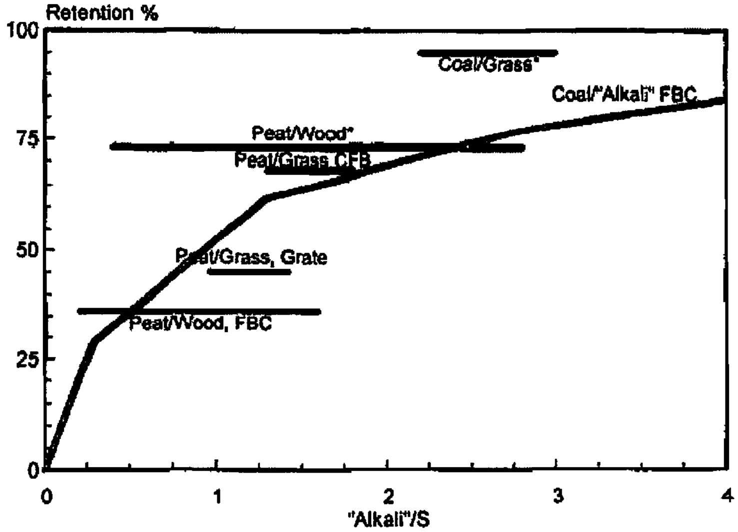

Figure 2.1 Sulfur Retention versus Total "Alkali"-Sulfur Ratio from Some Cocombustion Work, Compared with a Conventional Technique using $CaCO_3$ as Absorbent [* from the present study]

To estimate SO_2 capture within bark boilers, a Midwest kraft mill conducted several tests in 1995 on two of their power boilers. Two sets of tests with varying amounts of bark were carried out on the No. 7 boiler, the first with cofiring of natural gas and kraft pulp mill noncondensible gases (NCGs), and the second with cofiring of coal and NCGs. Tests were also conducted on the No. 9 boiler burning bark, natural gas and NCGs. The results of these tests, presented later in Section 4.0 (boiler codes AA1, AA2 and AB), showed that significant S capture was occurring within these boilers.

Gold and Tillman (1996) reported on the progress of case studies (through 1993) of cofiring wood with coal in several Tennessee Valley Authority (TVA) coal-fired power plants. At the Kingston, Tennessee coal-fired utility (1418 GJ/h), cofiring with 15% of the total heat input from biofuel (wood products mill residues dried by flue gas to 25% moisture) led to the following conclusions.

- During biofuel cofiring, the boiler efficiency loss was less than 1.5% relative to coal-only firing; consequently, it would not be of concern to the boiler operator.
- The flame temperature decreased by about 100°F during cofiring, which had little impact upon boiler operations and also suggested that there would be a small reduction in thermal NO_x during cofiring.

- There is a significant reduction in SO_2 and NO_x emissions (the NO_x reduction was approximately 10%), based upon reducing the amount of sulfur and nitrogen in the fuel blend to the boiler.

A 19% reduction in SO_2 emissions was recorded with a 15% substitution of coal by wood (heat input basis). Unlike other observations, the SO_2 emission reduction recorded here is only marginally better than the substitution rate of wood. As explained later, one possible explanation for this is the low levels of unburned carbon commonly found in ashes from utility boilers.

Pederson et al. (1997) studied the effect of cofiring straw and pulverized coal in a 2.5 MWth pilot-scale burner and a 250 MWe utility boiler. In the 2.5 MWth trial, the straw was chopped and fed separately to the burner, whereas in the full-scale utility boiler, the straw was preprocessed as pellets and ground with the coal in the mills. Two tests with straw fractions at 8 and 21% on a thermal basis were conducted in the full-scale experiment, while several tests ranging in straw fractions from 8 to 47% on a thermal basis were conducted in the pilot-scale experiment. Two low-sulfur coals and one high-sulfur coal were used in the pilot scale, whereas a high-sulfur coal (1.86% S) was used in the full scale. Results from the two tests at 8 and 21% straw, rest coal, in the utility boiler showed only marginal SO_2 reductions (<5%). Results from tests in the pilot-scale burner, especially at levels exceeding 15% straw, revealed that an increased fraction of straw in the fuel blend resulted in a reduction of both NO and SO_2 emissions. The lower SO_2 emission was believed to be partly due to a lower sulfur content of the straw and partly due to retention of sulfur in the ash, probably present as solid alkali sulfates (confirmed by analyses of fly ashes). Equilibrium calculations suggested that at temperatures as high as 1450°K, the increasing sulfur retention with increasing straw fraction could probably be attributed to the formation of potassium sulfate. Formation of calcium sulfate could probably also contribute to sulfur retention, though calcium sulfate is thermodynamically stable only below 1425°K. The authors state that their work did not reveal which sulfate was the main contributor to the sulfur retention. The detailed data and SO_2 emission results are investigated further in Section 4.0.

Helmer, Stokke, and Sun (1998) investigated the effect of wood particle size during the cofiring of debarked, air-dried (8.3% moisture) silver maple wood chips and planer shavings (each separately) with coal (3.1% S) in a small diameter (4.25") fluidized bed combustor. Test runs with 0, 25, 50, 75 and 100% wood (mass basis) were conducted and both SO_2 and NO_x emissions monitored. The authors concluded "the addition of wood to high-sulfur coal results in a slight reduction of the SO_2 emissions at high wood/fuel percentages," i.e., over and beyond that which can be explained by the substitution of wood. The data showed that some "coal sulfur absorption in the combustion ash may have occurred during the wood/coal combustion since some of these data are below the full sulfur conversion (total SO_2) line." From the figures they presented, the SO_2 emission reduction is estimated to have ranged from 1.1 to 11.8% at 25% wood (higher for planer shavings), 19.2 to 20.8% for 50% wood, and 32.5 to 43.8% at 75% wood. The authors also concluded that "particle size had little effect on the absorption of sulfur." This, however, contradicts the fact that at 25% wood, the planar shavings yielded a much higher reduction of SO_2 than the dry chips (1.1 vs 11.8%).

Helmer and Stokke (1998) further investigated the effect of wood moisture content during the cofiring of debarked, air-dried (8.3% moisture) and moist (50% moisture) silver maple wood chips (each separately) with coal (3.1% S) in the same small diameter (4.25") fluidized bed combustor. Similar results of SO_2 reduction were obtained as with the first investigation, except that the percent reduction in SO_2 emissions was essentially zero for both the dry and wet chips at 25% wood substitution. The authors concluded "wood firing with coal produces a slight SO_2 reduction at high wood/fuel ratios" with wood moisture content having no apparent effect.

As part of his doctoral dissertation, Latva-Sompii (1998) conducted experimental studies on pulp and paper mill sludge ash behavior in fluidized bed combustors in which he also looked into the fate of sulfur in fly ash. From a compilation of the bulk ash analysis and measured SO_2 concentrations in flue gases from several industrial bubbling fluidized bed (BFB) combustors burning paper mill sludges, pulp mill sludges and bark (see Table 2.1), 85% to 89% of the sulfur was reported as captured in the fly ash. Latva-Sompii theorized that the high Ca/S ratio in the sludges enhanced the S capture by chemical reaction. This ratio was 19 in the paper mill sludge/bark mixture and 6 in the blend of pulp mill sludge and bark. The author suggested that besides chemical reaction, the high surface areas of the fly ash may have also increased the S capture by heterogeneous condensation of volatile species on the residual ash surfaces. He also noted that higher bed temperatures in bench-scale BFB firing of pulp mill sludges did not increase the SO_2 concentrations in the flue gases. A similar phenomenon showing insensitivity to temperature of sulfur capture was observed by Xiaodong et al. (1997) while firing paper mill sludge in a pilot circulating fluidized bed (CFB) combustor.

Table 2.1 Fate of Sulfur in the Industrial BFBs (Latva-Sompii 1998)

Fuel		Paper Mill Sludge and Bark	Pulp Mill Sludge and Bark	Bark
Ash concentration	weight %	17.7	3.1	2.3
Sulfur concentration	weight %	0.07	0.11	0.03
S of ash-forming species	weight %	0.4	3.5	1.3
S in fly ash	weight %	0.5	3.4	n.a.
Max. SO_2 in flue gases	mg/Nm^3	214	131	70
Measured values	mg/Nm^3	26	19	8
S capture in fly ash		88%	85%	89%
Ca/S molar ratio		18.9	6.1	22.7

Tillman, Battista, and Hughes (1998) reported on the cofiring of wood waste (sawdust) with coal at the Seward generating station. They ran tests with cofiring fresh green sawdust, dry sawdust and shavings, and old sawdust with coal in a large utility boiler, all at levels ranging from 1.47 to 10.3% of total heat input. In all of the 13 tests conducted, the unburned carbon level in the fly ash remained fairly low and constant between 0.78 to 0.95 $lb/10^6$ Btu. The authors state that sulfur dioxide emissions were reduced as a function of the cofiring percentage expressed on a Btu basis. However, "while there is some speculation that the alkalinity of wood ash may further reduce sulfur emissions, this phenomenon was not experienced at the Seward cofiring tests."

Hughes (1998) reported on the results of coal-biomass cofiring tests at six utility boilers including the Seward generating station, with biomass (three sawdust, one wood, one wastewood, one switch grass) fractions ranging up to 10% of the total heat input. Moisture level for the biomass ranged from 10% for the switch grass to 52% for the highest moisture sawdust. The boilers included all major firing types of utility boilers (wall, tangential, and cyclone), ranging in size from 32 to 425 MWe. Similar to results first reported by Gold and Tillman (1996) and later by Tillman, Battista, and Hughes (1998), they saw no substantial reductions in SO_2 emissions over and beyond what can be explained by the level of substitution of coal by biomass. They state "SO_2 and CO_2 reductions achieved with cofiring are directly related to the quantity and chemical contents of the coal displaced by biomass." They also state that "biomass has a much higher volatile content compared to virtually all coals. Thus, biomass cofiring has some potential to increase overall boiler combustion efficiency by reducing levels of unburned carbon in the ash and reducing the amount of excess air required."

The marginal SO_2 emission reduction in utility boilers with <10% substitution of coal by biomass observed by Gold and Tillman (1996) and Tillman, Battista, and Hughes (1998) appears to contradict other findings of higher SO_2 removal during wood cofiring with coal. It appears that in the utility tests where a small fraction of the large amounts of coal fuel is replaced with biomass, compared to when coal or other S-containing fuels are cofired in a predominantly biomass-fired boiler, the low unburned C content of the fly ashes may be instrumental in negating any SO_2 removal effect of the combustion ashes.

Reporting on the effect of wood fuel on SO_2 capture in large fluidized bed boilers, Orjala et al. (2001) stated that tests with a 190 MWth BFB boiler with a blend of 66% wood and 34% peat showed that only 55% of total *fuel sulfur* was released as gaseous emissions. They also report that trials were carried out burning an appropriate amount of wood fuel (bark, sawdust, wood chips and harvesting residues) with peat in three other boilers (290 MWth BFB boiler, 330 MWth CFB boiler and 84 MWth CFB boiler) and in these trials, the sulfur dioxide reduction "was 17%-30% more than that caused by an average sulfur content reduction with a fuel blend."

In 2001, NCASI conducted a study to test for sulfuric acid, hydrochloric acid and hydrofluoric acid emissions from four coal/bark and two residual oil/bark combination boilers to investigate the ability of the bark ash to capture in situ some levels of SO_3/H_2SO_4, HCl and HF in a manner similar to SO_2 (NCASI 2001). Fortunately, SO_2 emissions were also monitored during these test runs (NCASI 2001, Appendix D) and the recorded emissions (presented later in section 4.0) once again confirm the ability of wood ash to capture SO_2 in combination bark boilers. In situ SO_2 capture ranged from 29 to 72% in the four boilers studied.

In studying the ash behavior in a large pulverized wood-fired boiler (80 MWth), Skrifarsa et al. (2004) introduced peat (0.3% S) and elementary sulfur as additives to the main wood fuel (pellets or briquettes of wood, ground into powder) in order to see if there would be any effect of these additions on the ash and ash deposition behavior in the boiler. FTIR analyses of SO_2 and HCl in the stack gases showed that the addition of peat to the wood chips (up to 5% of heat input) did not change the amount of emitted SO_2 and HCl much, but the addition of 0.1% sulfur did. The increase in SO_2 emissions with sulfur addition was accompanied by an increase in HCl emissions, suggesting an effect of SO_2 (g) inhibiting the formation of condensed alkali chlorides. The combustion scenario with 100% wood chips seemed to collect the highest amounts of deposits, and adding either peat or elemental sulfur to the furnace seemed to reduce the deposition rates. The decrease in deposition rates caused by peat was explained by an eroding (cleaning) effect of the peat ash, since there was no significant change in the chemical composition of the deposit when peat was added to the furnace, compared to the case when 100% wood chips were fired alone. The reason for the decreasing effect due to sulfur addition was assumed to be related to a sulfation of the wood ash, which after this would not be as prone to stick onto a heat exchanger surface as it would be in a non-sulfated form. Significant enhancement in the sulfation of the ash was observed from the chemical analyses of the deposits when elemental sulfur was added to the furnace.

Hupa (2005) reviewed recent research on the interaction of various fuels in large-scale fluidized bed combustors (FBC), including the gaseous emissions from cofiring wood and coal. He presents the results of SO_2 emission tests conducted on a 12 MWe CFB boiler at the Chalmers University of Technology in Sweden by Leckner and Karlsson (1993) shown below in Figure 2.2. Based on these data he concludes "sulfur dioxide emission is clearly a simple linear function of the fuel mixture. Practically all of the SO_2 originates in the coal and the higher the share of coal in the mixture the higher the emission. The alkaline ash in the wood is known to be able to capture a fraction of this SO_2, but this fraction seems to be negligible."

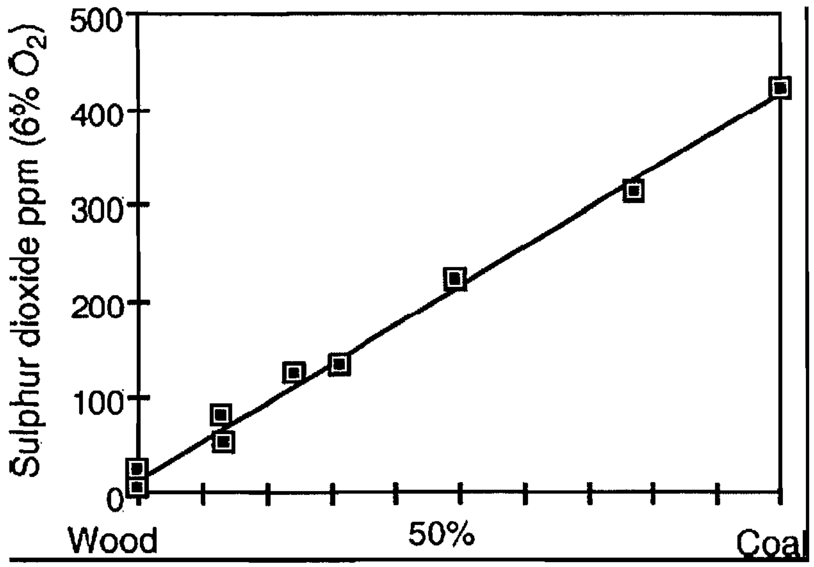

Figure 2.2 SO_2 Emission as Function of Fuel Mixture in Circulating Fluidized Bed During Combustion of Wood and Bituminous Coal. Experimental results from the Chalmers 12 MWe CFBC [Leckner and Karlsson 1993]

Once again, it appears that the highly efficient combustion prevailing in fluidized bed coal combustors and in large utility-scale pulverized coal combustors that results in almost no unburned carbon in the ash might be partly responsible for the observation that SO_2 reduction in such combustors is almost completely explained by the substitution of the low S biomass in place of the high S coal.

Knudsen et al. (2005) conducted laboratory experiments to investigate the capture of chlorine and sulfur by biomass (wheat straw) char and to evaluate the influence of the char matrix on the release of chlorine and sulfur during the combustion of biomass in larger beds. The laboratory experiments indicated that substantial amounts of HCl and SO_2 could be captured in wheat char, relative to its inherent chlorine and sulfur content at 400-800 and 400-950°C, respectively. A maximum in the char capture efficiency was located at ~600°C, where ~85% of the influent HCl and SO_2 was retained at a gas-solid contact time that was similar to that in the bed of a biomass-fired grate boiler. However, in the entire investigated temperature range, significant retentions were obtained. Chemical and spectroscopic analyses further revealed that the capture of HCl was exclusively governed by the inherent metal species (mainly potassium) of the biomass, whereas SO_2 was predominantly captured by the organic char matrix. Thus, the chlorine capture is, as an upper limit, given by the available amount of metals, i.e., the sum of the calcium and potassium content.

During char burnout at temperatures below 600 and 800°C, respectively, the captured chlorine and sulfur were, to a high extent, retained in the bottom ash. However, at higher temperatures, the chlorine and sulfur retention was limited because of the high volatility of KCl and the fact that calcium and potassium were preferably incorporated into silicates, instead of forming sulfates. The combustion of wheat straw in a larger fixed-bed reactor indicated that more chlorine and sulfur could be retained in the bottom ash, compared to that of samples combusted in a laboratory-scale reactor. This was presumably caused by secondary capture of HCl and gaseous sulfur species in the thicker char layer of the larger reactor.

3.0 MECHANISM FOR SULFUR CAPTURE IN COMBINATION BARK BOILERS

Although it is reasonably well known that co-combustion of wood or biomass fuels with sulfur-containing fuels often leads to a reduction in expected SO_2 emissions, there is not a very clear understanding of the precise mechanisms that come into play causing such a reduction. As seen in the previous section, the presence of high levels of sulfates in the combustion ash of combination wood- or biomass-fired boilers has been confirmed by many investigators. In attempting to explain the source of these sulfates, these investigators have generally attributed it to the reaction between SO_2 and alkali metals present in the biomass fuel or ash. However, two factors render this explanation insufficient. First, for alkali sulfates to form by reaction of alkali metals or metal oxides with SO_2, this has to be preceded by the formation of sulfur trioxide (SO_3) from sulfur dioxide (SO_2), and this step is not fully understood. Second, as seen in many instances in the previous section, when coal burned in large utility boilers is marginally substituted by biomass ($\leq$10%), or when biomass is burned in CFBs and FBCs along with coal, almost no additional SO_2 reduction is observed beyond that which is reasonably explained by the reduction of sulfur input to the boiler itself due to such a substitution. If biomass-origin alkali metals reacting with SO_2 were the sole mechanism of sulfur capture, then clearly this was either not happening or the ash surface over which this could happen was not available.

Under normal circumstances, oxidation of SO_2 to SO_3 requires either very high temperatures and an environment with excess oxygen (homogeneous phase oxidation) or a catalyst and an environment with excess oxygen (heterogeneous phase oxidation). Unlike in coal and oil combustion, wood and biomass combustion, even when cofired with coal or oil, is not expected to result in high enough temperatures to cause significant oxidation of SO_2 to SO_3. However, wood or biomass combustion, especially in industrial stoker units, often results in unusually high unburned carbon levels in the ash, and this ash is likely to have similar properties as activated carbon. Pyrolysis or carbonization of several carbonaceous materials, including sawdust and wood, forms activated carbon (Hassler 1963). Wood ash has a small particle size and low density similar to activated carbon (Campbell 1990). The carbon content of wood ash ranges from 1% in fluidized-bed combustion to 70% in inefficient burners, a typical range being 5 to 30% (Greene 1988). The high degree of carbon in wood ash is further evidence of the carbonization process that occurs during wood residue combustion. Activated carbon is a very good catalyst for the oxidation of SO_2 to SO_3 (Hartman, Polek, and Coughlin 1970).

Hartman, Polek, and Coughlin (1970) reviewed the absorptive and catalytic properties of several microcrystalline carbonaceous materials, including activated carbon. Using experimental results of several investigators, they concluded that even at elevated temperatures (representative of sulfur dioxide-bearing flue gases), activated carbon can absorb a considerable amount of sulfur dioxide through catalytic oxidation occurring on the carbon surface. In addition, the presence of water vapor and oxygen enhance the absorption of sulfur dioxide. Under these conditions, sulfur dioxide converts to sulfuric acid and the acid remains on the carbon (Hartman, Polek, and Coughlin 1970). The activated carbon-like wood ash has the added advantage of being able to neutralize the acid formed from sulfur dioxide oxidation due to the significant concentration of alkaline oxides and carbonates in the ash.

Lizzio and DeBarr (1997) investigated the mechanism of SO_2 removal by carbon with the ultimate goal of preparing activated char from Illinois coal with optimal properties for low-temperature (80-150°C) removal of sulfur dioxide from coal combustion flue gas. They state that the reaction of SO_2 with carbon in the presence of O_2 and H_2O at relatively low temperatures (20-150°C) involves a series of reactions that leads to the formation of sulfuric acid as the final product. The overall reaction is $SO_2 + 1/2O_2 + H_2O + C \rightarrow C\text{-}H_2SO_4$. The authors provide the following reaction sequence presented in the literature as being typical to explain SO_2 removal by carbon.

$$C + SO_2 \rightarrow C\text{-}SO_2 \qquad \text{(Eq 1)}$$

$$C + 1/2O_2 \rightarrow C\text{-}O_2 \qquad \text{(Eq 2)}$$

$$C + H_2O \rightarrow C\text{-}H_2O \qquad \text{(Eq 3)}$$

$$C\text{-}SO_2 + C\text{-}O_2 + C\text{-}H_2O \rightarrow C\text{-}H_2SO_4 \qquad \text{(Eq 4)}$$

The sequence implies that SO_2, O_2, and H_2O are all adsorbed on the surface of the carbon in close enough proximity and in the proper steric configuration to react and form H_2SO_4. In their laboratory study, the authors found the SO_2 adsorption capacity of a coal char to be inversely proportional to the amount of oxygen adsorbed on its surface. Temperature-programmed desorption (TPD) was used to titrate those sites responsible for adsorption of SO_2 and conversion to H_2SO_4. On the basis of the results they obtained, they proposed a more detailed mechanism for SO_2 removal by carbon where the rate expression showed SO_2 adsorption to be dependent only on a fundamental rate constant and concentration of carbon atoms designated as free sites.

Lisovskii, Semiat, and Aharoni (1997) studied the enhancement of adsorptive-catalytic cleaning of sulfur dioxide from gases using active carbon treated with concentrated nitric acid. For regenerative SO_2 removal by active carbon, the sulfur dioxide is separated from the stack gas by adsorption, and the adsorbed SO_2 in the presence of oxygen and water is catalytically turned into sulfuric acid, which is then extracted by water or aqueous solutions of H_2SO_4 in the regeneration stage. The authors also cite a similar mechanism, as shown above in equations 1 to 4, for H_2SO_4 formation on activated carbon.

$$SO_{2(gas)} \Leftrightarrow SO_{2(ads)} \qquad \text{(Eq 5)}$$

$$SO_{2(ads)} + O_{(ads)} \Leftrightarrow SO_{3(ads)} \qquad \text{(Eq 6)}$$

$$SO_{3(ads)} + H_2O_{(ads)} \Leftrightarrow H_2SO_{4(ads)} \qquad \text{(Eq 7)}$$

$$H_2SO_{4(ads)} + H_2O_{(liq)} \Leftrightarrow H_2SO_{4(aq)} \qquad \text{(Eq 8)}$$

The amount of SO_2 adsorbed and the rate of its oxidation to SO_2 on the surface (equations 5 and 6) depend on the adsorption capacity and catalytic activity of the active carbon, while fast and complete extraction of sulfuric acid at the water washing stage of the saturated carbon (equation 8) depends on the bond strength of the acid to the surface. These authors state that adsorption of sulfur dioxide on active carbon has been known to be determined by the pore structure and to a large degree by the presence of active groups of acidic or basic character at the surface. An increase in the basicity of the carbon leads to an increase in SO_2 adsorption, and also an increase in the strength of its bond to the surface, resulting in a decrease of SO_2 desorption in an inert gas stream at high temperature. However, the presence of strong basic surface groups in a carbon used for gas desulfurization is not desirable, because the bond with the adsorbed sulfuric acid is also strengthened and thus its extractability by water, and therefore recyclability, is decreased. The chemical nature of the active carbon surface can be modified by an oxidation treatment. Thus, after treatment by nitric acid the overall concentration of surface oxygen increases, the concentration of the basic surface groups decreases significantly and the concentration of the acidic groups increases considerably.

Activated carbon is manufactured by bringing about pyrolysis (or carbonization) of the source material (a carbonaceous substance), followed usually by a stage of controlled oxidation (Hassler 1963). Carbonization is usually conducted in the absence of air. The char resulting from carbonization is subjected to the action of oxidizing agents—steam, air, carbon dioxide—at elevated temperatures. The source materials for preparing activated carbon comprise a host of carbonaceous materials including sawdust and wood (Hassler 1963). Based on the conditions existing within a bark boiler, wood ash resulting from wood combustion may be expected to behave similarly to activated carbon relative to its oxidizing characteristics.

Lee et al. (2002) studied the adsorption characteristics of SO_2 with KOH-impregnated granular activated carbon. Summarizing previous study results with the use of activated carbon to remove sulfur oxides, they state that SO_2 is adsorbed by activated carbon in the form of SO_3 in an SO_2-O_2 atmosphere and in the form of oxidized H_2SO_4 in an SO_2-O_2-H_2O atmosphere. If O_2 and H_2O are added to the reaction, they serve to increase the SO_2 adsorption rate of activated carbon (Lisovskii, Semiat, and Aharoni 1997; Lizzio and DeBarr 1997). Basic surface groups present in activated carbon greatly enhance SO_2 adsorption (Davini 1990). The amount of SO_2 adsorbed may be affected by the chemical features of the basic group. As a result, studies on removing acid gases, such as SO_2, by making the surface of activated carbon more basic through impregnation of alkaline hydroxide have gained much attention.

In summary, sulfur capture within combination wood residue or biomass-fired boilers can occur when the SO_2 formed as a result of gas phase combustion of sulfur or sulfur compounds in the combined fuel adsorbs on to the carbonaceous, activated carbon-like wood/biomass ash surface, oxidizes to SO_3 on this reactive surface by reacting with adsorbed oxygen atoms, and then combines with adsorbed surface moisture to form H_2SO_4. Following this, a part or all of this oxidized H_2SO_4 may react irreversibly with the alkaline metals or metal oxides/carbonates in the ash matrix. In this manner, the ability of wood ash to capture SO_2 may in some instances exceed the equivalent stoichiometric amount of the alkali metal concentration in the wood or biomass fuel. Also, based on this proposed mechanism, the absence in certain instances of significant porous carbon content in the fly ash, as in the case of burning coal with small amounts of biomass in large utility boilers and burning biomass with other sulfur-containing fuels in FBCs/CFBs, would also explain why additional SO_2 removal beyond simple combined fuel sulfur reduction does not appear to occur in such instances.

4.0 ANALYSIS OF DATA FROM NCASI STUDIES, PUBLISHED LITERATURE AND NCASI DATA FILES ON SULFUR CAPTURE IN COMBINATION BARK BOILERS

Table 4.1 reproduces the run-by-run data generated in NCASI Technical Bulletin No. 640 (NCASI 1992) which were also summarized in Someshwar and Jain (1993).

Table 4.1 SO_2 Emission and Capture in Seven Combination Bark Boilers (NCASI 1992)

				Estimated			% Heat Input From			SO_2, lb/10^6 Btu	
Test No.	Boiler Code & Sulfur Fuel	%S in Fossil Fuel	%S in Bark	X, lb S to boiler/t dry bark	Y_2, % SO_2 reductn	Y_1, lb S emitted/t dry bark	Bark	Coal or Oil	Gas	Measured	Expected
1	A (Coal)	1.00	0.028	16.92	26.2%	12.48	45.1	54.9	0.0	0.67	0.91
2	A (Coal)	1.00	0.028	16.21	14.8%	13.82	46.2	53.8	0.0	0.76	0.89
3	A (Coal)	1.00	0.028	15.00	28.0%	10.80	48.2	51.8	0.0	0.62	0.86
4	A (Coal)	1.00	0.028	12.34	47.6%	6.46	53.3	46.7	0.0	0.41	0.78
5	A (Coal)	1.00	0.028	11.65	40.8%	6.90	54.8	45.2	0.0	0.45	0.76
6	A (Coal)	1.00	0.028	11.38	49.4%	5.76	55.4	44.6	0.0	0.38	0.75
7	A (Coal)	1.00	0.028	6.16	55.6%	2.74	70.6	29.4	0.0	0.23	0.52
8	A (Coal)	1.00	0.028	5.58	75.2%	1.38	72.8	27.2	0.0	0.12	0.48
1	B (Coal)	0.95	0.028	11.97	52.2%	5.73	52.8	47.2	0.0	0.36	0.75
2	B (Coal)	0.95	0.028	9.32	66.6%	3.12	59.3	40.7	0.0	0.22	0.66
3	B (Coal)	0.95	0.028	8.06	43.7%	4.53	63.0	37.0	0.0	0.34	0.60
4	B (Coal)	0.95	0.028	7.37	49.3%	3.74	65.2	34.8	0.0	0.29	0.57
5	B (Coal)	0.95	0.028	6.93	70.9%	2.01	66.7	33.3	0.0	0.16	0.55
6	B (Coal)	0.95	0.028	6.24	47.5%	3.28	69.2	30.8	0.0	0.27	0.51
7	B (Coal)	0.95	0.028	5.33	69.7%	1.62	72.8	27.2	0.0	0.14	0.46
8	B (Coal)	0.95	0.028	4.59	49.5%	2.32	76.0	24.0	0.0	0.21	0.42
9	B (Coal)	0.95	0.028	4.16	81.9%	0.75	78.0	22.0	0.0	0.07	0.39
10	B (Coal)	0.95	0.028	3.83	67.0%	1.27	79.6	20.4	0.0	0.12	0.36
11	B (Coal)	0.95	0.028	3.75	60.8%	1.47	80.0	20.0	0.0	0.14	0.36
12	B (Coal)	0.95	0.028	3.57	82.6%	0.62	80.9	19.1	0.0	0.06	0.34
1	C (Oil)	2.15	0.028	6.49	44.3%	3.61	76.7	23.3	0.0	0.33	0.59
2	C (Oil)	2.15	0.028	5.88	45.4%	3.21	78.6	21.4	0.0	0.30	0.55
3	C (Oil)	2.15	0.028	6.73	58.9%	2.76	76.0	24.0	0.0	0.25	0.61
4	C (Oil)	2.15	0.028	5.81	45.0%	3.20	78.8	21.2	0.0	0.30	0.55
5	C (Oil)	2.15	0.028	10.26	46.1%	5.53	66.8	33.2	0.0	0.44	0.82
6	C (Oil)	2.15	0.028	9.50	49.7%	4.78	68.6	31.4	0.0	0.39	0.78
7	C (Oil)	2.15	0.028	5.91	69.2%	1.82	78.5	21.5	0.0	0.17	0.55
9	C (Oil)	2.15	0.028	5.78	50.3%	2.87	78.9	21.1	0.0	0.27	0.54
10	C (Oil)	2.15	0.028	7.60	45.9%	4.11	73.5	26.5	0.0	0.36	0.66
11	C (Oil)	2.15	0.028	4.82	51.1%	2.35	82.1	17.9	0.0	0.23	0.47
12	C (Oil)	2.15	0.028	4.42	59.0%	1.81	83.5	16.5	0.0	0.18	0.44
13	C (Oil)	2.15	0.028	4.33	69.9%	1.30	83.8	16.2	0.0	0.13	0.43
14	C (Oil)	2.15	0.028	5.05	73.4%	1.34	81.3	18.7	0.0	0.13	0.49
15	C (Oil)	2.15	0.028	4.33	60.7%	1.70	83.8	16.2	0.0	0.17	0.43
16	C (Oil)	2.15	0.028	5.75	63.0%	2.13	79.0	21.0	0.0	0.20	0.54
17	C (Oil)	2.15	0.028	11.59	54.6%	5.26	63.9	36.1	0.0	0.40	0.88

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

Table 4.1 Continued

				Estimated			% Heat Input From			SO_2, lb/10^6 Btu	
Test No.	Boiler Code & Sulfur Fuel	%S in Fossil Fuel	%S in Bark	X, lb S to boiler/t dry bark	Y_2, % SO_2 reductn	Y_1, lb S emitted/t dry bark	Bark	Coal or Oil	Gas	Measured	Expected
1	D (Coal)	1.00	0.023	20.80	30.6%	14.43	37.4	22.6	40.0	0.63	0.91
2	D (Coal)	1.00	0.023	20.00	31.4%	13.73	38.7	22.5	38.8	0.62	0.90
3	D (Coal)	1.00	0.023	19.18	29.5%	13.53	39.9	22.2	37.9	0.63	0.89
4	D (Coal)	1.00	0.023	62.52	8.9%	56.99	21.2	54.9	23.9	1.41	1.55
5	D (Coal)	1.00	0.023	55.24	17.5%	45.57	23.5	52.2	24.3	1.25	1.51
6	D (Coal)	1.00	0.023	66.11	13.4%	57.26	20.2	56.5	23.3	1.35	1.56
7	D (Coal)	1.00	0.023	68.85	16.3%	57.63	22.6	74.0	3.4	1.52	1.82
8	D (Coal)	1.00	0.023	194.97	8.2%	178.98	9.0	85.9	5.1	1.88	2.05
9	D (Coal)	1.00	0.023	110.47	11.5%	97.76	14.9	80.2	4.9	1.70	1.92
1	E (Oil)	2.19	0.028	3.39	68.8%	1.06	87.4	12.6	0.0	0.11	0.35
2	E (Oil)	2.19	0.028	3.39	66.0%	1.15	87.4	12.6	0.0	0.12	0.35
3	E (Oil)	2.19	0.028	3.57	48.4%	1.84	86.7	13.3	0.0	0.19	0.37
4	E (Oil)	2.19	0.028	3.57	62.0%	1.36	86.7	13.3	0.0	0.14	0.37
5	E (Oil)	2.19	0.028	5.62	71.8%	1.58	79.5	20.5	0.0	0.15	0.53
6	E (Oil)	2.19	0.028	5.62	71.8%	1.58	79.5	20.5	0.0	0.15	0.53
1	F (Oil)	2.11	0.028	17.37	-30.0%	22.57	54.2	45.8	0.0	1.39	1.07
2	F (Oil)	2.11	0.028	28.25	28.4%	20.22	41.8	58.2	0.0	0.96	1.34
3	F (Oil)	2.11	0.028	26.50	22.7%	20.48	43.4	56.6	0.0	1.01	1.31
4	F (Oil)	2.11	0.028	11.80	13.6%	10.19	63.9	36.1	0.0	0.74	0.86
5	F (Oil)	2.11	0.028	68.68	28.5%	49.07	22.6	77.4	0.0	1.26	1.76
6	F (Oil)	2.11	0.028	108.17	19.7%	86.89	15.6	84.4	0.0	1.54	1.92
7	F (Oil)	2.11	0.028	70.67	10.4%	63.33	22.1	77.9	0.0	1.59	1.77
8	F (Oil)	2.11	0.028	26.60	44.2%	14.84	43.3	56.7	0.0	0.73	1.31
9	F (Oil)	2.11	0.028	91.17	1.3%	89.98	18.0	82.0	0.0	1.84	1.86
10	F (Oil)	2.11	0.028	6.60	25.3%	4.93	76.7	23.3	0.0	0.43	0.58
11	F (Oil)	2.11	0.028	5.85	-16.2%	6.80	79.0	21.0	0.0	0.61	0.52
1	H (Oil)	2.20	0.028	18.83	25.2%	14.08	51.9	48.1	0.0	0.87	1.16

Ten data points with $X > 50$ and 2 with negative SO_2 removal efficiencies were rejected for developing correlation

Figure 4.1 shows the relationship between the sulfur emitted (as SO_2) and the sulfur in the combined fuel for the seven combination bark boilers, three burning bark and coal, and four burning oil and coal. Just as shown in the summary Figure 6 of Someshwar and Jain (1993), the correlation between Y, expressed here as lb sulfur emitted per dry ton of bark fired, and X, expressed as lb sulfur in combined fuel per dry ton of bark fired, is seen to be excellent, with a correlation coefficient r^2 of 0.95. The X – Y correlation coefficient r^2 observed in Someshwar and Jain (1993) was 0.91. However, Y was expressed slightly differently, namely as lb sulfur emitted per dry ton of combined fuel fired. This newer denotation of Y in the current report, namely as lb S per dry ton of bark fired, appears to be more consistent with the phenomenon of sulfur capture in bark or biomass ash in that it simply represents the fraction of X, the lb sulfur in combined fuel per dry ton of bark or biomass fired that is emitted. In Figure 4.1, the diagonal line denoted as X = Y represents zero capture efficiency for sulfur in the boiler. The gap between this line and the linear regression line for the measured data points is an indicator of the extent of sulfur capture within these boilers. As noted in the figure and in

Table 4.1, 10 data points with X >50 were rejected from inclusion in the analysis. When X exceeds 50, this generally refers to very low levels of bark combustion (25% or less heat input). Inclusion of these data, which comprise a rather small fraction of the total, is seen to skew the analysis unnecessarily, especially for X >100. Two data points with negative SO_2 removal efficiencies were also rejected for the analysis (as these may have occurred as a result of measurement error, inaccurate values for heat inputs, etc.).

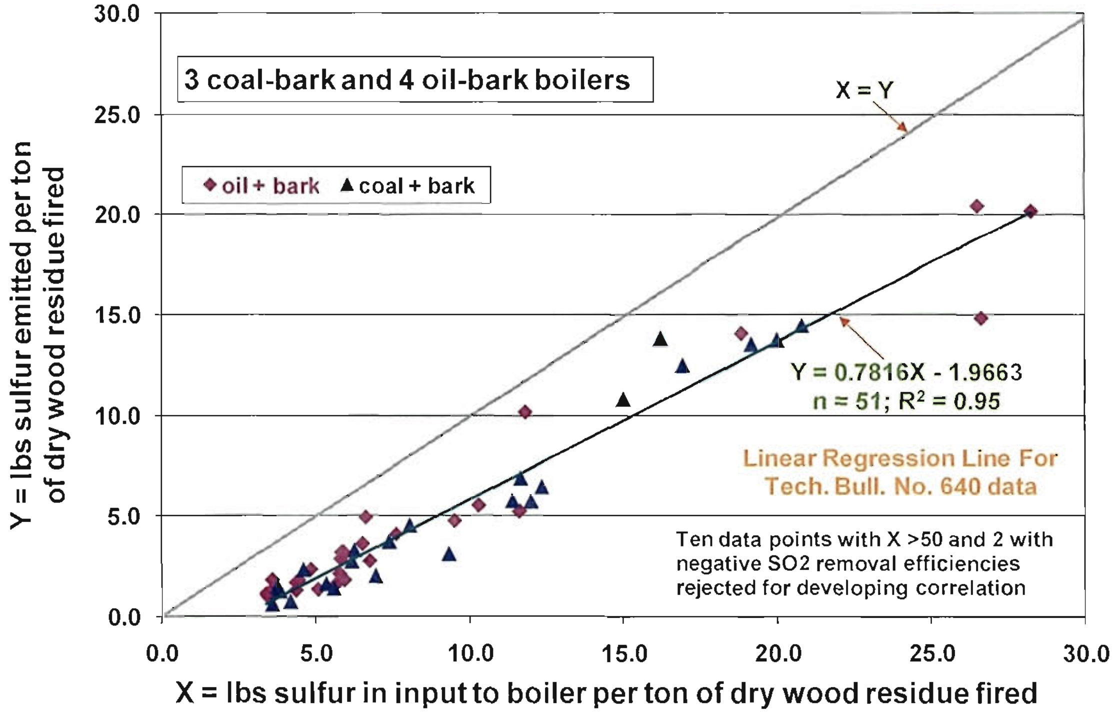

Figure 4.1 Correlation between Sulfur Emitted and Sulfur in Input for Seven Combination Bark Boilers (data extracted from NCASI 1992)

Figure 4.2 shows the relationship between the percent sulfur captured within a combination bark boiler and the amount of sulfur in the combined fuel ((Y-X)/X • 100 vs X, where Y is from Figure 4.1). Just as in the summary Figure 6 of Someshwar and Jain (1993), it is seen that when expressed in this fashion the correlation is somewhat weak.

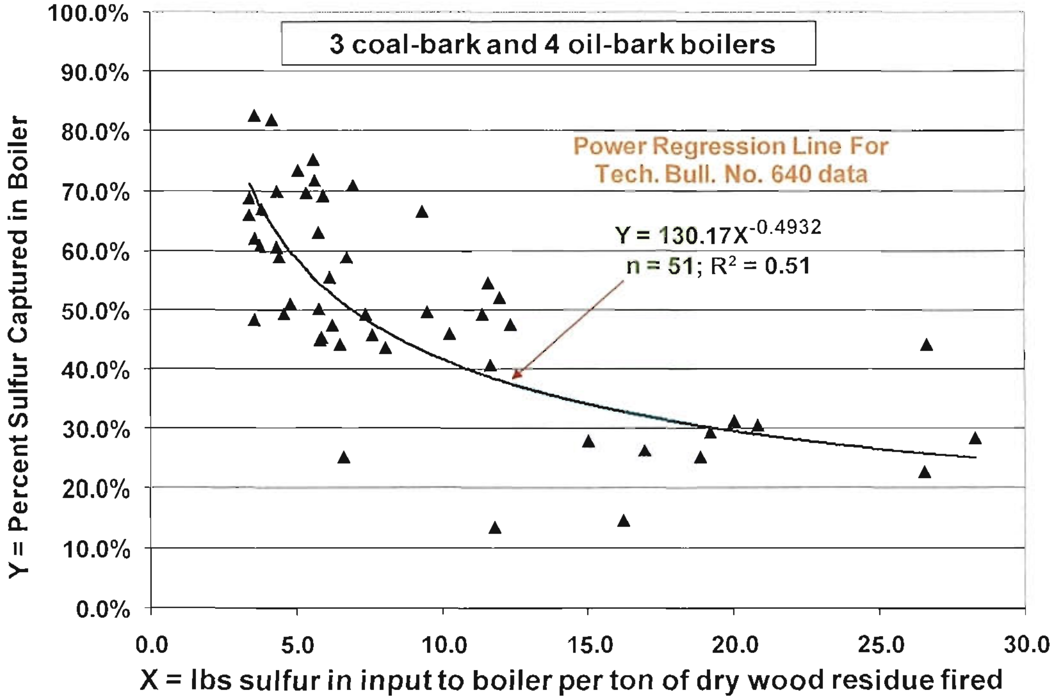

Figure 4.2 Correlation between Percent Sulfur Captured in Boiler and Sulfur in Combined Fuel for Seven Combination Bark Boilers (data extracted from NCASI 1992)

Table 4.2 provides the data generated in NCASI Technical Bulletin No. 837 (NCASI 2001) which, as mentioned earlier, was a study designed mainly to investigate the effect of bark combustion in combination bark boilers on emissions of H_2SO_4 and HCl. However, SO_2 emissions were also recorded during these tests and were provided in Appendix D (NCASI 2001).

Figure 4.3 shows the relationship between the sulfur emitted and the sulfur in the combined fuel for the four combination bark boilers in this study, two burning bark and coal, and two burning bark and oil. Once again, the correlation between Y, expressed as lb sulfur emitted per dry ton of bark fired, versus X, expressed as lb sulfur in combined fuel per dry ton of bark fired, is seen to be quite good, with a correlation coefficient r^2 of about 0.89.

Figure 4.4 shows the relationship between the sulfur emitted and the sulfur in the combined fuel for the eleven boilers for which data were available in NCASI Technical Bulletins Nos. 640 and 837. The correlation coefficient r^2 between Y and X is 0.93 and the total number of data points was 75: 51 from Technical Bulletin 640 and 24 from Technical Bulletin 837.

Table 4.2 Detailed SO_2 Emission and Capture Data from NCASI (2001)

				Estimated			% Heat Input From			SO_2, lb/10^6Btu	
Test No.	Boiler Code & Sulfur Fuel	%S in Fossil Fuel	%S in Bark	X, lb S to boiler/t dry bark	Y_2, % SO_2 reductn	Y_1, lb S emitted/t dry bark	Bark	Coal or Oil	Gas	Measured	Expected
1	A (Coal)	1.27	0.030	15.70	63.0%	5.81	40.7	40.1	19.2	0.28	0.80
2	A (Coal)	1.27	0.030	42.58	40.7%	25.25	21.9	60.0	18.1	0.68	1.17
3	A (Coal)	1.27	0.030	36.48	42.5%	20.98	24.3	56.9	18.8	0.62	1.11
4	A (Coal)	1.27	0.030	45.61	46.6%	24.35	22.3	65.5	12.2	0.67	1.28
5	A (Coal)	1.24	0.030	30.77	28.7%	21.94	26.7	52.9	20.4	0.78	1.01
6	A (Coal)	1.24	0.030	28.63	34.9%	18.64	27.0	49.7	23.3	0.56	0.95
7	A (Coal)	1.24	0.030	33.99	24.2%	25.77	25.9	56.8	17.3	0.84	1.08
8	A (Coal)	1.24	0.030	30.94	21.5%	24.29	27.1	54.0	18.9	0.81	1.03
9	A (Coal)	1.24	0.030	29.24	23.8%	22.28	28.5	53.6	17.9	0.78	1.02
10	A (Coal)	1.24	0.030	27.43	31.8%	18.71	25.2	44.4	30.4	0.76	0.85
11	A (Coal)	1.24	0.030	34.10	31.2%	23.46	24.0	52.8	23.2	0.69	1.00
1	D (Coal)	2.31	0.020	12.93	51.5%	6.27	69.0	31.0	0.0	0.54	1.12
2	D (Coal)	2.31	0.020	12.24	59.4%	4.97	70.2	29.8	0.0	0.43	1.08
3	D (Coal)	2.31	0.020	15.36	57.3%	6.56	65.1	34.9	0.0	0.54	1.25
4	D (Coal)	2.31	0.020	14.58	61.4%	5.63	66.3	33.7	0.0	0.47	1.21
5	D (Coal)	2.31	0.020	14.90	71.8%	4.20	65.8	34.2	0.0	0.35	1.23
6	D (Coal)	2.31	0.020	14.84	54.5%	6.75	65.9	34.1	0.0	0.56	1.23
1	C (Oil)	2.44	0.050	9.83	50.4%	4.88	73.3	26.7	0.0	0.43	0.80
2	C (Oil)	2.44	0.050	10.37	45.0%	5.70	70.9	27.4	1.7	0.49	0.82
3	C (Oil)	2.44	0.050	8.48	37.8%	5.27	74.9	23.1	0.0	0.49	0.70
4	C (Oil)	2.44	0.050	10.70	41.8%	6.23	70.0	28.0	2.0	0.52	0.83
1	B (Oil)	2.83	0.010	10.11	39.9%	6.08	74.3	25.7	0.0	0.48	0.83
2	B (Oil)	2.83	0.010	3.00	58.7%	1.24	91.1	8.9	0.0	0.11	0.30
3	B (Oil)	2.83	0.010	28.06	58.7%	11.59	50.7	49.3	0.0	0.63	1.57
1	D (Coal)	2.31	0.020	12.93	51.5%	6.27	69.0	31.0	0.0	0.28	0.80

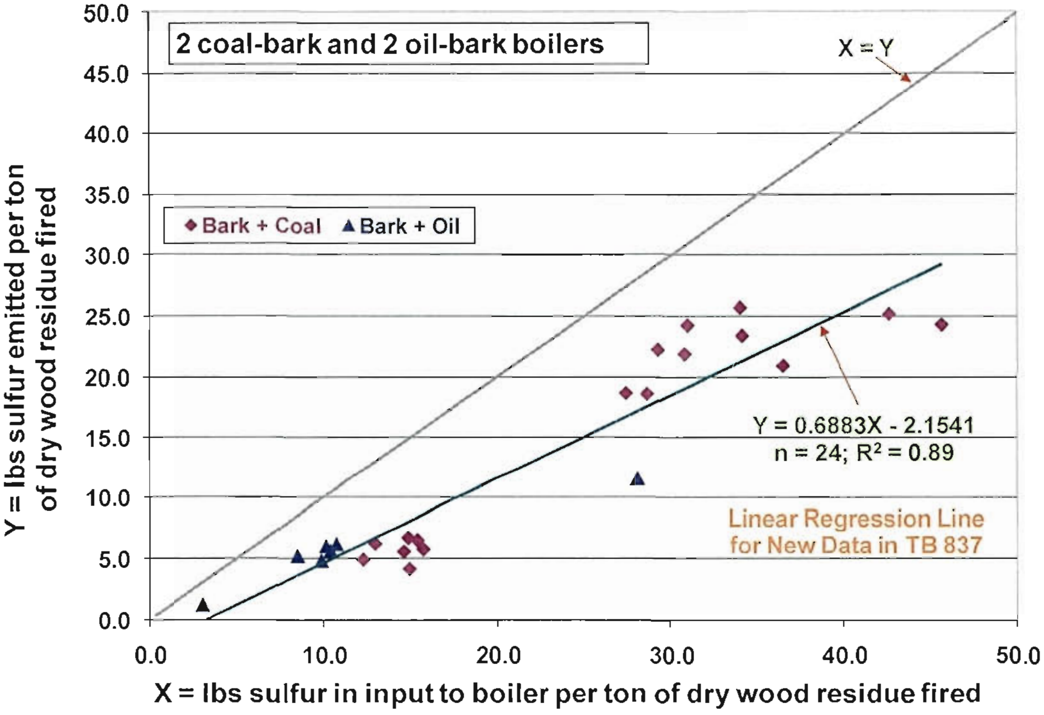

Figure 4.3 Correlation between Sulfur Emitted and Sulfur in Input for Four Combination Bark Boilers (data extracted from NCASI 2001)

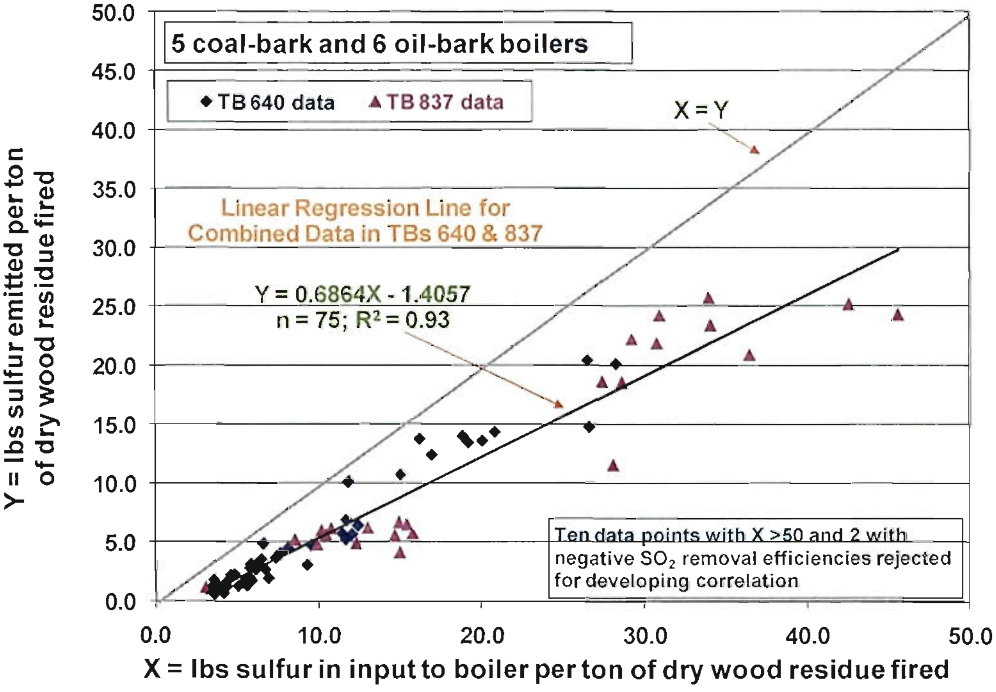

Figure 4.4 Correlation between Sulfur Emitted and Sulfur in Input for Four Combination Bark Boilers (data extracted from NCASI 1992, 2001)

Table 4.3 provides the data generated during trials at one kraft pulp mill that intended "to investigate how boiler ash impacts SO_2 emissions." Two sets of tests were performed in Boiler No. 7 (120 KPPH), one burning bark, natural gas and sulfur-containing NCGs, and another burning bark, coal and NCGs. Separate tests with just bark and NCGs and coal and NCGs allowed one to estimate the sulfur input from the NCGs alone and from the coal alone. The mill also conducted tests on its No. 9 boiler (225 KPPH) burning bark, natural gas and NCGs. A total of 16 data points were generated on the bark sulfur capture in these boilers. However, two data points with X >50 were rejected for the analysis.

Table 4.3 Mill AA Testing "To Investigate How Boiler Ash Impacts SO_2 Emissions"
4/30 to 5/5/95 - Bark/Gas/NCG and Coal

				Estimated			% Heat Input From			SO_2, $lb/10^6Btu$	
Test No.	Boiler Code	%S in Fossil Fuel	%S in Bark[1]	X, lb S to boiler/t dry bark	Y_2, % SO_2 reductn	Y_1, lb S emitted/t dry bark	Bark	Coal or Oil	Gas	Measured	Expected
No. 7 Boiler (120 KPPH steam) - Bark, Natural Gas & NCG											
1	AA1		0.028	40.46	7.6%	37.38	20.0	0.0	80.0	0.89	0.96
2	AA1		0.028	20.51	7.9%	18.90	40.0	0.0	60.0	0.90	0.98
3	AA1		0.028	13.86	40.4%	8.26	60.0	0.0	40.0	0.59	0.99
4	AA1		0.028	13.86	35.4%	8.96	60.0	0.0	40.0	0.64	0.99
5	AA1		0.028	20.51	32.4%	13.86	40.0	0.0	60.0	0.66	0.98
6	AA1		0.028	40.46	15.9%	34.02	20.0	0.0	80.0	0.81	0.96
7	AA1	**100% Nat Gas and NCG run**					0.0	0.0	100.0	0.95[2]	
No. 7 Boiler (120 KPPH steam) - Bark, Coal & NCG											
1	AA2	0.49[1]	0.028	66.67[3]	8.0%	61.32	20.0	80.0	0.0	1.46	1.59
2	AA2	0.49	0.028	30.34	47.4%	15.96	40.0	60.0	0.0	0.76	1.44
3	AA2	0.49	0.028	18.23	51.6%	8.82	60.0	40.0	0.0	0.63	1.30
4	AA2	0.49	0.028	30.34	43.9%	17.01	40.0	60.0	0.0	0.81	1.44
5	AA2	0.49	0.028	66.67[3]	21.9%	52.08	20.0	80.0	0.0	1.24	1.59
7a	AA2	**100% coal and NCG runs**					0.0	100.0	0.0	1.73[4]	
No. 9 Boiler (225 KPPH steam) - Bark, Natural Gas & NCG											
1	AB		0.028	21.84	38.5%	13.44	20.0	0.0	80.0	0.32	0.52[5]
2	AB		0.028	11.20	36.3%	7.14	40.0	0.0	60.0	0.34	0.53
3	AB		0.028	7.66	52.5%	3.64	60.0	0.0	40.0	0.26	0.55
4	AB		0.028	5.88	57.2%	2.52	80.0	0.0	20.0	0.24	0.56

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[1] an uncontrolled SO_2 emission factor for bark firing of 0.067 lb/MM Btu is estimated assuming 8,400 Btu/lb & 0.028% S (both dry basis)

[2] the uncontrolled SO_2 emission factor for NCG firing obtained from this test is assumed to apply to other tests with NCG firing in the No. 7 boiler since the total steaming rate was generally held constant at around 120 KPPH

[3] data with X > 50 rejected for developing correlation

[4] an uncontrolled SO_2 emission factor for coal firing of 0.78 lb/MM Btu is estimated from SO_2 emission factors for 100% coal/NCG firing (1.73) and 100% gas/NCG firing (0.95)

[5] an uncontrolled NCG firing SO_2 emission factor of 0.507 is estimated for this boiler (0.95 x 120/225)

Table 4.4 provides selected data from an EPA report (USEPA 1997) on tire combustion where SO_2 emission data were reported for three levels of tire burning in a bark boiler at the Dow Corning, Midland, Michigan wood waste boiler.

Table 4.4 Tire-Derived Fuel Firing in Wood Waste Boiler (USEPA 1997)

				Estimated			% Heat Input From			SO_2, lb/10^6Btu	
Test No.	Boiler Code	%S in TDF[1]	%S in Bark[2]	X, lb S to boiler/t dry bark	Y_2, % SO_2 reductn	Y_1, lb S emitted/t dry bark	Bark	TDF	Gas	Measured	Expected
1	AC	1.56	0.028	0.56	61.2%	0.22	100.0	0.0	0.0	0.026	0.067
2	AC	1.56	0.028	1.46	78.3%	0.32	95.0	5.0	0.0	0.028	0.129
3	AC	1.56	0.028	2.47	83.9%	0.40	90.0	10.0	0.0	0.037	0.230
4	AC	1.56	0.028	3.59	82.1%	0.64	85.0	15.0	0.0	0.059	0.330

[1] assumed mean values of 1.56%S and 15,261 Btu/lb TDF from Technical Bulletin 906, Table 3.3 (NCASI 2005)

[2] assumed 8,400 Btu/lb and 0.028% S in bark

Finally, Table 4.5 provides SO_2 emission data during the cofiring of straw (biomass) in a 2.5 MWe pilot-scale burner (Pedersen et al. 1997). Eleven data points were generated with burning two different types of coal with straw heat input fractions ranging from 8 to 47%. However, three of the data points had X exceeding 50, and these were not included in the final analysis.

Table 4.5 Effects on SO_x and NO_x Emissions by Cofiring Straw and Pulverized Coal in a Pilot-Scale Furnace (Pedersen et al. 1997)

				Estimated			% Heat Input From			SO_2, lb/10^6Btu	
Test No.	Boiler Code	%S in Coal	%S in Straw	X, lb S to boiler/t dry straw	Y_2, % SO_2 reductn	Y_1, lb S emitted/t dry straw	Straw	Coal	Gas	Measured	Expected
	Cofiring Straw With Coal (Pilot-Scale - Gottelborn coal)										
1	AD1	1.00	0.140	119.75[1]	11.6%	105.85	8.0	92.0	0.0	1.312	1.485
2	AD1	1.00	0.140	70.86[1]	2.4%	69.18	13.0	87.0	0.0	1.394	1.428
3	AD1	1.00	0.140	49.13	13.1%	42.68	18.0	82.0	0.0	1.191	1.370
4	AD1	1.00	0.140	28.95	28.6%	20.66	28.0	72.0	0.0	0.896	1.256
5	AD1	1.00	0.140	20.88	32.4%	14.11	36.0	64.0	0.0	0.787	1.165
	Cofiring Straw With Coal (Pilot-Scale - Med Mac coal)										
1	AD2	0.80	0.140	81.59[1]	15.0%	69.35	9.0	91.0	0.0	0.967	1.137
2	AD2	0.80	0.140	34.97	21.0%	27.62	19.5	80.5	0.0	0.834	1.056
3	AD2	0.80	0.140	22.84	28.0%	16.44	28.0	72.0	0.0	0.713	0.991
4	AD2	0.80	0.140	18.62	32.0%	12.66	33.0	67.0	0.0	0.647	0.952
5	AD2	0.80	0.140	16.07	34.0%	10.60	37.0	63.0	0.0	0.608	0.921

[1] data with $X > 50$ rejected for developing correlation

Figure 4.5 summarizes all the in situ bark/biomass boiler sulfur capture data obtained for the 14 combination bark boilers and one pilot-scale burner. The correlation between Y, expressed as lb sulfur emitted per dry ton of bark/biomass fired, versus X, expressed as lb sulfur in combined fuel per dry ton of bark/biomass fired, is seen to be quite good, with a correlation coefficient r^2 of 0.92. A total of 101 data points were included in this linear regression analysis.

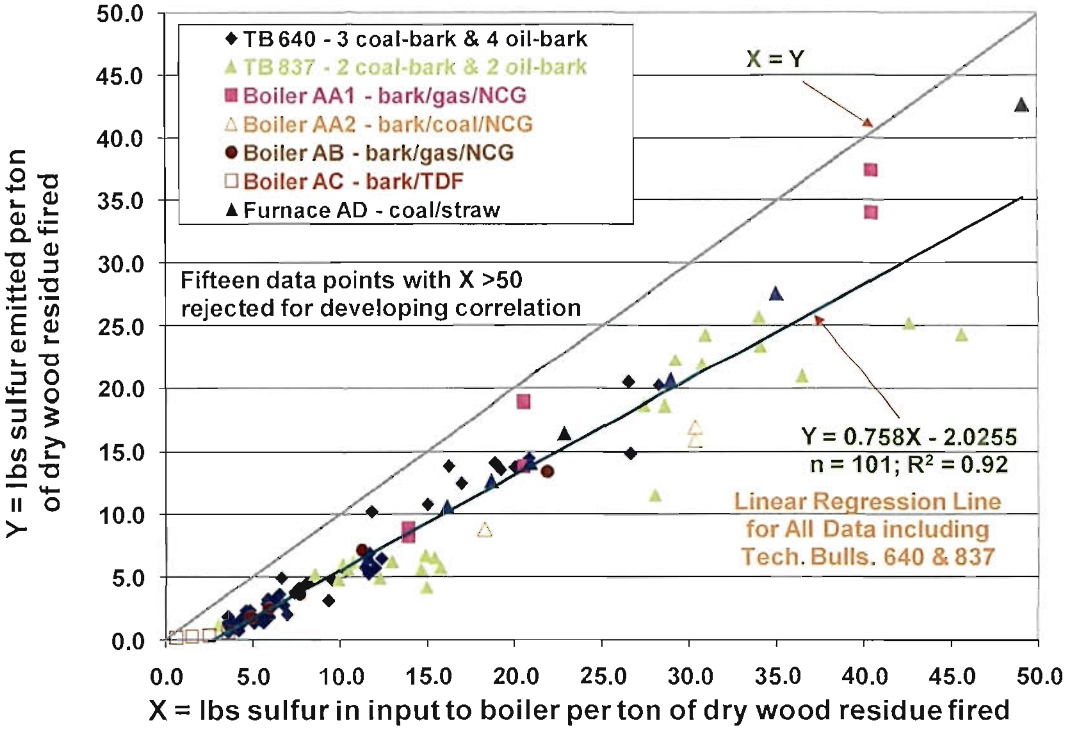

Figure 4.5 Correlation between Sulfur Emitted and Sulfur in Input for Fourteen Combination Bark Boilers and One Pilot-Scale Furnace

Figure 4.6 shows the relationship between the percent sulfur captured within a combination bark/biomass boiler and the amount of sulfur in the combined boiler fuel ((Y-X)/X • 100 vs X, where Y is from Figure 4.5). Once again, as in Figure 4.2 which summarized the data from the earlier NCASI study (NCASI 1992), it is seen that when expressed in this fashion the correlation is somewhat weak. Nevertheless, it is interesting to note that even for X values of over 30 there appears to be at least 25% sulfur capture in these boilers.

Table 4.6 provides the minimum and maximum concentration of alkali metals (Ca, K, Mg and Na) found in the combustion ashes of eight pulp mill bark boilers operating in the southeastern U.S. (Muse 1993). For bark ash contents ranging from 3 to 8% (dry basis), assuming all the alkali metal is tied up with fuel sulfur in a combination bark boiler, the theoretical amount of sulfur tied up with the alkali metals in this fashion is also estimated in Table 4.6. It is seen from this that the maximum amount of sulfur that could potentially be tied up with the four main alkali metals in bark boiler ashes ranges from 14 to 37 lb per dry ton of bark fired for bark ash contents ranging from 3 to 8%. This would suggest that at least some of the SO_2 or sulfur captured in boilers where the lb S/dry ton of bark fired exceeds say 30 (X in Figures 4.1 through 4.6) cannot be explained by the alkali metal reaction with adsorbed SO_2 alone. The amount of SO_2 or sulfur captured by adsorption onto the activated-carbon-like ash surface could therefore exceed the maximum amount that could potentially react with the alkali metals in the wood or biomass combustion ash.

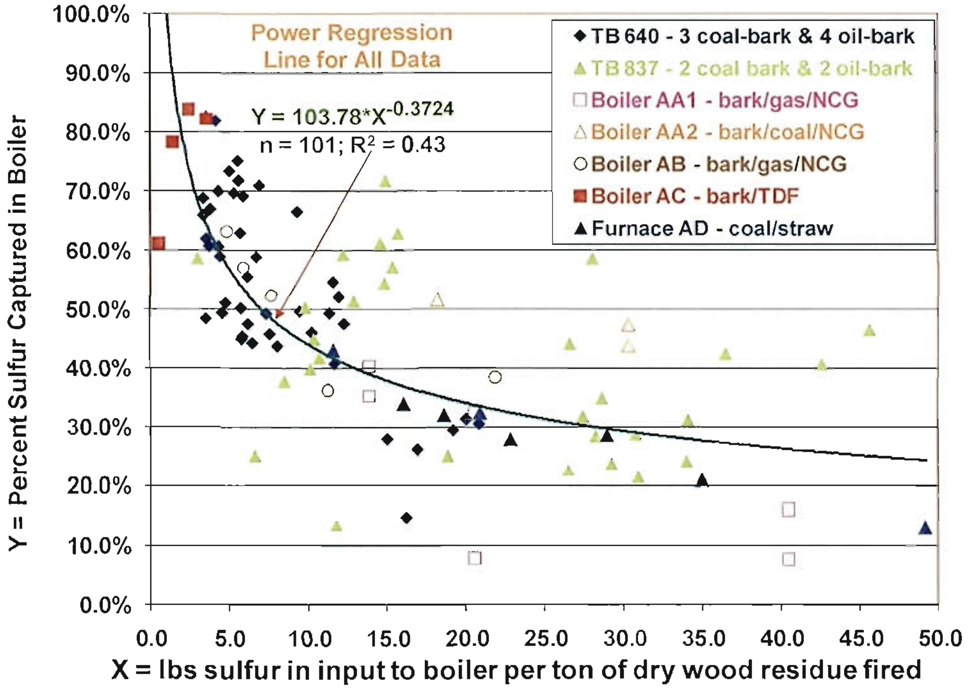

Figure 4.6 Percent Sulfur Capture versus Sulfur in Input for Fourteen Combination Bark Boilers and One Industrial Furnace

Table 4.6 Analysis of Alkali Content in Bark-fired Boiler Ashes for Equivalent Sulfur Capture

% ash in bark ↓	Ca (MW = 40.1)		K (MW = 39.1)		Mg (MW = 24.3)		Na (MW = 23.0)		Total	
	min	max	min	max	min	max	min	max	min	max
	g/kg ash - bark-fired boiler ash data from 8 southeastern pulp mill boilers (Muse 1993)									
	77.5	235.0	13.1	37.1	4.3	22.4	0.6	1.8		
	lb S equivalent of alkali in one ton dry bark[1]									
8.0%	9.90	30.02	0.86	2.43	0.91	4.72	0.07	0.20	11.73	37.37
7.0%	8.66	26.27	1.46	4.15	0.48	2.50	0.07	0.20	10.67	33.12
6.0%	7.43	22.51	1.26	3.55	0.41	2.15	0.06	0.17	9.15	28.39
5.0%	6.19	18.76	1.05	2.96	0.34	1.79	0.05	0.14	7.62	23.66
4.0%	4.95	15.01	0.84	2.37	0.27	1.43	0.04	0.11	6.10	18.93
3.0%	3.71	11.26	0.63	1.78	0.21	1.07	0.03	0.09	4.57	14.19

[1] estimate of S needed to combine with all of Ca, K, Mg or Na to form the corresponding alkali metal sulfate

5.0 ADDITIONAL S CAPTURE DATA FROM TDF BURNING IN TWO PULP MILL BOILERS

Two sets of SO_2 emission data generated by individual mills firing tire-derived fuel in predominantly bark-fired boilers recently became available to NCASI. In this section, these data are plotted against the simplified linear regression correlation developed in Figure 4.5 of the previous section in order to judge the correlation's general validity. These data were not included in the previous summary as the sulfur input to the boiler from the TDF ranged from only 0 to about 5.5 lb S per ton of dry bark fuel for the first boiler, and from 5.9 to 8.2 lb S per ton of dry bark fuel for the second boiler, while the summary Figures 4.5 and 4.6 of Section 4 span an input range from 0 to about 50 lb S per dry ton of wood residue fired.

In Mill AE, a series of emission tests were carried out over a 20-day period in mid-2008 where varying amounts of TDF were cofired in a combination boiler with bark, natural gas, and small amounts of nonrecyclable recovered paper (NRP) fuel cubes. The grate-design boiler was equipped with a continuous emissions monitor (CEM) for SO_2. Fuel analyses showed the bark and NRP fuel cubes had similar low S contents (0.03 and 0.04%, respectively), while the TDF had about 2.15% S. Over the 20-day period, the heat inputs from the four different fuels were monitored carefully, averaging about 69.3%, 18.8%, 6.7% and 5.2% for the bark, gas, TDF and fuel cubes, respectively. Figure 5.1 shows the relationship between the lb S emitted and the lb S in total combined fuel, both per ton of dry bark fuel fired. For this analysis, the hourly average SO_2 CEM data were averaged for S input increments of 0.5 in the S input range of 0 to 5.5 lb S per ton of dry bark fired. In Figure 5.1, the regression lines obtained for the mill data are also compared with the regression lines representing the regression curves shown in Figures 4.5 and 4.6 covering the broader range of available S capture data. It is seen that at even this low level range of S input from TDF to the boiler, the data agree quite favorably with the relationships described in the previous section.

In Mill AF, three tests were conducted on each of two consecutive days in 2004, 2006 and 2008 in a spreader stoker unit equipped with an ESP where the TDF fraction of the bark-TDF fuel mixture varied in a narrow range from about 26 to 31% of total heat input. Table 5.1 provides selected data for this boiler for the 18 different runs, including the results of some fuel analysis.

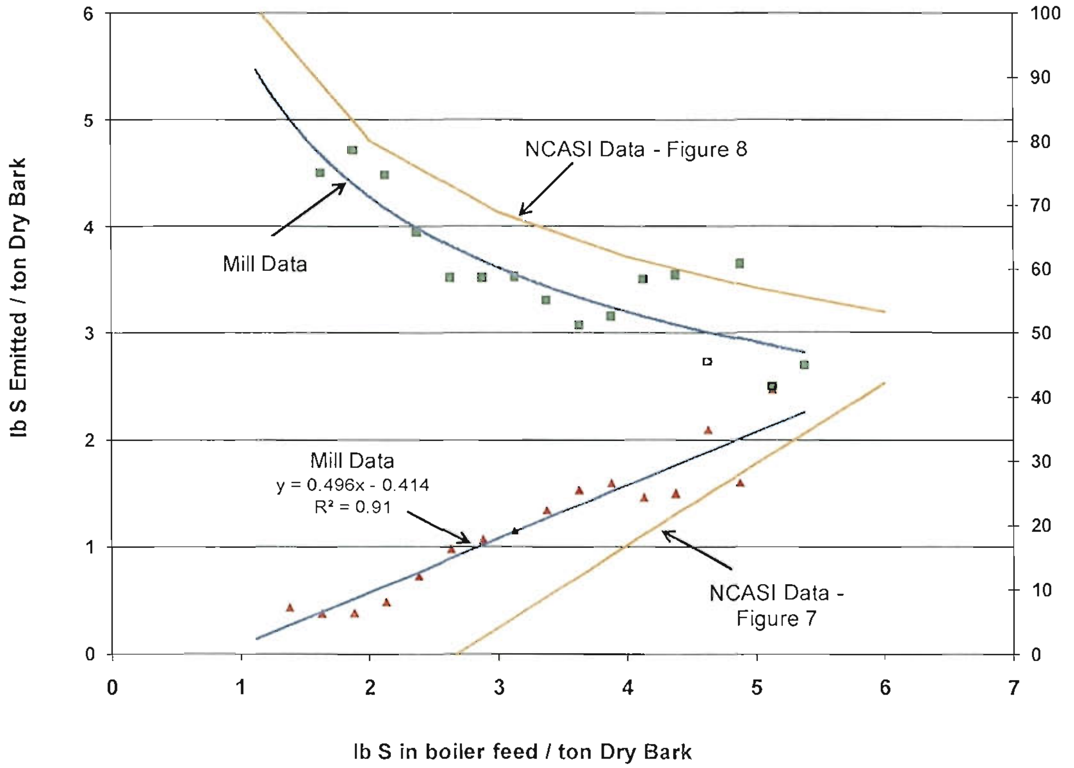

Figure 5.1 TDF S Capture in Mill AE Bark Boiler – NCASI Summary versus SO_2 Monitor Data

Table 5.1 Tire-Derived Fuel Firing in Mill AF Bark-Fired Boiler

				Estimated			% Heat Input From		Total, 10^6 Btu/hr	SO_2, lb/10^6Btu	
Test No.	Boiler Code	%S in TDF	%S in Bark	X, lb S to boiler/t dry bark	Y_2, % SO_2 reductn	Y_1, lb S emitted/t dry bark	Bark	TDF		Measured	Expected[1]
1	AF	1.55	0.030	6.71	62.3%	2.53	73.6	26.4	392.3	0.222	0.590
2	AF	1.55	0.030	6.71	64.2%	2.40	73.6	26.4	392.3	0.211	0.590
3	AF	1.55	0.030	6.71	63.3%	2.46	73.6	26.4	392.3	0.216	0.590
4	AF	1.55	0.030	5.92	44.6%	3.27	76.2	23.8	358.8	0.298	0.539
5	AF	1.55	0.030	5.92	44.4%	3.29	76.2	23.8	358.8	0.300	0.539
6	AF	1.55	0.030	5.92	46.7%	3.15	76.2	23.8	358.8	0.287	0.539
1	AF	1.55	0.030	6.61	59.7%	2.66	73.9	26.1	397.0	0.235	0.584
2	AF	1.55	0.030	6.70	54.5%	3.05	73.6	26.4	392.8	0.269	0.590
3	AF	1.55	0.030	6.70	41.1%	3.95	73.6	26.4	392.8	0.347	0.590
4	AF	1.55	0.030	6.92	47.2%	3.66	72.9	27.1	337.7	0.319	0.603
5	AF	1.55	0.030	6.92	43.6%	3.91	72.9	27.1	337.7	0.341	0.603
6	AF	1.55	0.030	6.23	52.4%	2.97	75.1	24.9	331.1	0.267	0.560
1	AF	1.55	0.030	7.56	58.9%	3.11	71.0	29.0	357.1	0.264	0.641
2	AF	1.55	0.030	7.62	55.7%	3.37	70.8	29.2	355.0	0.285	0.645
3	AF	1.55	0.030	7.65	57.5%	3.25	70.7	29.3	353.7	0.275	0.647
4	AF	1.55	0.030	8.19	59.1%	3.35	69.1	30.9	316.2	0.277	0.677
5	AF	1.55	0.030	8.19	58.1%	3.43	69.1	30.9	316.2	0.284	0.677
6	AF	1.55	0.030	8.16	57.8%	3.45	69.2	30.8	317.1	0.285	0.676

[1] TDF analysis in 1999 gave a range of 1.3 to 1.8% for S (average 1.55%) and a range of 15,000 to 15,500 Btu/lb for heat value (average 15,250 Btu/lb); Bark analysis of 11 samples in 2001 gave a range of 0.026 to 0.036% for S (average 0.030%) and a range of 8,219 to 8,588 Btu/lb for heat value (average 8,356 Btu/lb)

Figure 5.2 shows the relationship between the lb S emitted and the lb S in total combined fuel, both per ton of dry bark fuel fired. Even though the S input from TDF ranged from about 5.9 to only about 8.2, it is seen that the data for the Mill AF bark-TDF combination boiler agree quite favorably with the overall linear regression correlation derived in the previous section.

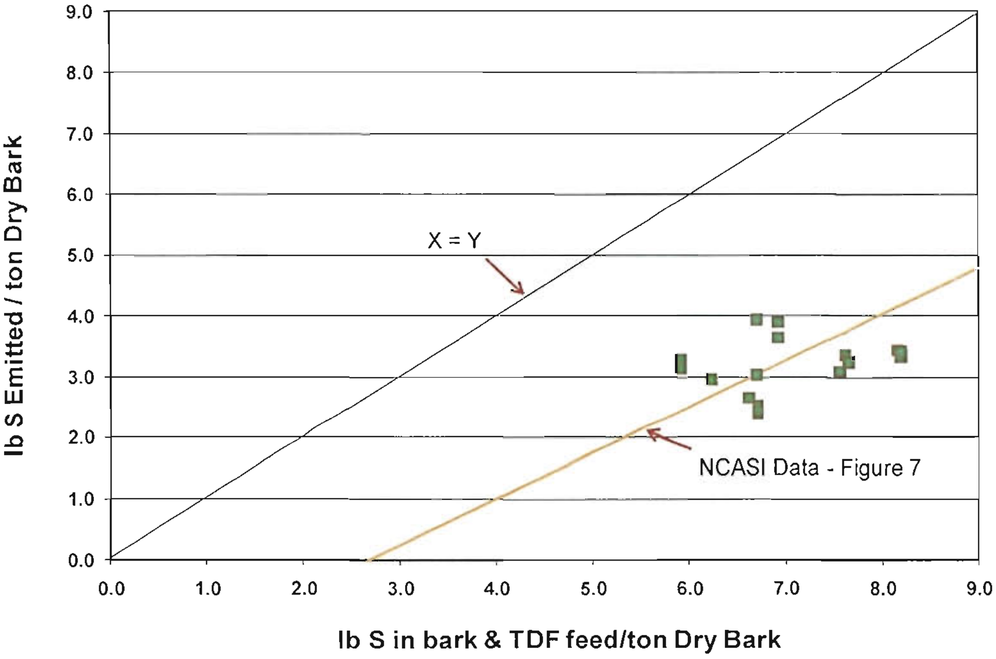

Figure 5.2 TDF S Capture in Mill AF Bark Boiler – NCASI Summary versus Stack SO_2 Data

6.0 SUMMARY AND CONCLUSIONS

A detailed review of the literature on sulfur capture in bark/wood residue or biomass-fired boilers and pilot/laboratory scale furnaces in which some sulfur-containing fuel or waste gas was also cofired was conducted. The literature and field study results generated by NCASI and individual mills show fuel sulfur retention in combination bark- or biomass-fired boilers is a phenomenon that is repeatedly observed. However, there are certain instances when such capture may indeed be insignificant. These instances typically involve large coal-fired utility boilers which burn small amounts (up to about 10%) of biomass or bubbling/circulating fluidized bed combustors (BFBCs and CFBCs). One suggested explanation for this discrepancy is that in the case of large coal-fired utilities and BFBC/CFBCs the unburned carbon levels in the fly ash are generally quite low, especially compared with ashes from predominantly wood/biomass-fired grate boilers. The activated-carbon-like wood/biomass fly ash characteristic is likely the main reason why sulfur retention occurs in such combination boilers.

Adsorption of SO_2 and O_2 on the activated-carbon-like combustion ash surface of bark/biomass-fired boilers, followed by oxidation of SO_2 to SO_3 on the same surface and subsequent reaction with adsorbed moisture (H_2O) to form H_2SO_4, is proposed as the plausible overall mechanism for sulfur capture. The presence of alkali metals in the bark/biomass ash would further assist the irreversible removal of SO_2 by reacting with the acid to form metal sulfates. However, as demonstrated in coal-fired utilities and BFBC/CFBCs, the reaction with alkali metals contained in the ash appears not to be the key initiating mechanism for sulfur capture.

A significant amount of sulfur capture data from the literature, from NCASI files, and from previous NCASI studies was used to further consolidate the correlations developed in an earlier study (Technical Bulletin No. 640) between the sulfur input to the boiler and the sulfur emitted from the boiler. The new correlation between Y, the lb S emitted per dry ton of bark or biomass fired and X, mass fired, is $Y = 0.758X - 2.0255$ with a coefficient of correlation $r^2 = 0.92$. A total of 101 data points were included in this correlation with the data coming from 14 combination boilers and one laboratory furnace. The biomass fuels included bark, wood residues, and straw while the sulfur-containing fuels included coal, fuel oil, tire-derived fuel and kraft pulp mill noncondensible gases.

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ATTACHMENT F

NSPS ANALYSIS FOR BURNING NO. 6 FUEL OIL IN NO. 4 COMBINATION BOILER

NSPS APPLICABILITY FOR PULP FIBER REJECT FIRING IN NO. 4 COMBINATION BOILER

To ensure we do not trigger NSPS for SO_2 when burning pulp fiber reject material in the No. 4 Combination Boiler, we will need to limit the maximum amount of No. 6 fuel oil fired to 2,604 gal/hr at 2.35% sulfur. This is 187.1 gal/hr less than the maximum burner firing rate of 2,791 gal/hr. This offsets 72.1 lb/hr of SO_2 emissions when burning a maximum of 6,660 lb/hr of the pulp fiber reject material (3.33 ton/hr or 80 tons/day). If we are essentially substituting pulp fiber rejects for bark, then we can assume no change in PM or NOx emissions, so burning the pulp fiber rejects under this scenario would not trigger NSPS. The mill will have to ensure that the combination of fuel oil, bark, and pulp fiber rejects does not exceed the rated heat input capacity of the boiler on an hourly basis. As long as the boiler isn't burning more than 53.7 tons/hr bark and 3.33 tons/hr pulp fiber reject material and 2,604 gal oil/hr, there will not be an increase in the maximum hourly emission rate for SO_2 emissions.

Oil firing equivalent to 72.1 lb SO_2/hr @ 2.35% S (see calculations below) = 0.164 (TV Permit factor) x 2.35% S x gal fuel oil/hr.

Gal fuel oil = 72.1 / (0.164 x 2.35) = 187.1 gal oil/hr
Maximum fuel oil firing rate = 418.6 MM Btu/hr burner design rate / 150,000 Btu/gal = 2,791 gal/hr
Restricted fuel oil firing rate to ensure no hourly increase in SO_2 emissions = 2,791 – 187.1 = **2,604 gal fuel oil/hr** = 390.6 MMBTU/hr

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Under the future operating scenario when the boiler is burning just bark and natural gas and pulp fiber reject material, the NSPS standard will be 0.2 lb/MM Btu (burning only gaseous fuel (nat. gas) plus any other fuel (bark+pulp fiber rejects)). The mill has to back-off an equivalent amount of bark, on a Btu basis, to burn the pulp fiber reject material. When doing this, the mixture of fuels has an SO_2 emission rate of ~ 0.15 lb/MM Btu, which is less than the NSPS standard of 0.2 lb/MM Btu:

Maximum burning rate of pulp fiber rejects = 80 tons/day = 3.33 tons/hr @ 3,389 Btu/lb (as fired) = 22.6 MM Btu/hr at 0.5412% S

Maximum bark firing rate in future = 564 MM Btu/hr @ 4,750 Btu/lb
Backing off an equivalent amount of bark to fire the pulp fiber rejects: 564 MM Btu/hr – 22.6 MM Btu/hr = 541.4 MM Btu/hr bark firing rate

SO_2 emissions from bark = 541.4 MM Btu/hr x 0.025 lb/MM Btu = 13.5 lb/hr
SO_2 emissions from pulp fiber rejects = 3.33 ton/hr x 2,000 lb/ton x 0.005412 S x 2 lb SO_2/lb S = 72.1 lb/hr

Total SO_2 emissions = 13.5 + 72.1 = 85.6 lb/hr
Total heat input (bark+pulp fiber rejects) = 564 MM Btu/hr

SO_2 emission rate = 85.6 lb/hr / 564 MM Btu/hr = **<u>0.15 lb/MM Btu < 0.2 lb/MM Btu</u>** NSPS standard (40 CFR 60.42b(k)).

ATTACHMENT G

Best Available Retrofit Technology Modeling Report

BEST AVAILABLE RETROFIT TECHNOLOGY EXEMPTION ANALYSIS UPDATE

GEORGIA-PACIFIC CONSUMER PRODUCTS LLC,

PALATKA, FL MILL

PREPARED MAY 20, 2009

1.0 INTRODUCTION

1.1. Overview of the Regional Haze BART Process

Under regional haze regulations, the Environmental Protection Agency (EPA) has issued final guidelines dated July 6, 2005 for Best Available Retrofit Technology (BART) determinations (70 FR 39104-39172). The regional haze rule includes a requirement for BART for certain large stationary sources, such as our pulp & paper facility in Palatka, Florida. Sources are BART-eligible if they meet three criteria concerning (1) potential emissions of visibility-impairing pollutants, (2) the date when the source was put in operation, and (3) whether they fall within one of the source categories listed in the guidance. The guidance requires a BART engineering evaluation using five statutory factors for any BART-eligible source that can be reasonably expected to cause or contribute to impairment of visibility in any Class I areas protected under the regional haze rule. (Note that, depending on the five factors, the evaluation may result in no control.) Air quality modeling is an important tool available to the States to determine whether a source can be reasonably expected to contribute to visibility impairment in a Class I area.

The process of making a BART determination consists of four steps:

> 1) Identify whether a source is "BART-eligible" based on its source category, when it was put in service, and the magnitude of its emissions of one or more "visibility-impairing" air pollutants. The BART guidelines list 26 source categories of stationary sources that are BART-eligible. Sources must have been put in service between August 7, 1962 and August 7, 1977. Finally, a source is eligible for BART if potential emissions of visibility-impairing air pollutants are greater than 250 tons per year. Qualifying pollutants include primary particulate matter (PM_{10}) and gaseous precursors to secondary fine particulate matter, such as SO_2 and NO_x. VISTAS has determined that neither ammonia nor volatile organic compounds (VOCs) should be included as visibility-impairing pollutants for BART eligibility.
>
> 2) Determine whether a BART-eligible source can be excluded from BART controls by demonstrating that the source cannot be reasonably expected to cause or contribute to visibility impairment in a Class I area. The preferred approach is an assessment with an air quality model such as CALPUFF or other appropriate model followed by comparison of the estimated 24-hr visibility impacts against a threshold above estimated natural conditions to be determined by the States.[1] The threshold to determine whether a single source "causes" visibility impairment is set at 1.0 deciview (dv) change from natural conditions over a 24-hour averaging period in the final BART rule (70 FR 39118). The guidance also states that the proposed

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[1] Guidance to determine the level of the natural conditions baseline for BART modeling purposes is still under development by VISTAS member states and EPA Region IV.

threshold at which a source may "contribute" to visibility impairment should not be higher than 0.5 dv although, depending on factors affecting a specific Class I area, it may be set lower than 0.5 dv. The test against the threshold is "driven" by the contribution level, since if a source "causes", by definition it "contributes".

3) Determine BART controls for the source by considering various control options and selecting the "best" alternative, taking into consideration:

a) Any pollution control equipment in use at the source (which affects the availability of options and their impacts),
b) The costs of compliance with control options,
c) The remaining useful life of the facility,
d) The energy and non air-quality environmental impacts of compliance, and
e) The degree of improvement in visibility that may reasonably be anticipated to result from the use of such technology.

If a source agrees to apply the most stringent controls available to BART-eligible units, the BART analysis is essentially complete and no further analysis is necessary (70 FR 39165).

4) Incorporate the BART determination into the State Implementation Plan for Regional Haze, which is due by December 2007.

Step 2 described above reflects 40 CFR Part 51 Appendix Y which states that, "*You can use dispersion modeling to determine that an individual source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area and thus is not subject to BART.*" (70 FR 39162) This "individual source attribution approach" determines if a BART-eligible source (*i.e.,* collection of eligible emission units at a source) is predicted to cause or contribute to visibility impairment in a Class I area. As mentioned above, a predicted impact of 1.0 dv change or more is considered to "cause" visibility impairment, and a predicted impact of 0.5 dv change or more is considered to "contribute". Any source determined to cause or contribute to visibility impairment in any Class I area is subject to BART and will also complete additional visibility impact analyses.

1.2. Organization of the Report

Section 2 presents facility-specific information. Section 3 presents the contribution by VISTAS for the BART analyses. Section 4 summarizes the modeling approach, and model configuration. Section 5 presents the criteria and processing of model results to demonstrate what impairment, if any, the facility is predicted to create in the Class I areas.

2.0 SITE DESCRIPTION AND EMISSION INVENTORY

GP operates the Palatka Mill in Palatka (Putnam County) near the St. Johns River. The facility manufactures a variety of kraft paper products including paper towels and tissues. The facility is located in a lightly-developed area, and few residential areas are near the Mill. The Mill is located along Rice Creek on Putnam County Road 216. The area surrounding the facility includes a creek floodplain, and swamp land. Figure 1 depicts the location of the Mill and illustrates the adjacent terrain.

The potentially BART-eligible emission units are summarized in Table 1.

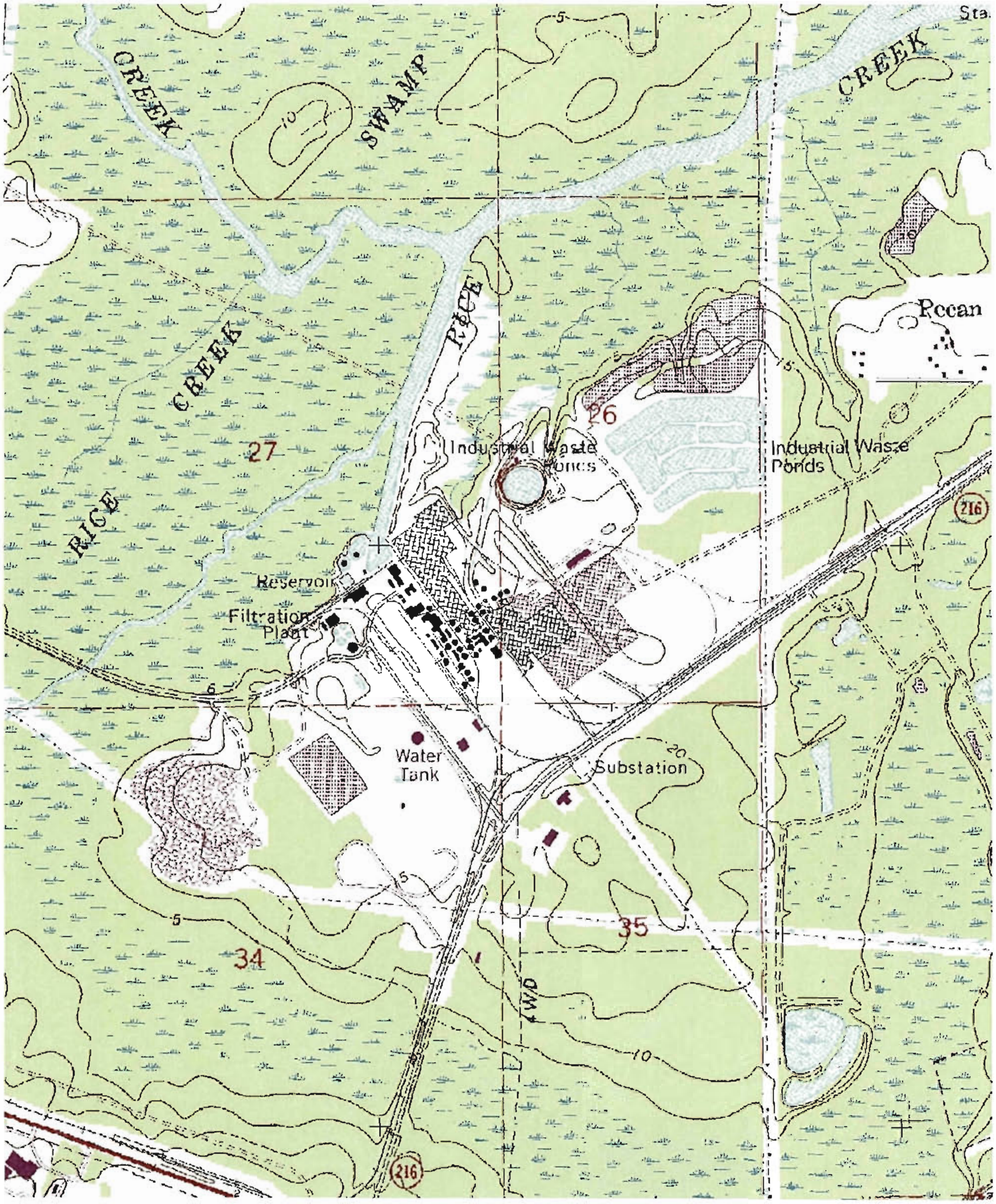
Table 1. Model Parameters for Potentially BART-Eligible Sources at GP Palatka

ID	Source Description	Stack Ht (Ft)	UTM NAD27 (m) East	UTM NAD27 (m) North	Stack Diameter (Ft)	Exit Velocity (Ft/Sec)	Exit Temp (deg F)
RB4	Recovery Boiler No. 4	230	433897	3283459	12	65.9	425
SDT4	Smelt Tank No. 4	206	433950	3283499	5	34.0	180
PB5	Power Boiler No. 5 (gas)	157	433954	3283487	9	53.7	500
CB4	Combination Boiler No. 4	237	433998	3283471	8	92.3	466
LK4	Lime Kiln No. 4	131	434122	3283268	4.4	70.6	164

The combustion sources currently operate with a variety of fuels as stated below:

- Power Boiler No. 5 combusts natural gas and may burn high volume, low concentration gases from the pulping operations.
- Combination Boiler No. 4 is permitted to burn bark/woodwaste, natural gas, noncondensible gases and high volume, low concentration gases from the pulping operations. The Mill proposes to also burn fiber rejects in this unit.
- Recovery Boiler No. 4 recovers pulping chemicals by burning black liquor solids and No. 6 oil.
- Lime Kiln No. 4 fires No. 6 oil and lime mud.

Figure 1. Topographical Map Georgia-Pacific Palatka Mill Vicinity



The modeling analysis applied the following assumptions to the existing fuels and control devices that reflect a proposed operating scenario:

1. Remove No. 6 Oil from Combination Boiler No. 4 and replace with natural gas or the equivalent to achieve the same emissions.

2. Apply flue gas recirculation, low-NOx burners, and overfire air controls or the equivalent to Combination Boiler No. 4 and reduce potential emissions to approximately 0.28 lb NOx/MMBtu (exclusive of the pulp mill gases).

3. With Power Boiler No. 5 burning gas only, remove the existing ESP and apply Low NOx Burners and Flue Gas Recirculation or the equivalent as necessary to achieve 0.125 lb NOx/MMBtu.

4. Analyze only normal operations. SOG and NCG gases are only combusted in the Combination Boiler when the Mill incinerator is malfunctioning. As discussed with the Department, normal operations do not include SO_2 from the combustion of SOG/NCGs in the Combination Boiler.

5. As part of a May 2009 permit application, SO_2 emissions from Combination Boiler No. 4 will reflect the potential emission rate from burning gas, bark and pulp fiber rejects.

The Palatka Mill reserves the right to shut down an emission unit in lieu of the proposed emission controls. For example, as we await regulatory approval for a larger natural gas pipeline, should shutting down Power Boiler 5 be preferred, we would remove all emissions from the source.

Table 2 presents revised fuel-specific speciation profiles and worst case 24-hr actual emissions applying these assumptions. Note that Combination No. 4 currently does not burn gas, and future emission rates reflect the use of burner/NOx control vendor emission estimates and mass balance for SO_2. The Appendix presents additional information on the speciation of emissions for the recovery boiler, lime kiln and smelt dissolving tank.

Table 2. Summary of Modeled Emission Rates for Proposed Fiber Reject Combustion, GP Palatka

		Maximum Actual 2001-2003 24-hr Average Emissions (lb/hr)				
Model Species Name	Particle Diameter (um)	RB4 Recovery Boiler	LK4 Lime Kiln	SDT4 Smelt Tank	CB4 Comb. Boiler 4 (a)	PB5 Power Boiler 5 (b)
SO_2	NA	109.9(c)	10.9(c)	7.32	167.6	0.31
NOx	NA	168.5(c)	50.3(c)	15.1	143.6	71.1
SO_4	0.5 – 1.0	3.17	0.70	0.02	0.51	0.15
NO_3	NA	4.35	0.40	0.33	0	0
SOA	0.5 – 1.0	1.49	0.10	0.206	7.32	2.74
PMC800	6.00 - 10.00	4.02	0.042	0.188	1.15	0
PMC425	2.50-6.00	6.44	0.93	1.21	1.15	0
PMF187	1.25-2.50	7.08	1.04	2.30	3.66	0
PMF112	1.00-1.25	3.94	0.578	1.14	3.66	0
PMF087	0.625-1.00	5.71	2.33	2.07	3.66	0.45
PMF063	0.50-0.625	13.20	5.15	5.00	3.66	0.45
EC187	1.25-2.50	0.0018	0.043	0.096	0.37	0
EC112	1.00-1.25	0.0010	0.024	0.047	0.37	0
EC087	0.625-1.00	0.0014	0.097	0.081	0.37	0.032
EC063	0.50-0.625	0.0033	0.214	0.21	0.37	0.032

(a) Speciation for PM species less than 2.5 um equally divides the mass into the four sub-category sizes
(b) Speciation for all PM species equally divides the mass into two sub-category sizes
(c) Emissions limited by Air permit 1070005-058-AV

The PSD Class I Areas (where visibility is an air quality related value) within 300 kilometers (km) of the Mill are:

1. Okefenokee- 109 km
2. Chassahowitzka – 139 km
3. Wolf Island – 184 km
4. St. Marks – 226 km

3.0 VISTAS CONTRIBUTION TO CALPUFF MODELING

For this application of BART Modeling, VISTAS and FDEP have the following data bases developed by TRC available:

- VISTAS version of the CALPUFF modeling system (version 5.7.56), maintained on the Earth Tech website.
- 4-km CALMET output files for 2001, 2002, and 2003 produced as described in the VISTAS Common Protocol.
- CALMET with a software modification to allow the meteorological data inputs into CALMET to be used to generate finer grid CALMET files without having to go back to the original MM5 output files

4.0 MODEL DISCUSSION

4.1 General Procedures

For sources subject to a full BART engineering analysis, GP is beginning with the most refined dataset available from VISTAS. The fine grid analyses will use the 98th percentile impact value for the 24-hr average at each Class I area. The analysis will use either the 8th highest day in each year or the 22nd highest day in the 3-year period, whichever is more conservative.

The VISTAS Common Modeling Protocol consistently recommends conservative assumptions. Individual States ultimately have responsibility to determine which, if any, BART controls are recommended in their State Implementation Plans (SIPs). The VISTAS protocol presents additional detailed information on the meteorological fields, and specific settings for CALPUFF and CALPOST (see section 4.33 of the VISTAS Common Modeling Protocol).

The analysis was performed in the following sequence for 2001, 2002 and 2003 individually:

Step 1. CALPUFF (Version 5.7.56)

Produce raw concentration files by executing CALPUFF for the five emission units together with the 16 species identified above for the individual years.

CALPUFF result files use the "PF" prefix

Step 2. POSTUTIL (Version 1.52)

Execute POSTUTIL for each of the 3 concentration files from Step 1 individually and transform the CALPUFF species to the following:

1. SO2
2. NOx
3. SO4
4. EC
5. SOA
6. PMC
7. SOIL (to be treated as PMF in the next processing step)

POSTUTIL result files use the "PU" prefix

Step 3. CALPOST (Version 5.6393)

Execute CALPOST for each of the four Class I Areas with the total concentration file from Step 3.

CALPOST result filenames use the "PS" prefix.

Note that the model results were not processed with ammonia-limited method options or the 2006 IMPROVE equation.

4.2 CALPUFF Configuration

Source emissions should be defined using the maximum 24-hour actual emission rate during normal operation for the most recent 3 or 5 years. If maximum 24-hr actual emissions are not available, continuous emissions data, permit allowable emissions, potential emissions, and emissions factors from AP-42 source profiles may be used as available. Specific configuration settings presented in the VISTAS Common Modeling Protocol are listed below:

- Use default data provided by VISTAS for background concentrations of SO_4 and total NO_3 ($HNO_3 + NO_3$).
- Use hourly ozone data as the background ozone input as prepared by VISTAS. The dataset includes monthly average values to use a substitute values (parameter "BKO3").
- Use the Pasquill-Gifford dispersion method.
- In CALPOST, use Method 6 with monthly average RH for calculating extinction, as recommended by the EPA.

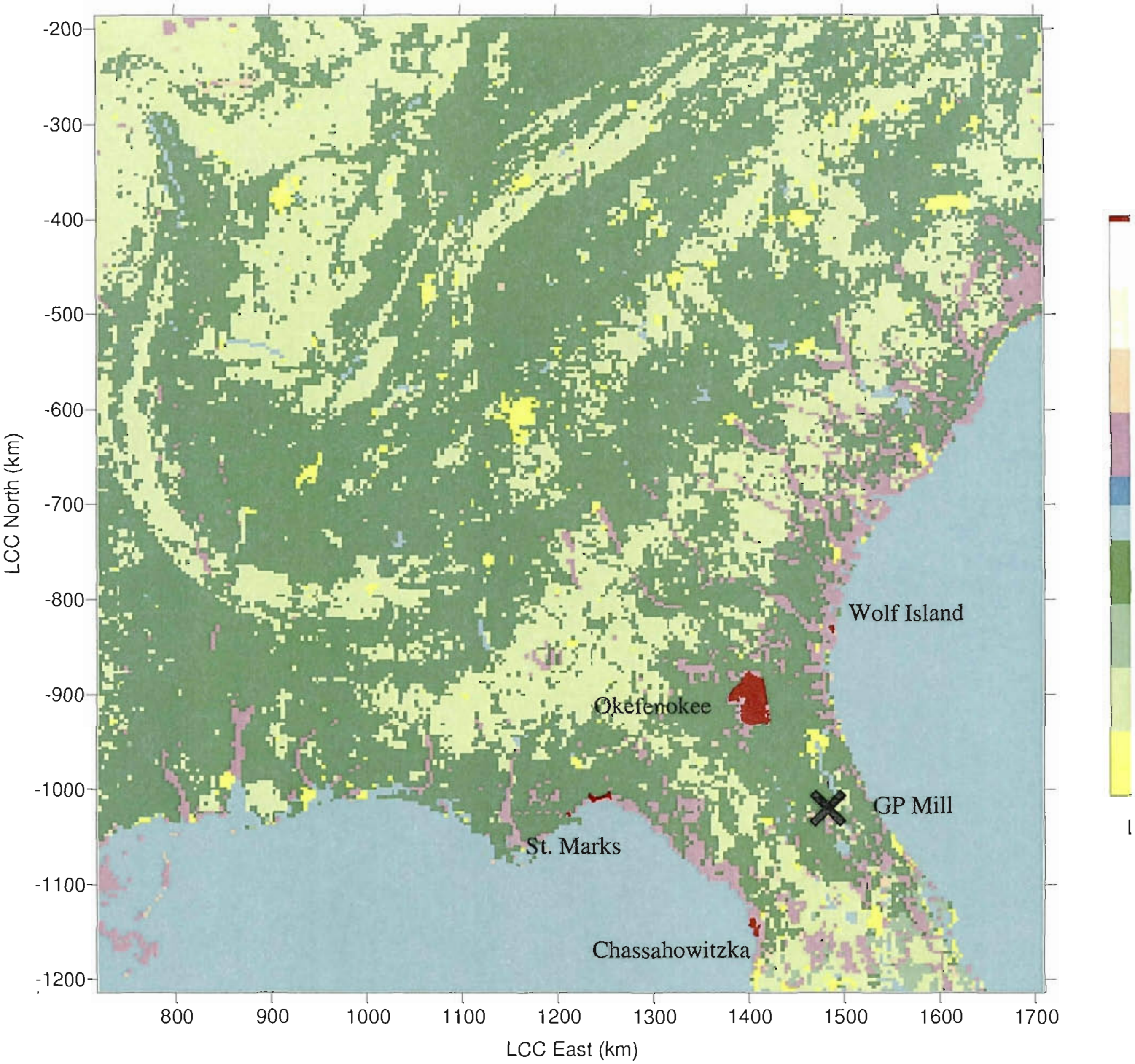
- Use EPA default calculations of light extinction under average background conditions.

The major features and options of the meteorological and dispersion model are summarized and discussed in the VISTAS Common Modeling Protocol.

As also discussed in the VISTAS Common Modeling Protocol, CALPUFF is currently not recommended for addressing visibility impacts from VOC because its capability to simulate secondary organic aerosol formation from VOC emissions is not adequately tested, especially for anthropogenic emissions. (Separately, condensable organic carbon can be calculated from PM10.)

GP completed the analysis with the Domain #4 4-km meteorological datasets provided by VISTAS which covers from approximately south of Orlando, FL to north of the Georgia-Tennessee state border. Figure 2 presents the modeling domain, the Class I Area model receptors and Palatka Mill. VISTAS Domain #2 is an alternate domain that is also satisfactory to cover the modeling area of interest.

Figure 2. CALPUFF Modeling Domain, Source and Receptors, GP Palatka BART Analyses



5.0 RESULTS AND DETERMINATION OF IMPAIRMENT

5.1 Impact Threshold

The final BART guidance recommends a threshold value of 0.5 dv change from natural conditions to define whether a source "contributes" to visibility impairment(although states may set a lower threshold). The 98th percentile (8th highest annual) 24-hr average predicted impact at the Class I area, as calculated using CALPOST Method 6 (monthly average relative humidity values), is to be compared to this contribution threshold value. For this comparison, the predicted impact at the Class I area on any day is taken to be the highest 24-hr average impact at any receptor in the Class I area on that day. (Note that the receptor where the highest impact occurs can change from day to day.) According to clarification of the BART guidance received from EPA, for a three-year simulation the modeling values to be compared with the threshold are the greatest of the three annual 8th highest values or the 22nd highest value over all three years combined, whichever is greater. CALPUFF presents the visibility change in both a % change and a dv change form.

5.2 Presentation of Modeling Results

Table 3 summarizes the CALPOST result for the predicted 98th percentiles change in visibility (dv) for each year and each Class I Area. The CALPOST output files contain additional information for speciation of these predicted impacts.

As shown, the 98th-percentile predicted impact for all datasets is below the 0.5 dv criteria.

Table 3. 98th Percentile Maximum Predicted Visibility Impact for 2001-2003, GP Palatka Mill

	Model Year			Model Year		
	2001	2002	2003	2001	2002	2003
	Okefenokee NWR			Wolf Island		
Delta DV – 98th percentile	0.3	0.2	0.2	0.1	0.1	0.1
Julian Day	278	365	247	177	22	190
Receptor #	265	219	216	721	722	716
	Chassahowitzka			St. Marks		
Delta DV – 98th percentile	0.2	0.2	0.2	0.1	0.1	0.1
Julian Day	297	297	280	127	297	268
Receptor #	214	214	209	2	1	101

APPENDIX

PARTICULATE MATTER SPECIATION CALCULATIONS

PM Speciation Analysis

NCASI Corporate Correspondence CC 06-021: Information on Kraft Pulp Mill Particulate Emissions for Visibility Modeli

NDCE Recovery Furnace

Total Filterable PM10 (lb/hr)	40.40	lb/hr	
BLS Firing Rate (ton BLS/hr)	100.00	ton BLS/hr	
Implied Filterable PM10 Emission Factor	0.4040	lb/ton BLS	NCASI Mean: 0.326
Filterable PM10/Filterable TSP	50.2%		
Filterable PM2.5/Filterable TSP	37.2%		
Filterable Coarse PM10-2.5 Emission Rate (lb/hr)	10.46	PMC	
Filterable Total PM2.5 Emission Rate (lb/hr)	29.94	lb/hr	
Elemental Carbon	0.00748	EC	
Filterable PM2.5 Emission Rate (lb/hr)	29.93	PMF	
Filterable Checksum	0.00	lb/hr	
Total CPM	0.090	lb/ton BLS	NCASI Range: 0.05-0.15
Total CPM Emission Rate (lb/hr) based on BLS firing	9.00	lb/hr	
Organic CPM/Total CPM	16.5%		
Inorganic CPM as Sulfate/Total CPM	35.2%		
Inorganic CPM non-Sulfate/Total CPM	48.3%		
Organic Aerosol Emission Rate (lb/hr)	1.49	SOA	
Sulfate Emission Rate (lb/hr)	3.17	SO4	
Inorganic non-Sulfate Aerosol Emission Rate (lb/hr)	4.35	PIC as NO3	
Total PM10 Emission Rate (lb/hr)	**49.40**	**lb/hr**	
Total PM10 Checksum	0.00	lb/hr	

Size (PM_)	Filterable	PMC	PMF	EC	SOA	SO4
800 (10-6.0)	5.0%	4.02				
425 (6.0-2.5)	8.0%	6.44				
187 (2.5-1.25)	8.8%		7.08	0.00177		
112 (1.25-1.0)	4.9%		3.94	0.00099		
087 (1.0-0.625)	7.1%		5.71	0.00143	0.74	1.58
063 (<0.625)	16.4%		13.20	0.0033	0.74	1.58
Total	**50.2%**	**10.46**	**29.93**	**0.0075**	**1.49**	**3.17**

SAM = 0.032

PM Speciation Analysis

NCASI Corporate Correspondence CC 06-021: Information on Kraft Pulp Mill Particulate Emissions for Visibility Modeling (October 22, 2006).

Smelt Dissolving Tank

Total Filterable PM10 (lb/hr)	12.34	lb/hr	From change in PM with 81.9% factor
BLS Firing Rate (ton BLS/hr) associated with Increase	100.00	ton BLS/hr	For 2007-2008 period
Implied Filterable PM10 Emission Factor	0.12	lb/ton BL NCASI Mean: 0.121	

Filterable PM10/Filterable TSP	81.9%
Filterable PM2.5/Filterable TSP	72.6%

Filterable Coarse PM10-2.5 Emission Rate (lb/hr)	1.40	PMC
Filterable Total PM2.5 Emission Rate (lb/hr)	10.94	lb/hr
Elemental Carbon	0.438	EC
Filterable PM2.5 Emission Rate (lb/hr)	10.50	PMF
Filterable Checksum	0.00	lb/hr

Total CPM	0.0074	lb/ton BL NCASI Range: 0.002-0.015
Total CPM Emission Rate (lb/hr) based on BLS firing	0.74	lb/hr
Organic CPM/Total CPM	27.8%	
Inorganic CPM as Sulfate/Total CPM	27.3%	
Inorganic CPM non-Sulfate/Total CPM	44.9%	
Organic Aerosol Emission Rate (lb/hr)	0.21	SOA
Sulfate Emission Rate (lb/hr)	0.20	SO4
Inorganic non-Sulfate Aerosol Emission Rate (lb/hr)	0.33	PIC as NO3

Total PM10 Emission Rate (lb/hr)	**13.08**	**lb/hr**
Total PM10 Checksum	0.00	lb/hr

Size (PM_)	Filterable	PMC	PMF	EC	SOA	SO4	NO3	Total
800 (10-6.0)	1.2%	0.19						0.19
425 (6.0-2.5)	8.1%	1.21						1.21
187 (2.5-1.25)	15.9%		2.30	0.10				2.39
112 (1.25-1.0)	7.9%		1.14	0.047				1.18
087 (1.0-0.625)	14.3%		2.07	0.09	0.10	0.10	0.17	2.52
063 (<0.625)	34.6%		5.00	0.21	0.10	0.10	0.17	5.58
Total	**81.9%**	**1.40**	**10.50**	**0.438**	**0.21**	**0.20**	**0.33**	**13.08**

SAM = 0.002 lbs SAM/ton BLS

Lime Kiln With Wet Scrubber

Stack Test = 12..34 lb PM/hr RM5

								condensable spli	
	total	filterable PM	condensable		filterable			inorganic	
					PM$_{10}$	PM$_{2.5}$		H$_2$SO$_4$	non-sulfate
%		91.1%	8.9%		84.7%	76.8%		58.2%	33.5%
(lb/hr)	**13.547**	**12.34**	**1.207**	(lb/hr)	**10.452**	**9.477**		**0.702**	**0.404**

	FILTERABLE								**CONDENS**	
						fine filterable[2]				
	CALPUFF Code	Diameter (μm)	filterable (% of PM)	filterable (lb/hr)	coarse filterable inorganic (lb/hr)	inorganic - 96.0% of PM$_{2.5}$ filterable (lb/hr)	carbon - 4.0% of PM$_{2.5}$ filterable (lb/hr)		H$_2$SO$_4$[3] (lb/hr)	organic condensable[3] (lb/hr)
	PM800	6.00 - 10.00	0.3%	0.042	**0.042**					
	PM425	2.50-6.00	7.6%	0.932	**0.932**					
	PM187	1.25-2.50	8.8%	1.086		**1.042**	**0.0434**			
	PM112	1.00-1.25	4.9%	0.602		**0.578**	**0.0241**			
	PM087	0.625-1.00	19.7%	2.429		**2.331**	**0.0971**		**0.351**	**0.050**
	PM063	0.50-0.625	43.4%	5.360		**5.146**	**0.2144**		**0.351**	**0.050**
total			**84.7%**	**10.452**	**0.975**	**9.098**	**0.3791**		**0.702**	**0.100**
					PMC	**SOIL**	**EC**		**H$_2$SO$_4$**	**SOA**
Ext. coefficient					0.6	1	10		3*f(RH)	4
Explanation of cell colors										
blue - user supplied data	**green - default entry is calculated - could also be user supplied data**								**brown - calculated data**	

[1] Assumed nitrate comprises all of the non-sulfate inorganic CPM fractions. Sulfate and nitrate have the same extinction efficiency (3.0) and the same dependence on rel
terms of modeling for visibility using the CALPUFF model, they will behave the same way. This assumption is conservative since in reality some of the nitrate may bec
atmosphere, depending on temperature, relative humidity and availability of ammonia. However, as a first step, the assumption of all inorganic condensable PM as nitra
Primary NO$_3$ should not be categorized as soil, because soil is non-hygroscopic with lower extinction efficiency (1.0). If the assumption of all inorganic CPM as nitrate
it may be possible to conduct tests with the model to explore whether the NO$_3$ can be properly entered as a primary (emitted) pollutant

PAL Power Blr 5 with Gas

Natural Gas Combustion

	Fuel Use	0.50813725	MMscf/hr							
								condensable split		
	total	filterable PM	condensable		filterable			inorganic		organic
					PM$_{10}$	PM$_{2.5}$		H$_2$SO$_4$	non-sulfate	
%		25.0%	75.0%		100.0%	100.0%		5.3%	0.0%	94.7%
(lb/hr)	3.862	0.965	2.896	(lb/hr)	0.965	0.965		0.152	0.000	2.744

	FILTERABLE						CONDENSABLE			
					fine filterable[2]					
CALPUFF Code	Diameter (µm)	filterable (% of PM)	filterable (lb/hr)	coarse filterable inorganic (lb/hr)	inorganic - 93.3% of PM$_{2.5}$ filterable (lb/hr)	carbon - 6.7% of PM$_{2.5}$ filterable[3] (lb/hr)	H$_2$SO$_4$[2] (lb/hr)	organic condensable[3] (lb/hr)	non-sulfate inorganic condensable[3] (lb/hr)	Diameter (µm)
PM800	6.00 - 10.00	0.0%	0.000	0.000						6.00 - 10.00
PM425	2.50-6.00	0.0%	0.000	0.000						2.50-6.00
PM187	1.25-2.50	0.0%	0.000							1.25-2.50
PM112	1.00-1.25	0.0%	0.000							1.00-1.25
PM087	0.625-1.00	50.0%	0.483		0.450	0.0323	0.076	1.372	0.000	0.625-1.00
PM063	0.50-0.625	50.0%	0.483		0.450	0.0323	0.076	1.372	0.000	0.50-0.625
total		100.0%	0.965	0.000	0.901	0.0647	0.152	2.744	0.000	
				PMC	SOIL	EC	H$_2$SO$_4$	SOA	NO$_3$	
Ext. coefficient				0.6	1	10	3*f(RH)	4	3*f(RH)	

Explanation of cell colors

blue - user supplied data **green - default entry is calculated - could also be user supplied data** **brown - calculated data**

1. Assumed all PM is < 1 micron for natural gas combustion.
2. Assume that 1/3 SO2 converts to sulfate and the remainder is organic. This is the assumption for natural gas combustion turbines.
3. Used 6.7% for EC based on EPA Black Carbon Report Table 6.
4. Uniformly distributed PM2.5 and EC between size categories.
5. The organic CPM, sulfate CPM and non-sulfate CPM emissions are assumed to be equally distributed in the particle size ranges of 0 to 0.625 µm and 0.625 to 1.0 µm

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM$_{10}$, PM$_{2.5}$ or PM$_1$ emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particula matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

Wood Combustion with ESP

	Heat Input	**460.6**	MMBtu/hr								
									condensable split		
	total TSP	filterable TSP	condensable			filterable			inorganic		organ
						PM$_{10}$	PM$_{2.5}$		H$_2$SO$_4$[1]	non-sulfate[2]	
%		76.1%	23.9%			74.1%	64.8%		6.5%	0.0%	93.5
(lb/hr)	**32.703**	**24.872**	**7.830**		(lb/hr)	**18.424**	**16.121**		**0.512**	**0.000**	**7.31**

			FILTERABLE								**CONDENSABLE**
						fine filterable[4]					
	CALPUFF Code	Diameter (μm)	filterable (% of PM)	filterable (lb/hr)	coarse filterable inorganic (lb/hr)	inorganic - 90.7% of PM$_{2.5}$ filterable (lb/hr)	carbon - 9.3% of PM$_{2.5}$ filterable[3] (lb/hr)		H$_2$SO$_4$[5] (lb/hr)	organic condensable[5] (lb/hr)	non-sul inorga condens (
	PM800	6.00 - 10.00	4.6%	1.152	**1.152**						
	PM425	2.50-6.00	4.6%	1.152	**1.152**						
	PM187	1.25-2.50	16.2%	4.030		**3.655**	**0.3748**				
	PM112	1.00-1.25	16.2%	4.030		**3.655**	**0.3748**				
	PM087	0.625-1.00	16.2%	4.030		**3.655**	**0.3748**		**0.256**	**3.659**	**0.00**
	PM063	0.50-0.625	16.2%	4.030		**3.655**	**0.3748**		**0.256**	**3.659**	**0.00**
total			**74.1%**	**18.424**	**2.303**	**14.622**	**1.4993**		**0.512**	**7.318**	**0.00**
					PMC	**SOIL**	**EC**		**H$_2$SO$_4$**	**SOA**	**NO$_3$**
Ext. coefficient					0.6	1	10		3*f(RH)	4	3*f(R

Explanation of cell colors

blue - user supplied data

green - default entry is calculated - could also be user supplied data

brown - calculated data

1. Sulfate estimated from 4.45% of SO2. Estimate is based on fuel oil firing data from AP-42 Section 1.4. (SO2 = 157S; SO3 = 5.7S. SO3=5.7/157

Convert SO3 to H2SO4 = 3.63%*98/80 = 4.45%)

2. Assume no non-sulfate inorganic condensables.

3. Used 9.3% for EC based on EPA Black Carbon Report Table 6.

4. Uniformly distributed PM10, PM2.5 and EC between size categories.

5. The organic CPM, sulfate CPM and non-sulfate CPM emissions are assumed to be equally distributed in the particle size ranges of 0 to 0.625 μm and 0.625 to 1.0 μm

ATTACHMENT H

PSD NETTING TABLEs

TABLE 1
CONTEMPORANEOUS AND DEBOTTLENECKING EMISSIONS ANALYSIS AND PSD APPLICABILITY
INCORPORATION OF NO. 5 POWER BOILER FIRING 100% NATURAL GAS AND NO. 4 COMBINATION BOILER FIRING NATURAL GAS IN LIEU OF NO. 6 FUEL OIL

Source	Pollutant Emission Rate (TPY)										
Description	**SO_2**	**NO_x**	**CO**	**PM**	**PM_{10}**	**VOC**	**TRS**	**SAM**	**Lead**	**Mercury**	**Fluoride**
Future Potential Emissions											
No. 4 Combination Boiler - worst-case beween firing natural gas or bark or pulp fiber reject material [a]	137.8	485.1	1,010.5	80.8	59.8	40.4	---	6.0	0.1	0.002	---
Past Actual Emissions											
No. 4 Combination Boiler [b]	820.4	413.2	780.3	99.2	71.9	22.4	--	--	0.065	0.0047	0.084
Total- Past Actual	**820.4**	**413.2**	**780.3**	**99.2**	**71.9**	**22.4**	--	**36.1**	**0.065**	**0.0047**	**0.084**
Increase Due to Project	**-682.6**	**71.9**	**230.2**	**-18.4**	**-12.1**	**18.0**	--	**-30.1**	**0.035**	**-0.0027**	**-0.084**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0.6	0.1	3.0
Netting Triggered?	No	**Yes**	**Yes**	No	No	No	No	No	No	No	No
CONTEMPORANEOUS EMISSION CHANGES											
No. 5 Power Boiler firing 100% natural gas [c]	-3,314.9	-148.1	412.1	-174.7	-147.6	11.0	--	-145.9	-0.01352	-0.000457	-0.365
Total Contemporaneous Emission Changes	**-3,314.9**	**-148.1**	**412.1**	**-174.7**	**-147.6**	**11.0**	--	**-145.9**	**-0.01352**	**-0.000457**	**-0.365**
TOTAL NET CHANGE*	**-3,997**	**-76**	**642**	**-193**	**-160**	**29**	--	**-176**	**0.02**	**-0.003**	**-0.4**
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

Notes:

[a] Total future potential emissions from Attachment A-Permit Application Forms

[b] Based on average of 2004-2005 emission rates (see Table 2-1 from August 2006 PSD Application)

[c] Based on difference between future potential emission rates buring 100% natural gas and past actual (average of 2004-2005 emission rates) burning 100% No. 6 fuel oil-see attached Table 1-PSD Netting Table

Previously permitted "Pollution Control Projects" have been removed from this updated netting table, as well as those projects that are no longer in the 5-year contemoraneous period. This includes the MACT I Cluster Rule project implemented in 2002 (Phase I) and the Brown Stock Washer (Phase II-MACT I) project implemented in February 2006, the shutdown of the No. 4 Power Boiler (September 2003), and the No. 7 Package Boiler (October 2002)

TABLE 1
CONTEMPORANEOUS AND DEBOTTLENECKING EMISSIONS ANALYSIS AND PSD APPLICABILITY
INCORPORATION OF NO. 5 POWER BOILER FIRING 100% NATURAL GAS
AND NO. 4 COMBINATION BOILER FIRING NATURAL GAS IN LIEU OF NO. 6 FUEL OIL

Source	Pollutant Emission Rate (TPY)										
Description	SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluoride
Future Potential Emissions											
No. 4 Combination Boiler - worst-case beween firing natural gas or bark [a]	50.5	485.1	1,010.5	80.8	59.8	40.4	---	2.2	0.097	0.0071	0.0
No. 5 Power Boiler firing 100% natural gas [b]	1.5	311.5	461.0	18.9	18.9	13.7	---	0.0	1.25E-03	6.48E-04	0.0
No. 4 Lime Kiln: annual: 20 ppmvd TRS	40.0	297.4	71.5	130.2	128.0	41.4	25.1	1.8	0.25	--	--
No. 4 Recovery Boiler	153.9	738.1	2,245.6	331.1	248.3	92.0	34.2	15.9	0.014	8.3E-05	--
No. 4 Smelt Dissolving Tank	33.7	69.6	11.4	55.2	49.7	115.0	14.9	--	0.013	8.3E-05	--
Black Liquor/Green Liquor Tanks	--	--	--	--	--	14.0	3.7	--	--	--	--
Caustic Area	--	--	--	2.6	2.6	18.9	5.8	--	--	--	--
Other Projects											
Bark Handling System	--	--	--	22.8	13.9	475.8	--	--	--	--	--
Total- Future Potential	**279.6**	**1,901.6**	**3,800.0**	**641.7**	**521.3**	**811.2**	**83.7**	**19.9**	**0.38**	**0.0079**	**0.000**
Past Actual Emissions											
No. 5 Power Boiler firing 100% No. 6 fuel oil (2004-2005 data) [b]	3,316.4	459.6	48.9	193.6	166.5	2.7	---	145.9	0.015	0.0011	0.365
No. 4 Combination Boiler	820.4	413.2	780.3	99.2	71.9	22.4	--	36.1	0.065	0.0047	0.084
No. 4 Lime Kiln	0.04	101.4	6.8	51.3	50.4	2.5	2.6	0.0018	0.16	--	--
Bark Handling System	--	--	--	14.6	10.6	175.4	--	--	--	--	--
No. 4 Recovery Boiler	14.7	473.2	1,249.3	134.7	101.0	9.5	11.3	1.50	0.012	6.8E-05	--
No. 4 Smelt Dissolving Tank [d]	27.7	57.1	9.4	34.9	31.4	94.4	5.1	--	0.010	6.8E-05	--
Black Liquor/Green Liquor Tanks [d]	--	--	--	--	--	9.7	3.0	--	--	--	--
Caustic Area [d]	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Total- Past Actual	**4,179.2**	**1,504.5**	**2,094.7**	**530.0**	**433.5**	**329.2**	**26.0**	**183.5**	**0.26**	**0.0059**	**0.449**
Increase Due to Project	**-3,899.6**	**397.2**	**1,705.3**	**111.7**	**87.7**	**482.0**	**57.7**	**-163.6**	**0.11**	**0.0019**	**-0.449**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0.6	0.1	3.0
Netting Triggered?	No	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	No	No	No	No
CONTEMPORANEOUS EMISSION CHANGES											
MACT I Compliance Project (9/00) (Permit nos. 1070005-007-AC and -017-AC) - startup 2002											
--Increase Due to New Thermal Oxidizer	109.7	151.4	8.8	30.7	30.7	9.1	0.89	7.7	--	--	--
--Increase Due to Modified No. 4 Comb. Boiler	548.7	37.8	--	--	--	--	0.47	21.9	--	--	--
--Increase Due to BSW System w/Condensate Treatment	--	--	--	--	--	48.6	58.7	--	--	--	--
--Decrease Due to Existing Thermal Oxidizer	-749.8	-49.5	-0.3	-20.6	-20.6	-3.2	-0.3	-26.9	--	--	--
--Decrease Due to Existing BSW System w/o Condensate Treatment	--	--	--	--	--	-52.1	-62.9	--	--	--	--
--Net Change	-91.4	139.7	8.5	10.1	10.1	2.4	-3.14 [c]	2.7	--	--	--
New Package Boiler (9/02) (Permit No. 1070005-018-AC) - startup Oct. 2002											
--Increase Due to New Package Boiler (EU 044)	0.1	39.4	16.5	1.5	1.5	1.1	--	--	[e]	[e]	[e]
--Decrease from old No. 6 Package Boiler	-0.07	-9.2	-2.1	-0.15	-0.15	--	--	--	[e]	[e]	[e]
--Net Change	0.03	30.20	14.40	1.35	1.35	1.1	--	--	[e]	[e]	[e]
Brown Stock Washer and Oxygen Delignification System (7/04) (Permit No. 1070005-024-AC) - startup Feb. 2006											
--Increase Due to No. 4 Comb. Boiler/No. 5 Power Boiler	236.3	--	0.3	--	--	4.0	17.1	9.5	--	--	--
--Increase Due to Pulp Storage Tanks	--	--	--	--	--	63.1	9.6	--	--	--	--
--Decrease from existing BSW System, BL Filter, etc.	--	--	--	--	--	-128.5	-77.1	--	--	--	--
--Net Change	236.3 [c]	--	0.3	--	--	-61.4	-50.4	9.5	--	--	--
No. 4 Power Boiler Shutdown (Sep. 2003)	-270.6	-33.6	-3.6	-18.1	-15.7	-0.2	--	-11.9	-0.005	-0.000081	-0.027
Total Contemporaneous Emission Changes	**-362.0**	**-3.4**	**19.6**	**-6.7**	**-4.3**	**-58.10**	**-53.5**	**0.3**	**-0.005**	**-0.000081**	**-0.027**
TOTAL NET CHANGE*	**-4,261.6**	**393.7**	**1,724.9**	**105.0**	**83.5**	**423.9**	**4.2**	**-163.3**	**0.11**	**0.0019**	**-0.475**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0.6	0.1	3.0
PSD REVIEW TRIGGERED?	No	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	No	No	No	No	No

Notes:

[a] Total future potential emissions from Table 2

[b] Total future potential emissions from Table 3

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

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

* Total Net Change: Credit for PM, NO_x, and SO_2 cannot all be taken in this table since much of the emission reductions for the No. 5 Power Boiler have been taken to obtain an exemption from the BART requirements