Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

March 30, 2006

CERTIFIED MAIL - Return Receipt Requested

Mr. Theodore D. Kennedy
Vice President – Palatka Operations
Georgia-Pacific Corporation
Palatka Mill
P.O. Box 919
Palatka, Florida 32178-0919

RE: Request to Modify the No. 4 Recovery Boiler
Project No.: 1070005-035-AC/PSD-FL-367

Dear Mr. Kennedy:

One copy of the Technical Evaluation and Preliminary Determination, the Public Notice, and the Draft air construction permit for Georgia-Pacific Corporation's Palatka Mill located North of CR 216 and West of US 17, Palatka, Putnam County, is enclosed. The permitting authority's "INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT" and the "PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT" must be published as soon as possible. Proof of publication, i.e., newspaper affidavit, must be provided to the permitting authority's office within 7 (seven) days of publication pursuant to Rule 62-110.106(5), F.A.C. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Please submit any written comments you wish to have considered concerning the permitting authority's proposed action to Jeffery F. Koerner, P.E., at the above letterhead address. If you have any other questions, please contact Bruce Mitchell at 850/413-9198.

Sincerely,

Trina L. Vielhauer
Chief
Bureau of Air Regulation

TLV/jfk/bm

Enclosures

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Theodore D. Kennedy
Vice President – Palatka Operations
Georgia Pacific
Palatka Mill
Post Office Box 919
Palatka, Florida 32178-0919

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X TJ Daniels ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) T. J. Daniels

C. Date of Delivery 4-3-06

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (*Extra Fee*) ☐ Yes

2. Article Number
(*Transfer from service label*) 7000 1670 0013 3110 0772

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 1670 0013 3110 0772

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

Postmark Here

Mr. Theodore D. Kennedy
Vice President – Palatka Operations
Georgia Pacific
Palatka Mill
Post Office Box 919
Palatka, Florida 32178-0919

PS Form 3800, May 2000 See Reverse for Instructions

In the Matter of an
Application for Permit by:

Georgia-Pacific Corporation P.O. Box 919 Palatka, Florida 32178-0919	Draft Air Construction Permit Project No.: 1070005-035-AC PSD Permit Project No.: PSD-FL-367 Palatka Mill Putnam County

______________________________/

WRITTEN NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT

Facility Location: The applicant, Georgia-Pacific Corporation, applied to the permitting authority for an air construction permit for a modification to the existing No. 4 Recovery Boiler (RB) at its Palatka Mill located North of CR 216 and West of US 17, Palatka, Putnam County.

Project: The applicant, Georgia-Pacific Corporation, applied on November 18, 2005, to the permitting authority for an air construction permit for a modification to the existing No. 4 RB.

The permit is being issued to authorize a modification to the existing No. 4 RB, which involves extensive replacement of several tubes (floor, generating bank, economizer and superheater), replacement or changes of the combustion air systems (including adding a fourth combustion air system), addition of a crystallizer and associated storage/flash tank, and miscellaneous changes (i.e., baffles, heat exchanger, piping, etc.) to two concentrators associated with the existing No. 4 multiple effect evaporator set.

The existing facility is located in an area designated as Attainment for all pollutants subject to state and federal Ambient Air Quality Standards pursuant to Rule 62-204.340, F.A.C. The existing plant is a major facility with respect to the Prevention of Significant Deterioration (PSD) of Air Quality as defined in Rules 62-210.200(Definitions) and 62-212.400(PSD), F.A.C. New projects must undergo an applicability analysis for PSD preconstruction review. Because of the close timing of the applications for modifications to the existing Nos. 4 RB, Lime Kiln (LK) and Combination Boiler (CB), the PSD netting analysis includes all of the contemporaneous emission changes at the facility over the last five years and the potential modifications to the Nos. 4 LK and CB, as well as the No. 4 RB.

The proposed draft permit includes the following preliminary BACT determinations for the modification to the No. 4 RB. PM/PM_{10} emissions will be minimized by the continued use of the existing electrostatic precipitator, with compliance demonstrated by annual stack testing. CO and VOC emissions will be minimized by proper furnace design and efficient combustion of the fuels; and, compliance will be demonstrated by the use of a continuous emissions monitoring system (CEMS) for CO and stack testing for VOC every five years for operation permit renewal. SO_2 and sulfuric acid mist (SAM) emissions will be minimized during startup by the firing of natural gas (pilot) and fuel oil (includes blended on-specification fuel oil), with a maximum sulfur content limit of 2.10%, by weight; and, during times of black liquor feed loss, fuel oil (includes blended on-specification fuel oil) will be fired as an alternate fuel; in addition, the No. 4 RB will be limited to a 12-month rolling SO_2 emissions cap of 153.9 tons, with compliance demonstrated by a CEMS, in order to escape PSD preconstruction new source review. NO_x emissions will be minimized by the installation/addition of a fourth level of combustion air and good combustion practices, with compliance demonstrated by a CEMS. The No. 4 Power Boiler will be permanently shutdown as part of this project.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the complete project file is also available at the Department's Northeast District Office, 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590 (Telephone: 904/807-3300).

Notice of Intent to Issue Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all applicable provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S., or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments and requests for public meetings regarding the draft permit should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed will be made available for public inspection. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen (14) days of publication of the attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when each petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this "Written Notice of Intent to Issue Air Permit" package (including the Public Notice, the Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail or sent electronically (with Received Receipt) before the close of business on 3/30/06 to the persons listed below.

Mr. Theodore D. Kennedy *, VP – Palatka Operations, Georgia-Pacific Corporation, Palatka Mill
Ms. Myra Carpenter, G-PC
Mr. Mark Aguilar, P.E., G-PC
Mr. Chris Kirts, NED Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency Clerk, receipt of which is hereby acknowledged.

Mary L. Harvey 3/30/06
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT

Permitting Authority
Department of Environmental Protection
Bureau of Air Regulation

Draft Air Construction Permit Project No.: 1070005-035-AC/PSD-FL-367

Georgia-Pacific Corporation
Palatka Mill
Putnam County

Applicant: The applicant for this project is the Georgia-Pacific Corporation, Palatka Mill. The applicant's Authorized Representative is: Mr. Theodore D. Kennedy, Vice President – Palatka Operations, Georgia-Pacific Corporation, Palatka Mill, P.O. Box 919, Palatka, Florida 32178-0919.

Facility Location: The applicant operates the Palatka Mill, which is a paper and pulp mill located North of CR 216 and West of US 17, Palatka, Putnam County.

Project: The applicant, Georgia-Pacific Corporation, applied on November 18, 2005, to the permitting authority for an air construction permit for a modification to the existing No. 4 Recovery Boiler (RB) at its Palatka Mill. The permit is being issued to authorize a modification to the existing RB, which involves extensive replacement of several tubes (floor, generating bank, economizer and superheater), replacement or changes of the combustion air systems (including adding a fourth combustion air system), addition of a crystallizer and associated storage/flash tank, and miscellaneous changes (i.e., baffles, heat exchanger, piping, etc.) to two concentrators associated with the existing No. 4 multiple effect evaporator set.

The existing facility is located in an area designated as Attainment for all pollutants subject to state and federal Ambient Air Quality Standards pursuant to Rule 62-204.340, F.A.C. The existing plant is a major facility with respect to the Prevention of Significant Deterioration (PSD) of Air Quality as defined in Rules 62-210.200(Definitions) and 62-212.400(PSD), F.A.C. New projects must undergo an applicability analysis for PSD preconstruction review. Because of the close timing of the applications for modifications to the existing Nos. 4 RB, Lime Kiln (LK) and Combination Boiler (CB), the PSD netting analysis includes all of the contemporaneous emission changes at the facility over the last five years and the potential modifications to the Nos. 4 LK and CB, as well as the No. 4 RB.

The total net potential annual emissions from the proposed project and pending projects (noted above) in terms of "tons per year" (TPY) will be: 1623 TPY of carbon monoxide (CO); 744 TPY of nitrogen oxides (NO_x); 333/274 TPY of particulate matter (PM/PM_{10}); 39.0 TPY of sulfur dioxide (SO_2); 26 TPY of sulfur acid mist (SAM); 389 TPY of volatile organic compounds (VOC); and, 9 TPY of total reduced sulfur compounds (TRS). The affected pollutants that exceed the PSD significant emission rates pursuant to Rule 62-210.200(Definitions), F.A.C., are: CO; NO_x; PM/PM_{10}; SAM; and, VOC. Therefore, the affected pollutants must undergo preconstruction evaluation pursuant to Rule 62-212.400(PSD), F.A.C., which requires a Best Available Control Technology (BACT) determination and an appropriate air quality modeling analysis.

The proposed draft permit includes the following preliminary BACT determinations for the modification to the No. 4 RB. PM/PM_{10} emissions will be minimized by the continued use of the existing electrostatic precipitator, with compliance demonstrated by annual stack testing. CO and VOC emissions will be minimized by proper furnace design and efficient combustion of the fuels; and, compliance will be demonstrated by the use of a continuous emissions monitoring system (CEMS) for CO and stack testing for VOC every five years for operation permit renewal. SO_2 and sulfuric acid mist (SAM) emissions will be minimized during startup by the firing of natural gas (pilot) and fuel oil (includes blended on-specification fuel oil), with a maximum sulfur content limit of 2.10%, by weight; and, during times of black liquor feed loss, fuel oil (includes blended on-specification fuel oil) will be fired as an alternate fuel; in addition, the No. 4 RB will be limited to a 12-month rolling SO_2 emissions cap of 153.9 tons, with compliance demonstrated by a CEMS, in order to escape PSD preconstruction new source review. NO_x emissions will be minimized by the installation/addition of a fourth level of combustion air and good combustion practices, with compliance demonstrated by a CEMS. The No. 4 Power Boiler will be permanently shutdown as part of this project.

An air quality impact analysis was conducted. The maximum predicted PSD Class II increments consumed by this project and all other sources in the area will be as follows:

Pollutant	PSD Class II Increment Consumed (ug/m3)	Allowable Increment (ug/m3)	Percent Increment Consumed
PM_{10}			
Annual	0	17	0
24-hour	6	30	20
NO_2			
Annual	7	25	28

The maximum predicted project impacts in the Class I Okefenokee National Wilderness Area are less than the applicable modeling significant impact levels. Therefore, a multi-source increment consumption modeling analysis was not required for this area. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

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Mediation: Mediation is not available in this proceeding.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

PROJECT

Draft Permit No. 1070005-035-AC (PSD-FL-367)
Georgia-Pacific Palatka Mill
Facility ID No. 1070005
Modification of No. 4 Recovery Boiler

COUNTY

Putnam County, Florida

APPLICANT

Georgia-Pacific Corporation
Palatka Mill
P.O. Box 919
Palatka, Florida 32178-0919

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation - Air Permitting North
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

March 30, 2006

1. APPLICATION INFORMATION

Facility and Location

The Georgia-Pacific Corporation operates an existing pulp and paper mill (SIC No. 2611, 2621) in Palatka located North of CR 216 and West of US 17, Putnam County, Florida. The UTM coordinates of this facility are: Zone 17; 434.0 km East; and, 3283.4 km North. The existing Palatka Mill is subject to the following regulatory categories:

Title III: The existing facility is a major source of hazardous air pollutants (HAP).

Title IV: The existing facility operates no units subject to the acid rain provisions of the Clean Air Act.

Title V: The existing facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The existing facility is a PSD-major facility pursuant to Rule 62-212.400, F.A.C.

Industrial Process Description

Initial construction of the existing No. 4 recovery boiler began in December of 1976. The boiler was manufactured by Combustion Engineering and is the heart of the Kraft recovery process, which fulfills the following essential functions:

- Evaporates residual moisture from the liquor solids;
- Burns the organic constituents (lignin derivatives, carbohydrates, soap and waxes);
- Supplies heat for steam generation;
- Reduces oxidized sulfur compounds to sulfide;
- Recovers inorganic chemicals (primarily sodium sulfate) in molten form; and
- Conditions the products of combustion to minimize chemical carryover.

The heavy black liquor from the concentrators is sprayed into the furnace through liquor guns assisted by steam atomizing nozzles. The liquor droplets burn in suspension, dry and then partially pyrolyze before falling onto the char bed at the bottom of the furnace. Incomplete combustion in the porous char bed causes carbon and carbon monoxide to act as reducing agents, thus converting sulfate and thiosulfate to sulfide. The heat is sufficient to melt the sodium salts, which filter through the char bed to the floor of the furnace. The smelt, mainly sodium sulfide and sodium carbonate, is gravity fed through water-cooled spouts to one of two smelt dissolving tanks.

Air is introduced into the furnace through three sets of ports designated from bottom to top as primary, secondary and tertiary air. The primary air ports are located a few feet above the hearth and extend around the four walls of the furnace to provide as low a velocity as practical, while supplying 50% to 60% of the combustion air required. Secondary and tertiary air is usually introduced at higher velocity to ensure uniform mixing and complete combustion of the unburned gases.

The furnace ahead of the main heat-absorbing sections can be considered as consisting of three distinct zones: a drying zone where the liquor is fired; a reduction zone at the bottom (char bed); and an oxidation zone in the turbulent upper section. Air is supplied to the furnace by forced-draft fans. The flue gases are drawn through the unit by large induced-draft fans at the exhaust of the electrostatic precipitator (ESP). For safety purposes, the furnace is kept under negative pressure, where some air is infiltrated through the nozzle openings and smelt spout openings. ["*Handbook for Pulp and Paper Technologists*", Gary A. Smook, Third Edition, page 142 - 145.]

Project Description

The applicant requests an air construction permit to perform the following modifications to the existing pulp and paper mill.

1. The applicant plans to replace a large percentage of the tubes in the No. 4 Recovery Boiler (EU-018), including tubes in the superheater, economizer, main generating banks and floor. The tube replacements are not considered to be routine because the original tubes have been in place since the unit was originally constructed in the mid 1970's. In addition, physical changes will be made to the combustion air system in order to lower the peak furnace exhaust gas temperature and velocity into the superheater. This effort is intended to reduce the potential for corrosion and pluggage of the superheater. The new air system is also expected to reduce particulate matter carry over and fouling in the boiler convection tube banks. By staging the combustion air, the applicant anticipates an increase in boiler efficiency, which may reduce some pollutants due to better combustion (i.e., total reduced sulfur compounds and carbon monoxide), but may result in slight increases in nitrogen oxides. To offset the potential emissions increase in nitrogen oxides, the applicant proposes to install a fourth level of combustion air (quaternary air) to provide additional staged combustion. The capacity of the No. 4 recovery boiler will remain unchanged at 789,000 lbs/hr steam (24-hour average) based on

steam conditions of 850° F – 900° F at 1250 psi and 210,000 lb/hour of black liquor solids (BLS).

2. The applicant proposes to modify the black liquor evaporator system, specifically the No. 4 multiple effect evaporator (MEE) set. The change will increase the concentration of the black liquor solids (BLS) from 65% to 75%, which will be fired in the recovery boiler. The purpose is to increase the efficiency of the recovery boiler by reducing the amount of water in the black liquor solids (BLS) being fired. A crystallizer vessel will be installed to remove additional moisture from black liquor leaving the concentrators. The crystallizer will increase the temperature of the black liquor, which will discharge into a storage/flash tank at a lower pressure to "flash-off" vapors (water moisture). Vapors will be routed to the existing evaporator system and collected as part of the existing non-condensable gas (NCG) collection system. The applicant expects to fire less supplemental fuel oil as a result of improved firing of BLS. The applicant anticipates that the increased recovery boiler efficiency will reduce the amount of steam produced from other existing boilers, which fire fuel oil. However, the improved firing rate may also result in more exhaust gas flow and increased particulate matter emissions.
3. The applicant plans to remove some internal baffles and resize some downcomer piping in the existing concentrators due to scaling problems that lead to frequent "boil outs". The proposed changes will improve liquor circulation and increase velocity through the tubes, which should reduce scaling and fouling as well as the number of "boil outs". An external heat exchanger will be added to the existing concentrators to preheat the black liquor with steam prior to entering the concentrators, which will improve evaporation. The changes allow the fuel feed system to more closely match the existing capacity of the recovery boiler. Emissions generated from the external heat exchanger operation will be controlled by the existing NCG collection system.
4. Also as a part of this project, the applicant proposes to reduce the No. 6 fuel oil sulfur content from 2.35% to 2.10% sulfur by weight. This change affects the recovery boiler, the lime kiln, and the combination boiler. In addition, the applicant requests a limitation on the maximum amount of No. 6 fuel oil that can be fired in a 12-month period by the combination boiler. These changes allow the project to avoid PSD preconstruction review for sulfur dioxide (SO_2).

The total cost of the project is estimated to be approximately $32 million. The preliminary schedule is:

- May 2006: Modify combustion air system; replace 25% of wall tubes in recovery boiler; and start construction of new crystallizer and upgrades to concentrator/evaporator;
- April/May of 2007: Replace tubes in superheater, economizer, and 25% of wall in recovery boiler; and
- May 2008: Startup of new crystallizer/evaporator.

Reviewing and Processing Schedule

- November 18, 2005: Receipt of application;
- December 16, 2005: Request for additional information;
- January 13, 2006: Receipt of additional information;
- February 9, 2006: Request for additional information;
- February 20, 2006: Receipt of additional information; application deemed complete.

2. RULE APPLICABILITY

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the rules and regulations defined in the following generally applicable Chapters of the Florida Administrative Code: 62-4 (Permitting Requirements); 62-204 (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference); 62-210 (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms); 62-212 (Preconstruction Review, PSD Review and BACT, and Non-attainment Area Review and LAER); 62-213 (Title V Air Operation Permits for Major Sources of Air Pollution); 62-296 (Emission Limiting Standards); and 62-297 (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures). Specifically, the recovery boiler is subject to Rule 62-296.404 (Kraft Pulp Mills and Tall Oil Plants), F.A.C.

Federal Regulations

The Environmental Protection Agency establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 identifies New Source Performance Standards (NSPS) for a variety of industrial activities. Part 61 specifies the National Emissions Standards for Hazardous Air Pollutant (NESHAP) based on specific pollutants. Part 63 identifies National Emissions Standards for Hazardous Air Pollutant (NESHAP) based on the Maximum Achievable Control Technology (MACT) for given source categories. Specifically the recovery boiler is subject to the following applicable provisions: NSPS Subpart BB in 40 CFR 60 (Kraft Pulp Mills); and NESHAP Subpart MM MACT II requirements in 40 CFR 63 (Recovery Combustion Sources at Pulp Mills).

General PSD Applicability

The Department regulates major air pollution facilities in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as approved by the EPA in Florida's State Implementation Plan and defined in Rule 62-212.400, F.A.C. A PSD review is required in areas currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or areas designated as "unclassifiable" for a given pollutant. A facility is considered "major" with respect to PSD if it emits or has the potential to emit: 250 tons per year or more of any regulated air pollutant, or 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 PSD Major Facility Categories, or 5 tons per year of lead.

New projects at existing PSD-major sources are reviewed for PSD applicability based on net emissions increases. Each regulated pollutant is evaluated for PSD applicability based on emissions thresholds known as the Significant Emission Rates defined in Rule 62-210.200 (Definitions), F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant and evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "PSD-significant" pollutants. As part of PSD preconstruction review, applicants must also provide an air quality analysis demonstrating that the project will not result in adverse ambient impacts.

PSD Applicability for the Project

The project is located in Putnam County, which is in an area that is currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or otherwise designated as unclassifiable. Actual annual emissions of one or more pollutants from the facility are greater than the facility applicability thresholds defined above. The plant is an existing PSD-major facility as defined in Rule 62-212.400, F.A.C. Therefore, the project must be reviewed for PSD applicability.

The requested potential annual emissions from only the recovery boiler will be: 331 tons/year of particulate matter (PM/PM_{10}); 738 tons/year of nitrogen oxides (NO_x); 2246 tons/year of carbon monoxide (CO); 15.9 tons/year of sulfuric acid mist (SAM); 155 tons/year of sulfur dioxide (SO_2); 34 tons/year of total reduced sulfur (TRS); and 138 tons/year of volatile organic compounds (VOC). However, this plant has multiple major projects proposed, or about to be proposed, including modifications to the No. 4 Recovery Boiler, the No. 4 Lime Kiln, and the No. 4 Combination Boiler. In addition, several previous projects have recently been permitted at this plant. Due to the close timing of these projects, the Department requested that the PSD netting analysis include all contemporaneous emission increases and decreases associated with past permitting projects within the last five years as well as the planned (pending) modifications to the No. 4 Lime Kiln and the No. 4 Combination Boiler. In this manner, the full emissions increases could be accounted for in the ambient air quality analysis and individual projects could not inadvertently escape determinations of Best Available Control Technology (BACT). The following table summarizes the PSD netting analysis for this project.

Table 1. PSD Netting Analysis

Pollutant	Emissions in Tons per Year					Subject to PSD?
	Past Actual Emissions	Potential Emissions	Contemporaneous Emission Changes [3]	Net Emissions Increase	PSD Significant Emission Rates	
PM	343.2	683.4	-6.7	333	25	Yes
PM_{10}	270.7	549.4	-4.3	274	15	Yes
SO_2	839.9	1207.2 [1]	-362.0	39	40	No
NO_x	1,032.0	1779.8	-3.4	744	40	Yes
CO	1,938.0	3,541.1	19.6	1,623	100	Yes
SAM	37.1	62.3	0.3	26	7	Yes
VOC	326.3	837.5	-122.02	389	40	Yes

Pollutant	Emissions in Tons per Year					Subject to PSD?
	Past Actual Emissions	Potential Emissions	Contemporaneous Emission Changes [3]	Net Emissions Increase	PSD Significant Emission Rates	
TRS	21.1	75.27 [2]	-45.3	9	10	No
PB	0.25	0.4	-0.005	0.12	0.6	No
Hg	0.00506	0.00724	-0.000081	0.0021	0.1	No
Fl	0.08	0.09	-0.027	-0.014	3.0	No

Note: Based on information received: April 15, May 6, June 14 and November 18, 2005 (recovery boiler application); and February 20, 2006 (additional information provided).

[1] This value is a 12-month rolling emissions cap for SO_2 emissions from the recovery boiler (153.9 TPY), lime kiln (151.1 TPY) and combination boiler (902.2 TPY). The cap includes the following:

a. A fuel oil sulfur content limitation of 2.10% by weight for the recovery boiler, lime kiln and combination boiler.

b. A fuel oil consumption limitation of 5.03 million gallons during any consecutive 12-months for the combination boiler.

c. An annual SO_2 limit of 12 ppmvd @ 8% O_2 for the recovery boiler based on a maximum flow rate of 294,000 dscfm @ 8% O_2.

d. Based on a petcoke sulfur content limitation of 7.0% by weight for the lime kiln, 80% "natural" scrubbing from the lime mud, and 90% reduction from the wet scrubber.

e. Compliance will be demonstrated by an SO_2 CEMS for the recovery boiler.

[2] For TRS, this value includes the following:

a. An annual TRS limit of 13 ppmvd @ 10% O_2 for the lime kiln (16.3 TPY, based on a maximum flow rate of 54,200 dscfm @ 10% O_2).

b. An annual TRS limit of 5 ppmvd @ 8% O_2 for the recovery boiler (34.2 TPY, based on a maximum flow rate of 294,000 dscfm @ 8% O_2).

[3] In addition to the projects described above, contemporaneous emissions changes included such projects as: new bleach plant; chlorine dioxide plant; MACT I compliance project; new package boiler; brown stock washer system; shutdown of No. 4 Power Boiler.

The following pollutants exceed the PSD significant emissions rates specified in Rule 62-210.200(Definitions), F.A.C. and are subject to PSD preconstruction review: particulate matter (PM/PM_{10}); nitrogen oxides (NO_x); carbon monoxide (CO); sulfuric acid mist (SAM); and volatile organic compounds (VOC). These pollutants are subject to the PSD air quality analysis requirements and require determinations of Best Available Control Technology (BACT).

For SO_2 emissions, the applicant requested certain restrictions (recovery boiler, lime kiln, and combination boiler) limiting the net emissions increase to 39 TPY, which is less than significant and allowed the modification to avoid PSD preconstruction review. These restrictions will be established in the draft permit pursuant to Rule 62-212.400(12)(Source Obligation), F.A.C.

3. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) DETERMINATION

Description of BACT Determination Procedure

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) of Air Quality program, as defined in Rule 62-212.400, F.A.C. A PSD preconstruction review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (NAAQS) for a given pollutant or areas designated as "unclassifiable" such pollutants. A PSD-major facility is one that emits or has the potential to emit: 250 tons per year or more of any regulated air pollutant; or 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories; or 5 tons per year of lead.

For new PSD-major facilities and modifications to existing PSD-major facilities, each regulated pollutant is reviewed for

PSD applicability based on emissions thresholds known as the Significant Emission Rates identified in Rule 62-210.200(243), F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant and evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it is required to install BACT controls for each "PSD-significant" pollutant. In accordance with Rule 62-212.400(4), F.A.C., the applicant must provide the following information:

(a) A description of the nature, location, design capacity, and typical operating schedule of the source or modification, including specifications and drawings showing its design and plant layout;

(b) A detailed schedule for construction of the source or modification;

(c) A detailed description as to what system of continuous emission reduction is planned for the source or modification, emission estimates, and any other information necessary to determine best available control technology (BACT) including a proposed BACT;

(d) The air quality impact of the source or modification, including meteorological and topographical data necessary to estimate such impact and an analysis of "good engineering practice" stack height; and

(e) The air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the source or modification would affect.

"Best Available Control Technology" or "BACT" as is defined in Rule 62-210.200(38), F.A.C. as follows:

(a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted, which the Department, on a case by case basis, taking into account:

1. Energy, environmental and economic impacts, and other costs;

2. All scientific, engineering, and technical material and other information available to the Department; and

3. The emission limiting standards or BACT determinations of Florida and any other state;

determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

(b) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.

(c) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

(d) In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

The Department conducts case-by-case BACT determinations in accordance with the requirements given above. Additionally, the Department generally conducts such reviews so that the determinations are consistent with those conducted using the "Top-Down Methodology" described by EPA.

BACT Review for PM/PM_{10}

Discussion of PM/PM_{10} Emissions and Control Options

High temperatures in the char bed zone result in a partial vaporization of sodium and sulfur from the smelt. The fume is removed from the furnace with the combustion gases and condenses to a fine particulate consisting of sodium sulfate (Na_2SO_4) and sodium carbonate (Na_2CO_3). The loss of sodium (Na^+ and Na_2) increases sharply above 1341° F. It is important that the solids entrained with the combustion gases are cooled below their fusion temperature prior to contact with the superheater tubes; otherwise, ash and fume will adhere strongly to the tubes and form an insulating layer. The "sticky ash point" for the principal sodium salts (carbonate and sulfate) is about 1472° F. The typical recovery boiler is relatively tall to allow sufficient cooling of gas and entrained solids by the water wall tubes. The tubes in the boiler section become coated with particulate (ash) and reduce heat exchange efficiency; therefore, steam soot blowers are used to remove the ash coating, which is conditioned and removed by an electrostatic precipitator (ESP). ["*Handbook for Pulp and Paper Technologists*", Gary A. Smook, Third Edition, page 142 - 145.]

Available particulate matter control equipment for recovery boilers includes the following options:

Baghouse: A baghouse control system typically consists of a series of hanging, fine mesh bags designed to capture and remove particulate matter. Typically, the bags are periodically cleaned by pulsed jets of air or shaking. Baghouses are capable of control efficiencies exceeding 99%. However, recovery boiler exhaust gas has a relatively high moisture content (25% to 30%), which may cause bag filters to be "blinded" and plug requiring more frequent cleaning, maintenance, and replacement. For these reasons, a baghouse is generally not the control system of choice for removing particulate matter from a recovery boiler.

Electrostatic Precipitator (ESP): An ESP uses electrical power to charge particles which are then collected on large hanging plates. The plates are periodically rapped to discharge collected fly ash into ash hoppers. ESPs are capable of control efficiencies exceeding 99%. As reflected in EPA's RACT/BACT/LAER Clearinghouse, nearly all recovery boilers at pulp and paper mills in the United States use ESPs to control particulate matter emissions.

Wet Scrubber: High-energy wet scrubbers are also effective in removing particulate matter with control efficiencies approaching 98%. As reflected by a review of EPA's RACT/BACT/LAER Clearinghouse, wet scrubbers have been used by one mill for two existing recovery boilers (Georgia-Pacific Mill in Camas, Washington). However, in each case, the wet scrubber followed an ESP. The plant indicates that the wet scrubbers were installed to recover heat and make hot process water for use in the facility. The emissions limit for these units is 0.033 grains/dscf @ 8% O_2.

<u>Applicant's PM/PM_{10} BACT Review</u>

The applicant selects an ESP as the top control option. The existing No. 4 Recovery Boiler is already controlled by an ESP and no additional controls are proposed. A review of EPA's RACT/BACT/LAER Clearinghouse shows that previous particulate matter BACT emission limits range from 0.021 to 0.15 grains/dscf. Based on the existing ESP, the applicant proposes to meet an emissions standard of 0.030 grains/dscf @ 8% O_2, which is the current emissions standard for the recovery boiler as established in Permit No. PSD-FL-226 issued on September 21, 1995. This limit is at the low end of the range for previous BACT determinations. For comparison, NSPS Subpart BB in 40 CFR 60 specifies a particulate matter emissions standard of 0.044 grains/dscf @ 8% O_2 for recovery boilers and NESHAP Subpart MM in 40 CFR 63 specifies a particulate matter emissions standard of 0.044 grains/dscf @ 8% O_2 for existing recovery boilers as a surrogate for reducing HAP metal emissions. The applicant requests a visible emissions limit of 20% opacity (normal operation) with no more than 6% of opacity readings collected during a calendar quarter of no more than 35%.

<u>Department's PM/PM_{10} BACT Review</u>

The Department agrees that an ESP is the top control system for the recovery boiler project. Compliance tests conducted in 2000 and 2004 on the existing recovery boiler resulted in a mean emissions rate of 0.0262 gr/dscf @ 8% O_2 and 0.0220 gr/dscf @ 8% O_2, respectively. Therefore, it is reasonable to expect that the ESP system can continue to achieve this level of emissions or better. In addition and for a similar process and control, the existing recovery boiler has been able to easily comply with the latest federal NESHAP Subpart MM MACT II regulations of 0.044 grains/dscf @ 8% O_2 (40 CFR 63.862(a)(1)), which is less stringent than the current limit for the recovery boiler.

Therefore, the Department's draft particulate matter BACT determination is 0.030 grains/dscf @ 8% O_2 based on the existing ESP control system. The equivalent mass emissions rates are 75.6 lbs/hr and 331.1 tons/year. Compliance shall be demonstrated by conducting initial and annual stack tests in accordance with the requirements contained in 40 CFR 63.865. Permit No. AC54-192550 (PSD-FL-171) issued on June 12, 1991 established a BACT determination for visible emissions of no more than 20% opacity for the existing recovery boiler. The Department's draft PM BACT determination is to retain this visible emissions limit. For purposes of comparison, the following table summarizes current PM emissions standards for recovery boilers operating in Florida.

Facility/Unit	Emissions Standards
Particulate Matter (PM/PM_{10})	
International Paper, #1 RB	0.042 grains/dscf @ 8% O_2; ESP; NESHAP Subpart MM alternate "average" for boilers; stack test
International Paper, #2 RB	0.042 grains/dscf @ 8% O_2; ESP; NESHAP Subpart MM

Facility/Unit	Emissions Standards
Particulate Matter (PM/PM_{10})	
	alternate "average" for boilers; stack test
Smurfit-Stone - Panama City, # 1 RB	0.044 grains/dscf @ 8% O_2; ESP; NESHAP Subpart MM; stack test
Smurfit-Stone - Panama City, # 2 RB	0.044 grains/dscf @ 8% O_2; ESP; NESHAP Subpart MM; stack test
Smurfit-Stone - Fernandina Beach , # 4 RB	0.044 grains/dscf @ 8% O_2; ESP; NESHAP Subpart MM; stack test
Smurfit-Stone - Fernandina Beach , # 5 RB	0.044 grains/dscf @ 8% O_2; ESP; NESHAP Subpart MM; stack test
Buckeye, #2 RB	0.044 grains/dscf @ 8% O_2; ESP; NESHAP Subpart MM; stack test
Buckeye, #3 RB	0.044 grains/dscf @ 8% O_2; ESP; NESHAP Subpart MM; stack test

BACT Review for NOx Emissions

Discussion of NOx Emissions and Control Options

Thermal NOx emissions form from a series of chemical reactions in which diatomic nitrogen (N_2) and oxygen (O_2) present in the combustion air dissociate in a high temperature combustion zone and react to form NOx. Thermal NOx emissions from recovery boiler are not believed to be a significant portion of the overall NOx emissions due to relatively low combustion zone temperatures. The oxidation of nitrogen in the black liquor solids (fuel NOx) is the primary mechanism of forming NOx emissions in recovery boilers. However, increased combustion zone temperatures have shown to increase the amount of fuel nitrogen that is oxidized resulting in increased fuel NOx emissions. Overall NOx emissions are relatively low for recovery boilers because black liquor solids typically contain low amounts of nitrogen (0.10% by weight).

The two main approaches for reducing NO_x emissions from boilers are post-combustion controls and combustion modifications. Post-combustion controls include:

1. *Selective Catalytic Reduction (SCR)*: SCR systems work by injecting aqueous or anhydrous ammonia into the exhaust gas stream and passing the exhaust across a catalyst bed to further the chemical NOx reduction reaction. This system also converts NO_x to elemental nitrogen, carbon dioxide, and water vapor. The optimum temperature range for an SCR catalyst to work efficiently is 550° to 1000° F (best temperature window is between 700° F to 750° F). To achieve the optimum temperature window, most SCR designs install the reaction chamber downstream of the economizer, but upstream of the air pre-heater, where the metal oxide-based catalyst works best. Reheating of the flue gas would be required for reaction chambers located downstream of the air pre-heater. SCR system can achieve NOx control reductions of 90% on some applications.

   Catalysts lose their effectiveness for a number of reasons, including poisoning, thermal sintering, binding, plugging, fouling, erosion and aging. Certain contaminants present in the exhaust flue gas can poison and deactivate the catalyst by diffusing into the catalyst's active pore sites and occupying them irreversibly. Such contaminants include calcium and magnesium oxides, potassium, sodium, arsenic, fluorine and lead. High flue gas temperatures can cause thermal sintering, which is a permanent loss of catalyst activity due to a change in the pore structure of the catalyst. Thermal sintering is dependent upon the catalyst composition and structure, but has occurred at temperature as low as 450° F. Ammonia salts, fly ash, and other PM in the flue gas stream can cause binding, plugging, and/or fouling of the catalyst through deposits left in the active pore sites of the catalyst. This reduces the number of sites available for reducing NO_x emissions and increases the flue gas pressure loss across the catalyst bed. Exhausts heavily laden with particulate matter can cause excessive erosion of the catalyst. Erosion can be reduced by hardening the leading edges of the catalyst; however, this reduces the number of active pore sites. As the catalyst ages, its physical and chemical properties change making it less effective.

   Keeping the catalyst active can be accomplished in several ways, including soot blowing, removing as much of the flue gas contaminants prior to reaching the catalyst, and replacing the catalyst on a routine basis prior to becoming ineffective. Catalyst replacement is a significant portion of the costs for operating an SCR system. Similar to a SNCR system, a SCR system requires an aqueous or anhydrous ammonia or urea storage, feed, and control system, to operate properly.

2. *Selective Non-Catalytic Reduction (SNCR)*: SNCR systems work by injecting ammonia or urea into the combustion chamber of the furnace to convert NO_x to elemental nitrogen (N_2), carbon dioxide (CO_2), and water. The optimum

temperature range for an ammonia-based system is approximately 1600° F to 2000° F and for a urea-based system is 1650° F to 2100° F. The reaction must take place within the specified temperature range or it is possible to generate NO_x instead of reducing it. Increasing the residence time available for mass transfer and chemical reactions generally improves NO_x reduction. Variations in boiler steam load or flue gas temperature make the design and operation of a SNCR system more difficult. SNCR systems can achieve NOx reductions of 50% on some applications.

Combustion modifications include:

1. *Over-Fire Air (OFA)*: The recovery boiler currently stages combustion air with a 3-level overfire air system to reduce NO_x emissions. Initial combustion air is provided with the fuel in a ratio to produce a reducing flame. Subsequent combustion air is staged to complete combustion of the fuel while maintaining low temperatures to prevent thermal NOx formation. A variable exhaust flow can make application of OFA difficult. OFA systems can reduce NOx emissions by 20% to 50%.
2. *Low NOx Burners (LNBs)*: A LNB provides a stable flame that has several different zones. For example, the first zone can be primary combustion. The second zone can be fuel reburning with fuel added to chemically reduce NO_x. The third zone can be final combustion in low excess air to limit the temperature. LNBs represent a method for lowering NO_x emissions for the combustion of fossil fuels in a recovery boiler; however, the existing unit only burns No. 6 fuel oil for periods of startup and shutdown and not during normal operation. Natural gas is only burned to fuel a pilot light, which in turn is used to light the fuel oil. Therefore, LNBs would have little impact on the overall NOx emissions from the recovery boiler. NOx reduction potential varies from 20% to 50%.
3. *Flue Gas Recirculation (FGR)*: Recirculation of cooled flue gas reduces combustion temperature by diluting the oxygen content of the combustion air and by causing heat to be diluted by the incoming cooler air. Heat in the flue gas can be recovered by a heat exchanger. This reduction of temperature lowers the thermal NO_x concentration that is generated. High particulate matter loading in the flue gas creates technical problems which presents difficulties in implementing FGR in a recovery boiler. NOx reduction potential varies from 15% to 20%.
4. *Low Excess Air (LEA)*: Excess airflow combustion has been correlated to the amount of thermal NO_x generated. Limiting the net excess airflow can limit the thermal NO_x content of the flue gas. NOx reduction potential can vary from 0 to 30%. Most recovery boilers operate with low excess air (typical oxygen levels of 1% to 4%).

Each of the combustion modification techniques listed above involve lowering the temperature in the combustion chamber, which reduces the amount of thermal NO_x generated. Such combustion modifications require additional equipment, such as new fans or burners, as well as controls, to operate properly.

Applicant's NOx BACT Review

An SCR system is the top control option for reducing NOx emissions. However, the applicant expresses concerns regarding the feasibility of installing an SCR system due to premature deactivation of the catalyst. The recovery boiler fires black liquor solids (BLS) as the primary fuel, which results in high particulate matter loading of boiler exhaust. If the catalyst were installed prior to the ESP, the catalyst would be quickly plugged and fouled due to deposits from particulate matter in the flue gas. The applicant does not believe installation of an SCR system prior to the ESP is technically feasible. If the catalyst were installed after exiting the ESP control system, the flue gas stream would have to be heated from 425° F to approximately 700° F to achieve an effective operating temperature. The cost of firing a duct burner with natural gas would significantly add to the cost of operating an SCR system. In addition, fuel analyses of the BLS indicate the presence of sodium (18.7% by weight), potassium (1.09% by weight), and chlorine (0.56% by weight), which are known catalyst poisons. Again, the applicant expresses concerns regarding the technical feasibility of an SCR system due to premature deactivation of the catalyst from poisoning. The applicant estimates a total direct capital investment cost for a SCR system for the existing recovery boiler of nearly $16 million and total annualized costs (including annual operating costs) of nearly $7.5 million. Based on the actual NOx emissions (2003 – 2004) of 425 tons/year and assuming a 90% reduction (425 x 0.90 = 383 tons of NOx reduced), the cost effectiveness of an SCR system is estimated at nearly $20,000 per ton of NOx removed. The applicant rejects SCR as technically infeasible and cost prohibitive.

SNCR is the next top control option for reducing NOx emissions. The applicant believes that an SNCR system is not technically feasible for a recovery boiler, which is a complete chemical reaction system. Any disruption of the delicate balance of chemistry within the boiler could potentially damage it, impact the quality of the product, or unacceptably affect the system. The applicant contacted two SNCR vendors (Fuel-Tech, Inc. and Aker Kvaerner Power, Inc.). These companies indicated that SNCR systems are not yet commercially available for recovery boilers. Both companies are working on studies in Sweden to determine whether or not SNCR can be a viable NOx control option for recovery boilers. Based on these discussions, the applicant rejects SNCR because it is not commercially available for recovery boilers.

Of the available combustion modification techniques, staged combustion with overfire air (OFA) is the next likely control option. The existing recovery boiler currently employs staged combustion with primary, secondary and tertiary overfire air (OFA). The applicant proposes to add a 4^{th} level of OFA to further stage combustion air and inhibit NOx formation. A well-designed OFA and control system enhances the mixing of fuel with combustion air to promote uniform combustion, which removes hot and cold spots in the combustion zone. OFA systems are routinely employed to reduce NOx emissions from recovery boilers.

Typical NO_x emissions from recovery boilers range from 75 to 150 ppmv, depending upon the number of levels of combustion air used to control NO_x emissions. A review of EPA's RACT/BACT/LAER Clearinghouse shows previous NOx BACT determinations for recovery boilers ranging from 70 to 210 ppmv. The BACT control technologies include combustion control, staged combustion, boiler design and operation, and process controls. One entry lists LNBs, but the application is for a supplemental natural gas burner. Another entry lists the addition of a fourth level of combustion air with a NO_x emission limit of 100 ppmv. The current NO_x limit for the recovery boiler is 80 ppmvd @ 8% O_2 and 168.5 lbs/hour. The vendor for the OFA system guarantees NOx emissions in the range of 78 to 90 ppmvd @ 8% O_2 for a fourth level of combustion air ranges. This is based on a 75% solids content of black liquor solids (BLS), which is the proposed level after the new crystallizer is added. The current limit is at the low end of the vendor guarantees as well as previous NOx BACT determinations for recovery boilers. Considering a concurrent reduction in CO emissions, the applicant proposes to retain the current NO_x limit of 80 ppmvd @ 8% O_2 for the recovery boiler based on a 4^{th} level of OFA.

Department's NOx BACT Review

The Department does not endorse the applicant's SCR cost estimates, but does recognize the considerable costs of installing and operating such a system. It is noted that the applicant's cost effectiveness estimate of \$20,000 per ton of NOx removed was based on *actual* NOx emissions and not *potential* NOx emissions. Assuming the applicant's estimated annualized cost of \$7.5 million, potential NO_x emissions of 545 tons/year (based on 80 ppmvd), and a 90% reduction (545 x 0.90 = 490 tons of NOx reduced), the cost effectiveness of an SCR system would be closer to \$16,000 per ton of NOx removed.

A review of EPA's RACT/BACT/LAER Clearinghouse shows that previous NOx BACT determinations have relied upon combustion control techniques. The Department was unable to find any applications of an SNCR system on a recovery boiler. Based on the applicant's discussions with SNCR vendors, it does not appear that SNCR is commercially available for recovery boilers at this time. The BACT determination will be based on adding a 4^{th} level of combustion air.

In September of 1995, the Department issued as PSD permit (AC54-266676/PSD-FL-226) for this unit with a NOx BACT standard of standard 80 ppmvd @ 8% O_2. For reference, this is approximately 0.13 lb/MMBtu of heat input. A review of EPA's RACT/BACT/LAER Clearinghouse indicates that NO_x BACT standards range from 70 to 210 ppmvd @ 8% O_2. For the existing recovery boiler, actual test results show NO_x emissions vary from 45 to 65 ppmvd @ 8% O_2. The Department's draft NOx BACT determination is:

> As determined by data collected from the required continuous emissions monitoring system (CEMS), NOx emissions from the recovery boiler shall not exceed 80 ppmvd @ 8% O_2 based on a 30-day rolling average excluding authorized periods of startup, shutdown, and equipment malfunctions.

The new CEMS-based standard will demonstrate continuous compliance and ensure the use of good combustion practices. The new standard will replace the previous NOx standard and is believed to be more stringent due to the continuous compliance demonstration.

BACT Review for Emissions of Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

Discussion of CO/VOC Emissions and Control Options

CO and VOC emissions are formed due to incomplete combustion of the fuels. For many industrial boilers, CO emissions can be inversely proportional to the NO_x emissions. The two main options for reducing CO/VOC emissions are combustion modification and post-combustion controls.

Post-Combustion Controls: CO/VOC emissions can be oxidized to CO_2 either thermally or catalytically. Thermal oxidizers would rarely be used to control boiler exhausts because it requires much more fuel combustion to achieve the necessary oxidizing temperatures. For relatively dust-free exhausts, oxidation catalysts may be used to reduce CO/VOC emissions.

Depending on the specific pollutants, inlet concentrations and other factors, reductions approaching 90% are possible. Oxidation catalysts operate at temperatures between approximately 600° F and 1100° F.

Combustion Modification Techniques: Minimizing the formation of CO/VOC emissions from boilers is generally achieved by ensuring efficient combustion. Uniform and efficient combustion is a function of the three "T's": turbulence (thorough mixing of air and fuel), temperature (high enough to complete oxidation), and time (sufficient residence time at given combustion temperature). For the recovery boiler, good combustion includes adequate control of the ratio of black liquor solids (BLS) to combustion air in the combustion chamber of the boiler. In addition, staged combustion with overfire air promotes uniform mixing and complete combustion of the fuel.

Applicant's CO/VOC BACT Reviews

Oxidation catalysts are sensitive to poisoning, blinding, plugging, fouling, and erosion. If installed before the ESP, particulate matter would soon erode, plug and foul the catalyst. If installed after the ESP, the residual particulate matter would still be sufficient to build-up and clog catalyst pore spaces and reduce its effectiveness. In addition, black liquor solids (BLS) contain significant amounts of sodium (18.7% by weight), potassium (1.09% by weight), chlorine (0.56% by weight) as well as lesser amounts of zinc, lead, copper, magnesium, arsenic, and vanadium. These contaminants are recognized catalyst poisons that would prematurely deactivate the catalyst and disrupt operation. A review of EPA's RACT/BACT/LAER Clearinghouse identifies the following CO/VOC control options: boiler design, good combustion practices, proper combustion techniques and operating practices, combustion control, good combustion control of flame temperature and excess air, boiler design and operation, and efficient operation. These are all descriptions of "efficient combustion design and good operating practices". The applicant rejects an oxidation catalyst because it is technically infeasible for a recovery boiler due to poisoning from flue gas contaminants.

A review of EPA's RACT/BACT/LAER Clearinghouse shows previous CO BACT determinations ranging from 200 to 3000 ppmv. These determinations depend on the specified averaging period and age of the boiler. The recovery boilers and other industrial boilers at Georgia-Pacific's mills emit CO emissions ranging from 60 to 450 ppmv. The higher values are from older units with fewer than three levels of combustion air. The lower values are from units with three or more levels of combustion air. Test data shows that actual CO emissions from the existing No. 4 Recovery Boiler range from 102 to 756 ppmvd @ 8% O_2. The existing unit has current CO limits of 800 ppmvd @ 8% O_2 (3-hour average) and 400 ppmvd @ 8% O_2 (24-hour average), which were established as BACT in Permit No. AC54-266676 (PSD-FL-226) issued on September 21, 1995. The applicant proposes to retain these current CO emission limits based on the improved overfire air system and good combustion control.

A review of EPA's RACT/BACT/LAER Clearinghouse shows previous VOC BACT determinations ranging from 2.8 to 50 ppmv. Test data shows actual VOC emissions from the existing No. 4 Recovery Boiler ranging from 0.01 to 0.083 lbs/ton of BLS (2.0 to 15.9 ppmvd @ 8% O_2, respectively). The existing unit has current VOC limits of 0.30 lbs/ton BLS (31.5 lbs/hr and 138.0 TPY). These limits were established as BACT in Permit No. AC54-266676 (PSD-FL-226) issued on September 21, 1995. The applicant proposes to retain the current VOC emissions limits based on the improved overfire air system and good combustion control.

Department's CO/VOC BACT Reviews

It is recognized that oxidation catalysts have not been installed on boiler exhausts firing this type of fuel to control CO/VOC emissions. Therefore, the Department accepts proposed modification to add a 4th level of overfire combustion air as next best control option based on an efficient combustion design and good operating practices. According to the application, there is an optimum operating level for the BLS-to-air ratio. However, actual test results indicate a poor relationship between this ratio and CO emissions. This could be due to the manual control of the overfire air system and the variable air flow rates resulting from normal process fluctuations.

As previously mentioned, the existing unit has current CO limits of 800 ppmvd @ 8% O_2 (3-hour average) and 400 ppmvd @ 8% O_2 (24-hour average) based on annual stack tests, which were established as BACT in Permit No. AC54-266676 (PSD-FL-226) issued on September 21, 1995. Test data from the Department's ARMS database shows actual CO emissions from the existing recovery boiler ranging from approximately 35 to 510 ppmvd for a 3-hour test. Of the 15 tests reported, 11 three-hour test averages are below approximately 400 ppmvd. The Department's draft CO BACT determination is:

> As determined by data collected from the required continuous emissions monitoring system (CEMS), CO emissions from the recovery boiler shall not exceed 400 ppmvd @ 8% O_2 based on a 30-day rolling average excluding authorized periods of startup, shutdown, and equipment malfunctions.

The new CEMS-based standard will demonstrate continuous compliance and ensure the use of good combustion practices. The new standard will replace the previous CO standards and is believed to be more stringent due to the continuous compliance demonstration.

The existing recovery boiler has current VOC limits of 0.30 lbs/ton BLS (31.5 lbs/hr and 138.0 TPY), which were established as BACT in Permit No. AC54-266676 (PSD-FL-226) issued on September 21, 1995. Test data from the Department's ARMS database shows actual VOC emissions from the existing recovery boiler ranging from 0.01 to 0.083 lbs/ton BLS. Of the 14 tests submitted, all have been below 0.10 lbs/ton BLS. The addition of a 4th level of overfire air will provide improved combustion control. Therefore, the Department's draft BACT determination is 0.20 lb/ton BLS (21.0 lb/hour and 92.0 TPY) based on initial/renewal stack tests conducted at permitted capacity.

BACT Review for Sulfuric Acid Mist (SAM) Emissions

Discussion of SAM Emissions and Control Options

SO_3 emissions form as a byproduct of sulfur in the fuels fired, which can form sulfuric acid mist in the presence of water when the exhaust temperature drops below the dew point (~ 284° to 338° F). Sulfuric acid mist (SAM) emissions from recovery boilers are relatively low (approximately 2% to 4% of the SO_2 emissions) because these potential emissions are adsorbed as part of the smelt formed in the bottom of the furnace during combustion. There are three add-on control options that could be used to reduce SAM from the recovery boiler: wet scrubbers, wet ESPs, and mist eliminators. SAM emissions can be difficult to control because it is in a gaseous state in the recovery boiler exhaust at 425° F. Wet scrubbers and wet ESPs would be cost prohibitive given the low potential annual SAM emissions (15.9 tons/year) from the recovery boiler. Mist eliminators would not be very effective because sulfuric acid remains in the gaseous state at the temperature of the flue gas exhaust from the recovery boiler (~ 400° F).

Applicant's SAM BACT Review

A review of EPA's RACT/BACT/LAER Clearinghouse shows previous SAM BACT determinations range from 2.2 to 20 lbs/hr. BACT control technologies identified in the clearinghouse include: no controls, boiler design, firing rate and pulp production limits. The existing recovery boiler has a current limit of 0.81 ppmvd @ 8% O_2 (3.20 lbs/hr and 14.2 TPY), which was established in Permit No. AC54-266676 (PSD-FL-226) issued on September 21, 1995. Test data shows actual SAM emissions from the existing recovery boiler range from "none" reported in 2005 to 2.69 lbs/hr reported in 1998. The applicant proposes to retain the current SAM emissions limit of 0.81 ppmvd @ 8% O_2.

Department's SAM BACT Review

The Department accepts the applicant's proposal and establishes the draft SAM BACT determination as 0.81 ppmvd @ 8% O_2 based on initial/renewal stack tests. With the slight increase in the flue gas exhaust rate, the equivalent mass emission rates are 3.65 lbs/hr and 15.9 tons/year.

Summary of the Department's Draft BACT Determinations

The following table summarizes the Department's draft BACT determinations for the recovery boiler project.

Pollutant	Draft BACT Standards	Control Technology	Monitoring
PM/PM_{10}	0.030 grains/dscf @ 8% O_2	Electrostatic Precipitator (ESP)	Stack Test at Capacity
NO_x	80 ppmvd @ 8% O_2, 30-day rolling avg. (Excludes startup, shutdown, malfunction)	4-Level Overfire Air System Good Combustion Practices	CEMS
CO	400 ppmvd @ 8% O_2, 30-day rolling avg. (Excludes startup, shutdown, malfunction)	Good Combustion Practices	CEMS
SAM	0.81 ppmvd @ 8% O_2	Recovery Process	Stack Test at Capacity
VOC	0.20 lbs/ton BLS	Good Combustion Practices	Stack Test at Capacity (Surrogate: CO CEMS)

Note: Emission limits are based on either 294,000 dscfm @ 8% O_2 maximum flow rate or 210,000 lb/hr BLS maximum fuel feed rate.

4. Other Permit Conditions

The recovery boiler is already subject to the following applicable federal provisions: NSPS Subpart BB in 40 CFR 60 (Kraft Pulp Mills); and NESHAP Subpart MM (Combustion Sources at Kraft Pulp Mills) in 40 CFR 63. The recovery boiler is also subject to the applicable requirements of Rule 62-296.404 (Kraft Pulp Mills), F.A.C. These requirements are specified in the current Title V air operation permit.

The draft permit also includes the following limitations:

- As determined by data collected from the required continuous emissions monitoring system (CEMS), TRS emissions from the No. 4 Recovery Boiler shall not exceed 34.2 tons per consecutive 12 months.
- As determined by data collected from the required continuous emissions monitoring system (CEMS), SO_2 emissions from the No. 4 Recovery Boiler shall not exceed 153.9 tons per consecutive 12 months.
- The No. 4 Lime Kiln (Emissions Unit 017) is permitted to fire No. 6 fuel oil with a sulfur content that shall not exceed 2.10%, by weight, and it may include on-spec used oil.
- The No. 4 Combination Boiler (Emission Unit 016) is permitted to fire No. 6 fuel oil with a sulfur content that shall not exceed 2.10%, by weight, and it may include on-spec used oil.
- The maximum No. 6 fuel oil that may be fired by the No. 4 combination boiler is 5.03 million gallons per 12-months, rolling total.
- The permittee shall permanently shut down the existing No. 4 Power Boiler (Emission Unit 014).
- The draft permit will include a sufficient period of time to operate the new combustion air system and related gather operational and emissions data in the development of good combustion practices.

This project is based on a PSD netting analysis. In accordance with Rule 62-212.400(12)(Source Obligation), F.A.C., the applicant requested the above limitations to avoid PSD preconstruction review for SO_2 and TRS emissions.

5. AIR QUALITY ANALYSIS

Introduction

The proposed project will increase PM_{10}, NOx, CO, sulfuric acid mist (SAM), and VOC emissions at levels in excess of PSD significant amounts. PM_{10} and NOx are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels, and significant monitoring concentrations (de minimis concentrations) defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and a de minimis concentration defined for it. SAM is a non-criteria pollutant and has no standards, increments or significance levels defined for it; therefore, no air quality impact analysis was required for SAM. Instead, the BACT requirements will establish the SAM emission limit for this project. Potential VOC emissions increases are above the ambient impact analysis threshold of 100 TPY for the pollutant ozone. The applicant presented potential VOC emissions increases to the Department, and discussed available options to predict potential impacts associated with the emissions and formation of ozone, since no stationary point source models are available and approved for use in predicting ozone impacts. Based on the available information, the Department has determined that the use of a regional model that incorporates the complex chemical mechanisms for predicting ozone formation is not suitable for this project.

The air quality impact analyses required by the PSD regulations for this project include:

- An analysis of existing air quality for PM_{10}, NO_2, and VOC;
- A significant impact analysis for PM_{10}, NO_2, CO and VOC;
- A PSD increment analysis for PM_{10} and NO_2;
- An Ambient Air Quality Standards (AAQS) analysis for PM_{10} and NO_2;
- An analysis of impacts on soils, vegetation, and visibility and growth-related impacts to air quality.

Direction-specific building downwash parameters were used for all sources for which downwash impacts were considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

Based on the required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment.

Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. If available, existing representative monitoring data may be used to satisfy this monitoring requirement. An exemption to the monitoring requirement shall be granted by rule if either of the following conditions is met: the maximum predicted air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis ambient concentration; or the existing ambient concentrations are less than a pollutant-specific de minimis ambient concentration. If preconstruction ambient monitoring is exempted, determination of background concentrations for PSD significant pollutants with established AAQS may still be necessary for use in any required AAQS analysis. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from existing representative monitoring data. These background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of sources not included in the modeling. No de minimis ambient concentration is provided for ozone. Instead the net emissions increase of VOC is compared to a de minimis monitoring emission rate of 100 tons per year.

The table below shows maximum predicted project air quality impacts for comparison to these de minimis levels.

MAXIMUM PREDICTED PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE DE MINIMIS CONCENTRATIONS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than De Minimis? (Yes/No)**	**De Minimis Concentration ($\mu g/m^3$)**
PM_{10}	24-hr	7	NO	10
CO	8-hr	82	NO	575
NO_2	Annual	4	NO	14
VOC	Annual Emission Rate	389 TPY	YES	100 TPY

As shown in the table all pollutant emissions, with the exception of VOC are predicted to be less than the de minimis levels; therefore, preconstruction monitoring is not required for these pollutants. However, since VOC impacts from the project are predicted to be greater than the de minimis level; the applicant is not exempt from preconstruction monitoring for this pollutant. The applicant may instead satisfy the preconstruction monitoring requirement using previously existing representative data. These data do exist from ozone monitors located in the urbanized Alachua and Duval counties area to the west and north of the project. These data show no violation of any ozone standard. In addition PM_{10} and NOx data has been collected in the Palatka and Jacksonville areas, respectively. These data are appropriate to establish background concentrations for use in the PM_{10} and NOx AAQS analyses. The background concentrations for these pollutants are shown in the table below.

BACKGROUND CONCENTRATIONS FOR USE IN AAQS ANALYSES		
Pollutant	**Averaging Time**	**Background Concentration ($\mu g/m^3$)**
PM_{10}	Annual	27
	24-hour	57
NO_2	Annual	28

Models and Meteorological Data Used in Significant Impact, PSD Increment and AAQS Analyses

PSD Class II Area Model

The EPA-approved American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model was used to evaluate the pollutant emissions from the proposed project and other existing major facilities. In November, 2005, the EPA promulgated AERMOD as the preferred regulatory model for predicting pollutant concentrations within 50 km from a source. AERMOD is a replacement for the Industrial Source Complex Short-Term Model (ISCST3). The AERMOD model calculates hourly concentrations based on hourly meteorological data. For evaluating plume behavior within the building wake of structures, the AERMOD model incorporates the Plume Rise Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). AERMOD can predict pollutant concentrations for annual, 24, 8, 3 and 1-hour. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario.

Meteorological data used in the AERMOD model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the Jacksonville International Airport and Waycross, Georgia, respectively (surface and upper air data). The 5-year period of meteorological data was from 1986 through 1990. These stations were selected for use in the evaluation because they are the closest primary weather stations to the project area and are most representative of the project site.

Because five years of data are used in AERMOD, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility, and for determining if there are significant impacts occur from the project on any PSD Class I area, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators.

PSD Class I Area Model

Since the closest PSD Class I areas, the Okefenokee National Wilderness Area (NWA), the Chassahowitzka NWA and Wolf Island NWA are greater than 50 km from the proposed facility, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and on the Air Quality Related Values (AQRV): regional haze and nitrogen and sulfur deposition. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. Meteorological data were obtained and processed for the calendar years of 1990, 1992 and 1996, the years for which MM4 and MM5 data are available. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the federal land managers.

Receptor Grids for Performing PSD Increments and AAQS Analyses

For the PSD Class II increment and AAQS analyses, receptor grids normally are based on the size of the significant impact area for each pollutant. As shown in the previous section, the sizes of the significant impact areas for the required PM10 and NO_2, analyses were 0.80 and 1.75 km, respectively.

Significant Impact Analysis

Preliminary modeling is conducted using only the proposed project's worst-case emission scenario for each pollutant and applicable averaging time. Over 2000 receptors were placed along the facility's restricted property line and out to 4 km from the facility, which is located in a PSD Class II area. Three PSD Class I areas are located within 200 km of the project: the Okefenokee NWA, 108 km to the north of the Mill, the Chassahowitzka NWA located 137 km southwest of the Mill and the Wolf Island NWA located 186 km to the north of the project. A total of 180, 58 and 30 receptors were placed in the Okefenokee NWA, Chassahowitzka NWA and Wolf Island NWA PSD Class I areas, respectively. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project were predicted in a PSD Class II area in the vicinity of the facility or in any PSD Class I area. In the event that the maximum predicted impact of a proposed project is less than the appropriate significant impact level, a full impact analysis for that pollutant is not required. Full impact modeling is modeling that considers not only the impact of the project but also other major sources, including background concentrations, located within the vicinity of the project to determine whether all applicable AAQS or PSD increments are predicted to be met for that pollutant. Consequently, a preliminary modeling analysis, which shows an insignificant impact, is accepted as the required air quality analysis (AAQS and PSD increments) for that pollutant and no further modeling for comparison to the AAQS and PSD increments is required for that pollutant. The tables below show the results of this modeling. The radius of significant impact, if any, for each pollutant and applicable pollutant averaging time is also shown in the tables below.

MAXIMUM PREDICTED PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY					
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact?**	**Radius of Significant Impact (km)**
PM_{10}	Annual	2	1	YES	0.80
	24-hr	7	5	YES	0.80
CO	8-hr	82	500	NO	----
	1-hr	93	2,000	NO	----
NO_2	Annual	4	1	YES	1.75
VOC	AER	389 TPY	100 TPY	YES	----

MAXIMUM PREDICTEDPROJECT IMPACTS IN THE PSD CLASS I AREAS FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact? (ug/m^3)**
PM_{10}	Annual	0.002	0.2	NO
	24-hr	0.04	0.3	NO
NO_2	Annual	0.004	0.1	NO

As shown in the tables, the maximum predicted air quality impacts due to PM_{10} and NO_2 emissions from the proposed project are greater than the PSD Class II significant impact levels in the vicinity of the facility. Therefore, the applicant was required to do full impact PM_{10} and NO_2 modeling in the vicinity of the facility, within the applicable significant impact area, to determine the impacts of the project along with all other sources in the vicinity of the facility. The significant impact area in the vicinity of the facility is based upon the predicted radius of significant impact. Less than significant impacts were predicted for CO in the Class II area in the vicinity of the project, and for PM_{10} and NO_2 in the Class I areas; therefore, no further dispersion modeling was required to be performed for these pollutants in these areas. In addition, potential VOC emissions increases are above the ambient impact analysis threshold of 100 TPY for the pollutant ozone. As stated in the introduction to the air quality impact analysis section, the applicant presented potential VOC emissions increases to the Department, and discussed available options to predict potential impacts associated with the emissions and formation of ozone, since no stationary point source models are available and approved for use in predicting ozone impacts. Based on the available information, the Department has determined that the use of a regional model that incorporates the complex chemical mechanisms for predicting ozone formation is not suitable for this project.

PSD Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration which was established in 1977 for PM_{10} and SO_2 (the baseline year was 1975 for existing major sources of PM_{10} and SO_2), and 1988 for NO_2 (the baseline year was 1988 for existing major sources of NO_2). The emission values that are input into the model for predicting increment consumption are based on maximum emissions from increment-consuming facility sources and all other increment-consuming sources in the vicinity of the facility. The maximum predicted PSD Class II area PM_{10} and NO_2 increments consumed by this project and all other increment-consuming sources in the vicinity of the facility are shown below. The results show that all of the maximum predicted impacts are less than the allowable increments.

PSD CLASS II INCREMENT ANALYSIS				
Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Impact Greater than Allowable Increment?	Allowable Increment ($\mu g/m^3$)
PM_{10}	Annual	0	No	17
	24-hourr	6	No	30
NO_2	Annual	7	No	25

AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the maximum-modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The results of the AAQS analysis are summarized in the table below. As shown in this table, emissions from the proposed facility are not expected to cause or significantly contribute to a violation of any AAQS.

MAXIMUM AMBIENT AIR QUALITY IMPACTS						
Pollutant	Averaging Time	Modeled Sources ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater than AAQS	AAQS ($\mu g/m^3$)
PM_{10}	Annual	9	27	36	No	50
	24-hour	30	57	87	No	150
NO_2	Annual	14	28	42	No	100

Additional Impacts Analysis

Impacts on Soils, Vegetation, Wildlife, and Visibility

The maximum ground-level concentrations predicted to occur due to PM10, NOx and CO emissions as a result of the proposed project, including all other nearby sources, will be below the associated AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area. An air quality related values (AQRV) analysis was done by the applicant for the Class I area. No significant impacts on this area are expected. A regional haze analysis using the long-range transport model CALPUFF was done for the PSD Class I areas. This analysis showed no significant impact on visibility in this area. Total nitrogen (N) and sulfur (S) deposition rates on the PSD Class I areas were also predicted using CALPUFF. The maximum predicted deposition rates are below the federal land manager recommended deposition threshold levels for N and S

Growth-Related Air Quality Impacts

The proposed modification will not significantly change employment, population, housing or commercial/industrial development in the area to the extent that a significant air quality impact will result.

6. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. Bruce Mitchell is the project engineer responsible for reviewing the application and drafting the permit changes. Cleve Holladay is the meteorologist responsible for reviewing the ambient air quality analyses. Jeff Koerner, P.E. is the Air Permitting Supervisor who reviewed the draft permit package. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

Georgia-Pacific Corporation
Palatka Mill

Facility ID No.: 1070005
Putnam County

Air Construction Permit Project No.: 1070005-035-AC/PSD-FL-367

No. 4 Recovery Boiler Modification

<u>Permitting Authority:</u>
State of Florida
Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979
Fax: 850/921-9533

<u>Compliance Authority:</u>
Department of Environmental Protection
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, Florida 32256
Telephone: 904/807-3300-4900
Fax: 904/448-4319

PERMITTEE:

Georgia-Pacific Corporation
Post Office Box 919
Palatka, Florida 32178-0919

I.D. Number:	1070005
Permit Number:	1070005-035-AC PSD-FL-367
Date of Issue:	Month Day, 2006
Expiration Date:	May 31, 2008
County:	Putnam
Project:	#4 Recovery Boiler Modification

This permit authorizes the modification of the existing No. 4 Recovery Boiler, which involves an extensive replacement of several tubes, replacement or changes of the combustion air systems (including adding a fourth combustion air system), addition of a crystallizer and associated storage/flash tank, and miscellaneous changes (i.e., baffles, heat exchanger, piping, etc.) to the two concentrators associated with the No. 4 multiple effect evaporator set. These changes will occur at the existing Georgia-Pacific Corporation's Palatka Mill located North of County Road 216 and West of U.S. Highway 17, Palatka, Putnam County, Florida. UTM Coordinates: Zone 17; 434.0 km East; and, 3283.4 km North; Latitude: 29° 41' 00" North; and, Longitude: 81° 40' 4" West.

STATEMENT OF BASIS: This air construction permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Initial Title V Air Operation Permit Project No. 1070005-002-AV
APPENDIX A. Citation Formats
APPENDIX C. Common State Requirements
APPENDIX BD. Summary of Final BACT Determinations
APPENDIX SS-1, STACK SAMPLING FACILITIES (dated 10/07/96)
TABLE 297.310-1, CALIBRATION SCHEDULE (dated 10/07/96)
Attachment "40 CFR 63, Subpart A"

Michael G. Cooke, Director
Division of Air Resource Management

MGC/tlv/bm

GENERAL CONDITIONS

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of the conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does no relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permitted to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any record that must be kept under the conditions of the permit;
b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and
c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a. A description of and cause of non-compliance; and,
b. The period of non-compliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, F.S. Such

evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

- (x) Determination of Best Available Control Technology (BACT)
- (x) Determination of Prevention of Significant Deterioration (PSD)
- ( ) Compliance with New Source Performance Standards (NSPS)
- (x) Compliance with National Emission Standards for Hazardous Air Pollutants/ Maximum Available Control Technology (MACT)

14. The permittee shall comply with the following:

a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurement;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS

A. No. 4 Recovery Boiler (Emissions Unit -018). The No. 4 Recovery Boiler has a maximum steam production capacity of 789,000 lbs/hr (24-hour average) based on steam conditions of 850° F – 900° F at 1250 psi. The primary fuel is black liquor solids (BLS). Particulate matter emissions are controlled by a 2-chamber, 6 field/chamber electrostatic precipitator (ESP) with automatic voltage control. Total reduced sulfur emissions are reduced by the low odor design. NOx emissions are control by a 4-level overfire air system. CO and VOC emissions are controlled by good operating practices. Exhaust gases exit at approximately 400° F from a 12' diameter stack that is 230' tall.

This emissions unit is regulated under Rule 62-296.404(Kraft Pulp Mills), F.A.C. Rule 212.400(PSD), F.A.C.; Permit No. PSD-FL-226; Rule 62-210.200(BACT), F.A.C.; 40 CFR 60, NSPS Subpart BB (Kraft Pulp Mills); and 40 CFR 63, NESHAP Subpart MM (Chemical Recovery Combustion Sources at Kraft Pulp Mills). NSPS and NESHAP provision are already incorporated into the Title V air operation permit for this unit.

The following specific conditions apply to the emissions unit listed above:

General.

A.0. This permit authorizes the modification of the No. 4 Recovery Boiler based on the following preliminary schedule: modify combustion air system, replace portion of recovery boiler tubes, and start construction of new crystallizer and upgrades to concentrator/evaporator (May 2006); replace tubes in superheater, economizer, and walls of recovery boiler (April/May of 2007); and startup of new crystallizer/evaporator (May 2008). The modification to the existing combustion air system shall add a fourth level of combustion air (quaternary air). The project will not increase the maximum capacity of the recovery boiler or the pulp mill (118 tons/hour ADUP and 1850 tons/day ADUP, monthly average). [Rule 62-210.300(1), F.A.C.]

A.1. The term "Administrator" shall mean the "Secretary of the Department of Environmental Protection" or its designee.

A.2. NESHAP Applicability.
a. 40 CFR 63, Subpart MM, National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills, shall apply to the emissions unit described herein.
b. 40 CFR 63, Subpart A, General Provisions, shall apply to the emissions unit described herein.
[Rule 62-204.800, F.A.C.]

Operational Parameters.

A.3. Permitted Capacity.
a. The maximum throughput rate of black liquor solids (BLS) is 210,000 lbs/hr (24-hour average) and 5.04 x 10^{+6} lb/day.
b. The maximum exhaust gas flow rate is 294,000 dscfm at 8% oxygen.
c. The maximum steam production rate is 789,000 lbs/hr (24-hour average) based on steam conditions of 850° F – 900° F at 1250 psi.
a. BLS: The maximum heat input from firing BLS is 1,345 MMBtu/hr (based on 210,000 lbs/hr of BLS at 6,410 Btu/lb BLS).
b. No. 6 Fuel Oil. The No. 4 Recovery Boiler is permitted to fire #6 fuel oil with a sulfur content that shall not exceed 2.10%, by weight, and it may include on-spec used oil. Under normal operating conditions, fuel oil shall only be fired when there is a loss of BLS and there is a need for steam that cannot be acquired from the other power boilers. The permittee is authorized to fire any fuel oil remaining in the tank, but shall only add fuel oil meeting the new fuel sulfur specification after issuance of this permit.
c. Natural Gas. Natural gas may be fired as start-up fuel.
d. On-Specification Used Oil. The on-specification used oil fired in the recovery boiler shall not exceed 10% of the fuel consumed and shall be blended with the No. 6 fuel oil. The on-spec used oil prior to blending shall comply with the limits listed below, the provisions of 40 CFR 279 & 761 and shall be recorded:

ON-SPEC USED OIL SPECIFICATIONS	
Constituent/Property	Allowable Level
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum

ON-SPEC USED OIL SPECIFICATIONS	
Lead	100 ppm maximum
Total Halogens	1,000 ppm maximum
Flash Point	100°F minimum

(1) On-specification used oil may be fired as follows:

- At any time provided the maximum concentration of PCBs shall be less than 2 ppm and whether generated on or off-site. The analysis and recordkeeping requirements apply to each amount prior to blending even if to be blended with 90% virgin oil.
- Only during normal operation temperature and not during startup or shutdown if the maximum concentration is:
- $2 \leq$ PCB < 50 ppm.
- Blended oils shall not exceed 2.10% sulfur by weight.

(2) On-specification used oil test requirements are approved EPA, DEP or ASTM test methods and shall be used or a certified on-specification used oil analysis shall be obtained prior to blending and shall be retained for inspection or submitted to the Department on request.

[Rule 62-213.410, F.A.C.; 1070005-017-AC; and, 1070005-035-AC/PSD-FL-367]

A.5. Hours of Operation. The hours of operation are not limited.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, 1070005-035-AC/PSD-FL-367]

Emission Limitations and Standards.

Unless otherwise specified, the averaging times for specific conditions A.6. through A.13. are based on the specified averaging time of the applicable test method. A summary of the BACT determinations for the recovery boiler is provided in Appendix BD.

A.6. Particulate Matter (PM as PM/PM_{10}). The permittee shall operate and maintain an electrostatic precipitator (ESP) to control particulate matter emissions. Except for infrequent periods of maintenance, all fields of the ESP shall be functioning when the recovery boiler is in operation. Total PM emissions, including HAP metal emissions, shall not exceed 0.030 grains/dscf at 8% O_2, 75.6 lbs/hr and 331.1 TPY, based on the average of three (3) test runs conducted in accordance with EPA Reference Method 5 or 29, 40 CFR 60, Appendix A.

{Permitting Note: Compliance with the above limits ensure compliance with the applicable NESHAP limit in 40 CFR 63, Subpart MM, of 0.044 grains/dscf at 8% O_2.}

[Rules 62-210.200(BACT), 62-212.400(PSD) and 62-297.310(7)(a)4.b. & c., F.A.C.; 40 CFR 60, Appendix A; 40 CFR 63.862(a)(1)(i)(C); and, 1070005-035-AC/PSD-FL-367]

A.7. Total Reduced Sulfur (TRS). As determined by data collected from the required continuous emissions monitoring system (CEMS) for compliance purposes, TRS emissions shall not exceed:
a. 11.2 ppmvd @ 8% O_2 and 17.5 lb/hour based on a 12-hour block average as H_2S (consistent with the averaging period defined in Rule 62-296.404, F.A.C.);
b. 5.0 ppmvd @ 8% O_2 based on a 12-month rolling average; and
c. 34.2 tons per consecutive 12 months, rolling total.
[Rules 62-210.200(BACT), 62-212.400(PSD), 62-296.404(3)(e)1, Rule 62-212.400(12)(Source Obligation), F.A.C.; and, 1070005-035-AC/PSD-FL-367]

A.8. Sulfur Dioxide (SO_2). As determined by data collected from the required continuous emissions monitoring system (CEMS) for compliance purposes, SO_2 emissions (including periods of startup, shutdown and malfunctions) shall not exceed the following:
a. 37.5 ppmvd @ 8% O_2 and 109.9 lbs/hr based on a 24-hr rolling average;
b. 12.0 ppmvd @ 8% O_2 based on a 12-month rolling average; and

c. 153.9 tons per consecutive 12 months, rolling total.
{Permitting Note: Modeling of SO_2 emissions were also based on a 3-hour average 37.5 ppmvd @ 8% O_2.}
[Rules 62-210.200(BACT), 62-212.400(PSD), 62-212.400(12)(Source Obligation), and 62-297.310(7)(a)4.b., F.A.C.; and, 1070005-035-AC/PSD-FL-367]

A.9. Nitrogen Oxides (NO_x). As determined by data collected from the required continuous emissions monitoring system (CEMS) for compliance purposes, NOx emissions (excluding authorized periods of startup, shutdown and malfunctions) shall not exceed 80 ppmvd corrected to 8% O_2 based on a 30-day rolling average.
{Permitting Note: The equivalent mass emissions rates are 168.5 lbs/hr and 738.1 TPY.}
[Rules 62-210.200(BACT), 62-212.400(PSD) and 62-297.310(7)(a)4.b., F.A.C.; and, 1070005-035-AC/PSD-FL-367]

A.10. Carbon Monoxide (CO). As determined by data collected from the required continuous emissions monitoring system (CEMS) for compliance purposes, CO emissions (excluding authorized periods of startup, shutdown and malfunctions) shall not exceed 400 ppmvd @ 8% O_2 based on a 30-day rolling average.
{Permitting Note: The equivalent mass emissions rates are 512.7 lb/hour and 2,245.6 TPY.}
[Rules 62-210.200(BACT), 62-212.400(PSD) and 62-297.310(7)(a)4.b., F.A.C.; and, 1070005-035-AC/PSD-FL-367]

A.11. Volatile Organic Compounds (VOC). As determined by EPA Reference Method 25A (40 CFR 60, Appendix A), VOC emissions shall not exceed 0.20 lbs/ton BLS and 21.0 lbs/hour based on the average of three (3) test runs.
{Permitting Note: The equivalent annual mass emissions rate is 92.0 TPY.}
[Rules 62-210.200(BACT), 62-212.400(PSD) and 62-297.310(7)(a)4.b.; and, 1070005-035-AC/PSD-FL-367]

A.12. Sulfuric Acid Mist (SAM). As determined by EPA Reference Method 8 (40 CFR 60, Appendix A), SAM emissions shall not exceed 0.81 ppmvd @ 8% O_2 and 3.6 lbs/hr and 15.9 TPY, based on the average of three (3) test runs.
{Permitting Note: The equivalent annual mass emissions rate is 15.9 TPY.}
[Rules 62-210.200(BACT), 62-212.400(PSD) and 62-297.310(7)(a)4.b., F.A.C.; and, 1070005-035-AC/PSD-FL-367]

A.13. Visible Emissions (VE). As determined by the required continuous opacity monitoring system (COMS) for compliance purposes or EPA Reference Method 9 (40 CFR 60, Appendix A), visible emissions shall not exceed 20% opacity based on a 6-minute block average.
[Rules 62-210.200(BACT), 62-212.400(PSD) and 62-297.310(7)(a)4.a., F.A.C.; 40 CFR 63.864(d); and, 1070005-035-AC/PSD-FL-367]

Excess Emissions.

Rule 62-210.700(Excess Emissions), F.A.C. cannot vary any federal NSPS or NESHAP provision.

A.14. Startup, Shutdown and Malfunction.
a. Startup or Shutdown. Excess emissions resulting from startup or shutdown shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed eight (8) hours in any 24 hour period unless specifically authorized by the Department for longer duration. The ESP shall be brought on line as soon as feasible. The recovery boiler shall comply with the visible emissions standard of this permit when the ESP is fully operational.
[Rule 62-210.700, F.A.C.; Permit No. 1070005-017-AC]

b. Malfunction. Excess emissions resulting from malfunction shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two (2) hours in any 24-hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

c. Definitions. Rules 62-210.200(159), (230) and (245), F.A.C. define the following terms.

a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.

c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

A.15. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Test Methods and Procedures.

A.16. PM.
a. BACT. Total PM emissions (including HAP metals) stack testing shall comply with the applicable requirements in Rule 62-297.401, F.A.C. (EPA Reference Method 5 or 29, to measure PM concentration, EPA Reference Methods 1 through 4 for volumetric flow rate measurements, and EPA Reference Method 3A or 3B for oxygen concentration to calculate the oxygen-corrected PM concentration, incorporated and adopted by reference in Chapter 62-297, F.A.C.). The tests shall be performed initially and once each federal fiscal year. Opacity data for each test run from the required COMS shall be included with the test report. If requested by the Department, the permittee shall conduct a PM test to demonstrate compliance with the PM emission standard with the ESP functioning on the number of fields operated when performing maintenance during the federal fiscal year.
[Rules 62-212.400(BACT) and 62-297.310(7)(a)4.b., F.A.C.; and, 1070005-035-AC/PSD-FL-367]

b. NESHAP. (Initial compliance testing has already been conducted: August 26-27, 2004)
(a) Not applicable.
(b) The owner or operator seeking to determine compliance with 40 CFR 63.862(a) (see specific condition No. 6), must use the procedures in paragraphs 40 CFR 63.865(b)(1) through (6).

(1) For purposes of determining the concentration or mass of PM emitted from each Kraft or soda recovery boiler, Method 5 or 29 in Appendix A of 40 CFR Part 60 must be used, except that Method 17 in Appendix A of 40 CFR Part 60 may be used in lieu of Method 5 or Method 29 if a constant value of 0.009 g/dscm (0.004 grains/dscf) is added to the results of Method 17, and the stack temperature is no greater than 205 °C (400 °F). For Methods 5, 29, and 17, the sampling time and sample volume for each run must be at least 60 minutes and 0.90 dscm (31.8 dscf), and water must be used as the cleanup solvent instead of acetone in the sample recovery procedure.

(2) For sources complying with 40 CFR 63.862(a), the PM concentration must be corrected to the appropriate oxygen concentration using Equation 7 of this section as follows:

$$C_{corr} = C_{meas} \times (21 - X)/(21 - Y) \qquad \text{(Eq. 7)}$$

Where:

C_{corr} = the measured concentration corrected for oxygen, g/dscm (grains/dscf).
C_{meas} = the measured concentration uncorrected for oxygen, g/dscm (grains/dscf).
X = the corrected volumetric oxygen concentration (8 percent for Kraft or soda recovery furnaces).
Y = the measured average volumetric oxygen concentration.

(3) Method 3A or 3B in Appendix A of 40 CFR Part 60 must be used to determine the oxygen concentration. The voluntary consensus standard ANSI/ASME PTC 19.10-1981--Part 10 (incorporated by reference--see 40 CFR 63.14) may be used as an alternative to using Method 3B. The gas sample must be taken at the same time and at the same traverse points as the particulate sample.
(4) Not applicable.
(5)(i) For purposes of selecting sampling port location and number of traverse points, Method 1 or 1A in Appendix A of 40 CFR Part 60 must be used;

(ii) For purposes of determining stack gas velocity and volumetric flow rate, Method 2, 2A, 2C, 2D, 2F, or 2G in appendix A of 40 CFR part 60 must be used;
(iii) For purposes of conducting gas analysis, Method 3, 3A, or 3B in Appendix A of 40 CFR Part 60 must be used.

The voluntary consensus standard ANSI/ASME PTC 19.10-1981--Part 10 (incorporated by reference--see 40 CFR 63.14) may be used as an alternative to using Method 3B; and

(iv) For purposes of determining moisture content of stack gas, Method 4 in Appendix A of 40 CFR Part 60 must be used.

(6) Process data measured during the performance test must be used to determine the black liquor solids firing rate on a dry basis and the CaO production rate.

[40 CFR 63.865(b)(1) thru (3), (5) & (6)]

c. The tests shall be performed initially and once each federal fiscal year.
[Rules 62-210.200(BACT), 62-212.400(PSD NSR and BACT) and 62-297.310(7)(a)4.b. & c., F.A.C.; and, 1070005-035-AC/PSD-FL-367]

A.17. TRS. Compliance shall be demonstrated by the required CEMS. If required, TRS emissions stack testing shall comply with the applicable requirements in Rule 62-297.401, F.A.C. (EPA Reference Method 16 or 16A, to measure TRS concentration; EPA Reference Methods 1 through 4 for volumetric flow rate measurements; and EPA Reference Method 3A or 3B for oxygen concentration to calculate the oxygen-corrected TRS concentration, incorporated and adopted by reference in Chapter 62-297, F.A.C.).
[Rules 62-212.400(BACT) and 62-297.310(7)(a)4.b., F.A.C.; and, 1070005-035-AC/PSD-FL-367]

A.18. SO_2. Compliance shall be demonstrated by the required CEMS. If required, SO_2 emissions testing shall comply with Rule 62-297.401, F.A.C. (EPA Reference Method 8 to measure the SO_2 concentration and EPA Reference Methods 1 through 4 to measure the volumetric flow rate and EPA Reference Method 3A or 3B shall be used to measure the oxygen concentration to calculate the oxygen-corrected SO_2 concentration, incorporated and adopted by reference in Chapter 62-297, F.A.C.).
[Rules 62-212.400(BACT) and 62-297.310(7)(a)4.b., F.A.C.; and, 1070005-035-AC/PSD-FL-367]

A.19. NO_x. Compliance shall be demonstrated by the required CEMS. If required, NO_x emissions testing shall comply with Rule 62-297.401, F.A.C. (EPA Reference Method 7E shall be used to measure the NO_x concentration, EPA Reference Methods 1 through 4 shall be used to measure the volumetric flow rate and EPA Reference Method 3A or 3B shall be used to measure the oxygen concentration to calculate the oxygen-corrected NO_x concentration, incorporated and adopted by reference in Chapter 62-297, F.A.C.).
[Rules 62-212.400(BACT) and 62-297.310(7)(a)4.b., F.A.C.; and, 1070005-035-AC/PSD-FL-367]

A.20. CO. Compliance shall be demonstrated by the required CEMS. If required, CO emissions testing shall comply with Rule 62-297.401, F.A.C. (EPA Reference Method 10 shall be used to measure the CO concentration, EPA Reference Methods 1 through 4 shall be used to measure the volumetric flow rate and EPA Reference Method 3A or 3B shall be used to measure the oxygen concentration to calculate the oxygen-corrected CO concentration, incorporated and adopted by reference in Chapter 62-297, F.A.C.).
[Rules 62-212.400(BACT) and 62-297.310(7)(a)4.b., F.A.C.; and, 1070005-035-AC/PSD-FL-367]

A.21. SAM. SAM emissions testing shall comply with Rule 62-297.401, F.A.C. (EPA Reference Method 8 of NCASI Method 106 to measure the SAM concentration and EPA Reference Methods 1 through 4 to measure the volumetric flow rate and EPA Reference Method 3A or 3B shall be used to measure the oxygen concentration to calculate the oxygen-corrected SAM concentration, incorporated and adopted by reference in Chapter 62-297, F.A.C.). The test shall be performed initially and prior to each permit renewal.
[Rules 62-212.400(BACT) and 62-297.310(7)(a)4.b., F.A.C.; and, 1070005-035-AC/PSD-FL-367]

A.22. VOC. VOC emissions testing shall comply with Rule 62-297.401(25)(a), F.A.C. (EPA Reference Method 25A to measure the total hydrocarbon concentration, EPA Methods 1 through 4 to measure the volumetric flow rate, incorporated and adopted by reference in Chapter 62-297, F.A.C.). The test shall be performed initially and prior to each permit renewal.
[Rules 62-212.400(BACT) and 62-297.310(7)(a)4.b., F.A.C.; 3/11/93 Alternate Procedures and Requirements Order; and, 1070005-035-AC/PSD-FL-367]

SPECIFIC CONDITIONS

A.23. VE. Compliance shall be demonstrated by the required COMS. If required, VE testing shall comply with Rule 62-297.401, F.A.C. (EPA Reference Method 9 shall be used to measure the opacity, incorporated and adopted by reference in Chapter 62-297, F.A.C.).
[Rules 62-212.400(BACT) and 62-297.310(7)(a)4.a., F.A.C.; and, 1070005-035-AC/PSD-FL-367]

A.24. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

A.25. Operating Rate During Testing. Testing of emissions shall be conducted with each emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

A.26. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

A.27. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute; and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1 (attached).
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

A.28. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

A.29. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
    a. Did not operate.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
    a. Visible emissions, if there is an applicable standard;
    b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; or, 100 tons per year or more of any other regulated air pollutant; and,
    c. Each NESHAP pollutant, if there is an applicable emission standard.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.
[Rule 62-297.310(7), F.A.C.; and, SIP approved]

(c) Initial Compliance Stack Tests: After completing the recovery boiler modifications, initial compliance with the emissions standards for PM, SAM, and VOC shall be demonstrated within 60 days of achieving the permitted capacity (210,000 lb/hour of BLS), but no later than 180 days of initial startup. [Rules 62-4.070(3) and 62-297.310(7), F.A.C.]

Monitoring Requirements.

A.30. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Continuous Monitoring Requirements.

A.31. Continuous Flow Monitor. A continuous flow monitor shall be installed to determine the stack exhaust flow rate to be used in determining mass emission rates. The flow monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 6. [Rules 62-4.070(3) and 62-297.520, F.A.C.; and, 40 CFR 60, Appendix B, Performance Specification 6]

A.32. Continuous Emissions Monitoring System (CEMS). The permittee shall install, calibrate, operate and maintain a CEMS to measure and record concentrations of sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO) and total reduced sulfur (TRS) in the exhaust stack of the recovery boiler in a manner sufficient to demonstrate continuous compliance with the emissions standards specified in this section.
[Rules 62-4.070(3), 62-212.400(BACT), 62-296.404(5) and 62-297.520, F.A.C.; 40 CFR 60, Appendix B, Performance Specifications 2, 4 or 4B, 5 and 6; 40 CFR 60, Appendix F; and, 1070005-035-AC/PSD-FL-367]

A.33. Diluent Oxygen (O_2) CEMS Requirements. The permittee shall install, calibrate, operate and maintain a CEMS to measure and record the concentration of oxygen (O_2) to correct measured CO, SO_2 and TRS emissions to the required oxygen concentration. The O_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification(s) 3 and/or 4B. The CEMS shall be installed and functioning within the required performance specifications by the time of the initial performance tests.
[Rules 62-4.070(3), 62-296.404(5) and 62-297.520, F.A.C.; and, 40 CFR 60, Appendix B, Performance Specification(s) 3 and/or 4B]

A.34. SO_2: CEMS Requirements. The SO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 2. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The required RATA tests shall be performed using EPA Reference Method 6C in Appendix A, 40 CFR 60. The SO_2 monitor span values shall be set appropriately, considering the expected range of emissions and corresponding emission standards.
[Rules 62-4.070(3) and 62-297.520, F.A.C.; 40 CFR 60, Appendix A; 40 CFR 60, Appendix B, Performance Specification 2; and, 40 CFR 60, Appendix F]

A.35. NO_x: CEMS Requirements. The NO_x monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 2. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The required RATA tests shall be performed using EPA Reference Method 7 or 7E in Appendix A, 40 CFR 60. The NO_x monitor span values shall be set appropriately, considering the expected range of emissions and corresponding emission standards.
[Rules 62-4.070(3) and 62-297.520, F.A.C.; 40 CFR 60, Appendix A; 40 CFR 60, Appendix B, Performance Specification 2; and, 40 CFR 60, Appendix F]

A.36. CO: CEMS Requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4B. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The required RATA tests shall be performed using EPA Reference Method 10 in Appendix A, 40 CFR 60. The CO monitor span values shall be set appropriately, considering the expected range of emissions and corresponding emission standards.
[Rules 62-4.070(3), 62-212.400(BACT) and 62-297.520, F.A.C.; 40 CFR 60, Appendix A; 40 CFR 60, Appendix B, Performance Specification 4 or 4B; and, 40 CFR 60, Appendix F]

A.37. TRS: CEMS Requirements. (a) A TRS continuous monitoring system for monitoring TRS emissions shall comply with the applicable requirements in Rule 62-296.404(5)(b), F.A.C., as follows:
(b) Continuous Determination of Total Reduced Sulfur Emissions.
1. A total reduced sulfur continuous emissions monitoring system shall be installed, calibrated, certified and operated pursuant to all of the following provisions:
a. The continuous emissions monitoring system shall monitor and record the concentration of total reduced sulfur (TRS) emissions on a dry basis and the percentage of oxygen by volume on a dry basis.
b. The continuous emissions monitoring system shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
c. The continuous emissions monitoring system shall be located downstream of the control device such that representative measurements of process parameters can be obtained.
d. The continuous emissions monitoring system shall be located, installed and certified pursuant to the provisions of 40 C.F.R. Part 60, Appendix B, Performance Specification 2 and Performance Specification 3, and 40 C.F.R. Part 60, Appendix B, Performance Specification 5, which are adopted by reference in subsection 62-204.800(7), F.A.C. The exception is that the phrase "or other approved alternative" in Section 3.2 of Performance Specification 5 is not adopted. For the purposes of compliance testing and certification of continuous emissions monitoring systems, 40 C.F.R. Part 60, Appendix A, Reference Method 16 and Method 16A, adopted by reference in subsection 62-204.800(7), F.A.C., are to

be used.

e. The continuous emissions monitoring system shall be in continuous operation, except when the emissions unit is not operating, or during system breakdowns, repairs, calibration checks, and zero and span adjustments.

f. During any initial compliance tests conducted pursuant to Rule 62-296.404, F.A.C., or within 30 days thereafter, and at such times as there is reason to believe the system does not conform to the performance specifications under this rule (for example, equipment repairs, replacements, excessive drift and such), the owner or operator of any affected emissions unit shall conduct continuous monitoring system performance evaluations and furnish the Department, within sixty days thereof, two copies of a written report of the results of such tests. These continuous emissions monitoring systems performance evaluations shall be conducted in accordance with the requirements and procedures contained in sub-subparagraph 62-296.404(5)(b)1.d., F.A.C.

g. The continuous emissions monitoring system shall have a maximum span value not to exceed:

(i) A total reduced sulfur concentration of 30 ppm for the total reduced sulfur continuous emissions monitoring system on any new design direct-fired Kraft recovery furnace that is not a direct-fired, new design suspension-burning Kraft recovery furnace.

(ii) A total reduced sulfur concentration of 50 ppm for the total reduced sulfur continuous emissions monitoring system on any old design Kraft recovery furnace, new design Kraft recovery furnace that is not a direct-fired, new design direct-fired suspension-burning Kraft recovery furnace.

(iii) 20 percent oxygen for the continuous oxygen monitoring system.

h. The continuous emissions monitoring system shall be checked by the owner or operator in accordance with a written procedure at least once daily and after any maintenance to the system. The owner or operator shall check the zero (or low level value between 0 and 20 percent of span value) and span (90 to 100 percent of span value) calibration drifts. The zero and span shall be adjusted, as a minimum, whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications referenced in sub-subparagraph 62-296.404(5)(b)1.d., F.A.C. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified.

2. The owner or operator of any total reduced sulfur emissions unit who is required to install a total reduced sulfur continuous emissions monitoring system pursuant to paragraph 62-296.404(5)(a), F.A.C., shall:

a. Reduce all data to one-hour averages for each 60-minute period beginning on the hour. One-hour averages shall be computed from a minimum of four data points equally spaced over each one-hour period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the computation. Either an arithmetic or integrated average shall be used. The data output of the continuous emissions monitoring system may, at the owner's or operator's option, include a numerical format showing individual numerical readings and averages in addition to the required strip chart format with legible ink tracings and calibration information. All data output shall be clearly and properly identified by the operator. All system breakdowns, repairs, calibration checks, span adjustments and periods of excess emissions shall legibly appear on all data output.

b. Calculate and record on a daily basis the 12-hour average total reduced sulfur concentrations for two consecutive 12-hour periods of each operating day. Each 12-hour average shall be determined as the arithmetic mean of the appropriate 12 contiguous one-hour average total reduced sulfur concentrations provided by the continuous emissions monitoring system.

c. Calculate and record on a daily basis 12-hour average oxygen concentrations for two consecutive 12-hour periods of each operating day. These 12-hour averages shall correspond to the 12-hour average total reduced sulfur concentrations from sub-subparagraph 62-296.404(5)(b)2.b., F.A.C., and shall be determined as an arithmetic mean of the appropriate 12 contiguous one-hour average oxygen concentrations provided by each continuous emissions monitoring system.

d. Correct all 12-hour average total reduced sulfur (TRS) concentrations using the following equation:

$$C_{corr} = C_{meas}\,(21 - X)/(21 - Y)$$

where:

Ccorr = the TRS concentration corrected for oxygen.
Cmeas = the TRS concentration unconnected for oxygen.
X = the volumetric oxygen concentration in percentage that the measured TRS concentration is to be corrected to 8 percent for all recovery furnaces.
Y = the measured 12-hour average volumetric oxygen concentration.

e. The data shall be rounded to the same number of significant digits as the standard.

[Rules 62-296.404(5)(a) & (b), F.A.C.; 40 CFR 60, Appendix A; 40 CFR 60, Appendix B, Performance Specifications 5 and 6; and, 40 CFR 60, Appendix F]

A.38. Continuous Opacity Monitoring System (COMS). The owner or operator of each affected Kraft or soda recovery furnace equipped with an ESP must install, calibrate, maintain, and operate a COMS according to the provisions in 40 CFR 63.6(h) and 63.8 and 40 CFR 63.864(d)(1) through (4).

(1) [Reserved].
(2) [Reserved].
(3) As specified in 40 CFR 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.
(4) The COMS data must be reduced as specified in 40 CFR 63.8(g)(2).

[40 CFR 63.864(d)(3) & (4); and, 40 CFR 60, Appendix B, Performance Specification 1]

A.39. (e) Continuous Parameter Monitoring System (CPMS). For each CPMS required in this section, the owner or operator of each affected source or process unit must meet the requirements in 40 CFR 63.864(e)(1) through (14).

(1)-(9) [Reserved].
(10 – (12) Not applicable.
(13) The owner or operator of each affected source or process unit that uses an ESP, may monitor alternative control device operating parameters subject to prior written approval by the Administrator.
(14) Not applicable.

[40 CFR 63.864(e)(13)]

A.40. (j) Determination of Operating Ranges.

(1) During the initial performance test required in 40 CFR 63.865, the owner or operator of any affected source or process unit must establish operating ranges for the monitoring parameters in 40 CFR 63.864(e)(10) through (14), as appropriate; or
(2) The owner or operator may base operating ranges on values recorded during previous performance tests or conduct additional performance tests for the specific purpose of establishing operating ranges, provided that test data used to establish the operating ranges are or have been obtained using the test methods required in this subpart. The owner or operator of the affected source or process unit must certify that all control techniques and processes have not been modified subsequent to the testing upon which the data used to establish the operating parameter ranges were obtained.
(3) The owner or operator of an affected source or process unit may establish expanded or replacement operating ranges for the monitoring parameter values listed in 40 CFR 63.864(e)(10) through (14) and established in 40 CFR 63.864(j)(1) or (2) during subsequent performance tests using the test methods in 40 CFR 63.865.
(4) The owner or operator of the affected source or process unit must continuously monitor each parameter and determine the arithmetic average value of each parameter during each performance test. Multiple performance tests may be conducted to establish a range of parameter values.
(5) – (6). Not applicable.

[40 CFR 63.864(j)(1) thru (4)]

A.41. (k) On-going Compliance Provisions.

(1) Following the compliance date, owners or operators of all affected sources or process units are required to implement corrective action, as specified in the startup, shutdown, and malfunction plan prepared under 40 CFR 63.866(a) if the monitoring exceedances in 40 CFR 63.864(k)(1)(i) through (vi) occur:

(i) For an existing Kraft or soda recovery furnace equipped with an ESP, when the average of ten consecutive 6-minute averages result in a measurement greater than 20 percent opacity;
(ii) For an existing Kraft or soda recovery furnace, when any 3-hour average parameter value is outside the range of values established in 40 CFR 63.864(j);
(iii) Not applicable;
(iv) Not applicable;
(v) For an affected source or process unit equipped with an ESP and monitoring alternative operating parameters established in 40 CFR 63.864(e)(13), when any 3-hour average value is outside the range of parameter values established in paragraph (j) of this section; and
(vi) Not applicable.

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(2) Following the compliance date, owners or operators of all affected sources or process units are in violation of the standards of 40 CFR 63.862 if the monitoring exceedances in 40 CFR 63.864(k)(2)(i) through (vii) occur:

(i) For an existing Kraft or soda recovery furnace equipped with an ESP, when opacity is greater than 35 percent for 6 percent or more of the operating time within any quarterly period;

(ii) Not applicable;

(iii) Not applicable;

(iv) Not applicable;

(v) Not applicable;

(vi) For an affected source or process unit equipped with an ESP and monitoring alternative operating parameters established in 40 CFR 63.864(e)(13), when six or more 3-hour average values within any 6-month reporting period are outside the range of parameter values established in 40 CFR 63.864(j); and

(vii) Not applicable.

(3) For purposes of determining the number of non-opacity monitoring exceedances, no more than one exceedance will be attributed in any given 24-hour period.

[40 CFR 63.864(k)(1) thru (3)]

A.42. CMS/CEMS/COMS Certification and Initial Startup: Continuous monitoring systems are currently in place for emissions of TRS, SO_2, and opacity. Compliance with the TRS, SO_2, and opacity standards of this permit shall be begin upon the final issuance of this permit. The CO CEMS, NOx CEMS, and continuous flow monitor shall be installed and certified within at least 180 days of initial startup following the completion of the initial combustion air modifications. After these monitors are certified, the permittee is authorized to operate the recovery boiler for an additional shakedown period of 180 calendar days to gather operating and emissions data to develop good combustion practices. Thereafter, compliance shall be demonstrated with the CO and NOx standards by data collected from the required CEMS.

[Rules 62-4.070(3), 62-212.400(BACT) and 62-297.520, F.A.C.; 40 CFR 60, Appendices A, B and F]

A.43. CMS/CEMS Data Requirements: Each CEMS shall be installed, calibrated, maintained, and operated in the exhaust stack of the recovery boiler to measure and record the emissions of CO, NOx, SO_2, and TRS in a manner sufficient to demonstrate compliance with the emission limits of this permit. The CEMS shall express the results in units of ppmvd @ 8% O_2 and pounds per hour.

a. *Valid Hourly Averages:* Each CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour. Each 1-hour block average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel (black liquor) during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, there is insufficient data and the 1-hour block average is not valid. Hours during which the recovery boiler is not operating are not valid hours.

b. *12-hour Block Averages*: Each 12-hour block average shall be consistent with the methodology specified in Rule 62-296.404, F.A.C. and specific condition **A.37**.

c. *24-hour Rolling Averages*: Each 24-hour rolling average shall be recomputed after every valid hour as the arithmetic average of that hourly average and the preceding 23 valid hourly averages during which the recovery boiler operated (fired fuel).

d. *30-day Rolling Averages*: Each 30-day rolling average shall be the arithmetic average of all valid hourly averages collected for the current day and the previous 29 days during which the recovery boiler operated (fired fuel).

e. *12-Month Rolling Averages*: Each 12-month rolling average shall be the arithmetic average of all valid hourly averages collected during the current calendar month and the previous 11 calendar months.

f. *12-month Rolling Total*: Each 12-month rolling total shall be the total of all valid hourly mass emissions rates collected during the current calendar month and the previous 11 calendar months.

g. *Data Exclusion*: Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall monitor and record emissions during all operations including episodes of startups, shutdowns, and malfunctions.

h. *Availability*: Monitor availability for each CEMS used to demonstrate compliance shall be 95% or greater in any calendar quarter. Monitor availability shall be reported in the quarterly excess emissions report (see specific condition **A.48.**). In the event 95% availability is not achieved, the permittee shall provide the Department's Northeast District office with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Compliance Authority – Department's Northeast District office.

[Rules 62-4.130 and 62-4.070(3), F.A.C.]

Recordkeeping and Reporting Requirements.

A.44. In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Northeast District office in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

A.45. All recorded data shall be maintained on file by the owner or operator for a period of five (5) years.
[Rule 62-213.440, F.A.C.]

A.46. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department's Northeast District office on the results of each such test.
(b) The required test report shall be filed with the Department's Northeast District office as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department's Northeast District office to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.

15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

A.47. Quarterly Reporting Requirements: TRS. The owner or operator of a Kraft recovery furnace subject to the provisions of subsection 62-296.404(5), F.A.C. (Continuous Monitoring Requirements), shall submit a written total reduced sulfur emissions and surrogate parameter data report to the Department's Northeast District office postmarked by the 30th day following the end of each calendar quarter.

(a) The report shall include the following information:

1. The magnitude of excess emissions and the date and time of commencement and completion of each time period in which excess emissions occurred.
2. Specific identification of each period of excess emissions that occurs including startups, shutdowns, and malfunctions of the affected emissions unit. An explanation of the cause of each period of excess emissions, and any corrective action taken or preventive measures adopted. Excess emissions shall be all 12-hour periods for which the appropriate surrogate parameter data or total reduced sulfur continuous emissions monitoring data indicates that an applicable 12-hour average total reduced sulfur emission limiting standard for the emissions unit was exceeded.
3. The date and time identifying each period during which each continuous emissions monitoring system used to measure total reduced sulfur emissions or surrogate parameters was inoperative except for zero and span checks, and the nature of the system repairs or adjustments.
4. When no excess emissions have occurred or the continuous emissions monitoring system(s) have not been operative, or have been repaired or adjusted, such information shall be stated in the report.

(b) Any owner or operator subject to the provisions of subsections 62-296.404(5) and (6), F.A.C., shall maintain a complete file of any measurements, including continuous emissions monitoring system, monitoring device, and performance testing measurements; any continuous emissions monitoring system performance evaluations; any continuous emissions monitoring system or monitoring device calibration checks; any adjustments and maintenance performed on these systems or devices; and any other information required, recorded in a permanent legible form available for inspection. The file shall be retained for at least three years following the date of such measurements, maintenance, reports and records.

(c) Evaluation of Excess Emissions. The Department shall consider periods of excess emissions from any Kraft recovery furnace to be evidence of improper operation and maintenance of the monitored emissions unit provided that:

1. For Kraft recovery furnaces subject to the emissions limits of paragraph 62-296.404(3)(c), F.A.C., the excess emissions occur during more than one percent of the total number of possible contiguous 12-hour periods of excess emissions in a calendar quarter rounded to the nearest whole number (excluding only the actual 12-hour periods during which a startup, shutdown or malfunction of the Kraft recovery furnace occurred and only the actual 12-hour periods when the Kraft recovery furnace was not operating), and
4. The Department determines that the affected emissions unit, including air pollution control equipment, is not maintained and operated in a manner which is consistent with good air pollution control practices for minimizing emissions. Such determination shall be based on the failure of the owner or operator of the facility to provide records of maintenance and operation of the emissions unit and related equipment showing operation consistent with good air pollution control practices. Good air pollution control practices shall include:
    a. Operation of all equipment within permit limits for loading rates and other process parameters,
    b. An adequate preventive maintenance program based on manufacturer's recommendations or other accepted industry practices,
    c. Training of personnel in the operation and maintenance of equipment,

d. Visual and instrument inspections of equipment on a regular basis, and
e. Maintenance of an adequate on-site, or readily available, supply of equipment for routine repairs.

(d) The owner or operator of any Kraft pulp mill or tall oil plant shall notify the Department in writing within fourteen days of the date on which periods of excess emissions exceed the percentages allowed by subparagraphs 62-296.404(6)(c)1. through 3., F.A.C.
[Rule 62-296.404(6), F.A.C.]

A.48. Quarterly Reporting Reports: Within 30 days following each calendar quarter, the permittee shall submit a written report to the Department's Northeast District summarizing the following: monitor availability; summary of emissions for the calendar quarter (CO, NOx, SO_2, TRS, and opacity); and excess emissions.
[Rule 62-4.070(3), F.A.C.]

A.49. Recordkeeping Requirements.
(a) Startup, Shutdown, and Malfunction Plan. The owner or operator must develop and implement a written plan as described in 40 CFR 63.6(e)(3) that contains specific procedures to be followed for operating the source and maintaining the source during periods of startup, shutdown, and malfunction, and a program of corrective action for malfunctioning process and control systems used to comply with the standards. In addition to the information required in 40 CFR 63.6(e), the plan must include the requirements in paragraphs 40 CFR 63.866(a)(1) and (2).

(1) Procedures for responding to any process parameter level that is inconsistent with the level(s) established under 40 CFR 63.864(j), including the procedures in paragraphs 40 CFR 63.866(a)(1)(i) and (ii):

(i) Procedures to determine and record the cause of an operating parameter exceedence and the time the exceedance began and ended; and

(ii) Corrective actions to be taken in the event of an operating parameter exceedance, including procedures for recording the actions taken to correct the exceedance.

(2) The startup, shutdown, and malfunction plan also must include the schedules listed in paragraphs 40 CFR 63.866(a)(2)(i) and (ii):

(i) A maintenance schedule for each control technique that is consistent with, but not limited to, the manufacturer's instructions and recommendations for routine and long-term maintenance; and

(ii) An inspection schedule for each continuous monitoring system required under 40 CFR 63.864 to ensure, at least once in each 24-hour period, that each continuous monitoring system is properly functioning.

(b) The owner or operator of an affected source or process unit must maintain records of any occurrence when corrective action is required under 40 CFR 63.864(k)(1), and when a violation is noted under 40 CFR 63.864(k)(2).

(c) In addition to the general records required by 40 CFR 63.10(b)(2), the owner or operator must maintain records of the information in paragraphs 40 CFR 63.866(c)(1) through (7):

(1) Not applicable.

(2) Records of CaO production rates in units of Mg/d or ton/d for all lime kilns;

(3) Records of parameter monitoring data required under 40 CFR 63.864, including any period when the operating parameter levels were inconsistent with the levels established during the initial performance test, with a brief explanation of the cause of the deviation, the time the deviation occurred, the time corrective action was initiated and completed, and the corrective action taken;

(4) Records and documentation of supporting calculations for compliance determinations made under 40 CFR 63.865(a) through (d);

(5) Records of monitoring parameter ranges established for each affected source or process unit;

(6) Not applicable.

(7) Not applicable.

[40 CFR 63.866(a), (b) & (c)]

A.50. Reporting Requirements.
(a) Notifications.

(1) The owner or operator of any affected source or process unit must submit the applicable notifications from Subpart A of 40 CFR 63, as specified in Table 1 of 40 CFR 63, Subpart MM.

(2) Not applicable.

(3) Not applicable.

(b) Not applicable.

(c) Excess Emissions Report. The owner or operator must report quarterly if measured parameters meet any of the conditions specified in 40 CFR 63.864(k)(1) or (2). This report must contain the information specified in 40 CFR 63.10(c) as well as the number and duration of occurrences when the source met or exceeded the conditions in 40 CFR 63.864(k)(1), and the number and duration of occurrences when the source met or exceeded the conditions in 40 CFR 63.864(k)(2). Reporting excess emissions below the violation thresholds of 40 CFR 63.864(k) does not constitute a violation of the applicable standard.

(1) When no exceedances of parameters have occurred, the owner or operator must submit a semiannual report stating that no excess emissions occurred during the reporting period.

(2) The owner or operator of an affected source or process unit subject to the requirements of Subpart MM and Subpart S of 40 CFR Part 63 may combine excess emissions and/or summary reports for the mill.

[40 CFR 63.867(a) & (c)]

B. New Crystallizer and Associated Storage/Flash Tank.

B.1. The permittee is authorized to install a new Crystallizer and associated Storage/Flash tank (June 2006 to May 2008) as a modification to the existing multiple effect evaporators (MEEs) and two associated concentrators (Emissions Unit 032). The purpose is to increase the temperature of and remove ("flash off") moisture from the black liquor received from the existing MEEs and two associated concentrators in order to increase the black liquor solids from 65% to approximately 75%, which will then be fired in the existing No. 4 Recovery Boiler. The emissions from the Crystallizer and associated storage/flash tank shall be routed back to the MEEs and collected as part of the existing non-condensable gas (NCG) collection system. The preliminary schedule is for startup of the new crystallizer/evaporator by May of 2008.
[Rules 62-4.070(3) and 62-210.300(1), F.A.C.]

C. No. 4 Lime Kiln.

C.1. Methods of Operation: No. 6 Fuel Oil. The No. 4 Lime Kiln (Emissions Unit 017) is permitted to fire No. 6 fuel oil with a sulfur content that shall not exceed 2.10%, by weight, and it may include on-spec used oil. The permittee is authorized to fire any fuel oil remaining in the tank, but shall only add fuel oil meeting the new fuel sulfur specification after issuance of this permit.
[Rules 62-4.070(3) and 62-212.400(12)(Source Obligation), F.A.C.]

D. No. 4 Combination Boiler.

D.1. Methods of Operation: No. 6 Fuel Oil.
a. The No. 4 Combination Boiler (Emission Unit 016) is permitted to fire No. 6 fuel oil with a sulfur content that shall not exceed 2.10%, by weight, and it may include on-spec used oil. The permittee is authorized to fire any fuel oil remaining in the tank, but shall only add fuel oil meeting the new fuel sulfur specification after issuance of this permit.
b. The maximum No. 6 fuel oil that may be fired is 5,030,000 gallons during any consecutive 12-months, rolling total.
[Rules 62-4.070(3) and 62-212.400(12)(Source Obligation), F.A.C.]

E. No. 4 Power Boiler.

E.1. The No. 4 Power Boiler (Emission Unit 014) shall remain permanently shut down.
{Permitting Note: The existing No. 4 Power Boiler shutdown in September 2003. The actual emissions from this unit were used in the PSD netting analysis as a contemporaneous decrease. The status of this unit will be designated as "Inactive" in the Division's Air Resource Management System (ARMS) database.}
[Application No. 1070005-035-AC; Rules 62-4.070(3), 62-210.200(Definitions: Actual Emissions) and 62-212.400(PSD NSR), F.A.C.]

CONTENTS

CITATION FORMATS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

COMMON STATE REQUIREMENTS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(203), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

GENERAL COMPLIANCE TESTING REQUIREMENTS

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]
11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new

test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]

12. <u>Calculation of Emission Rate</u>: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

13. <u>Applicable Test Procedures [Rule 62-297.310(4), F.A.C.]</u>

    a. *Required Sampling Time.*

        (1) Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

        (2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

            (a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

            (b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

            (c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

    b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

    c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

    d. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.

    e. *Allowed Modification to EPA Method 5.* When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

14. <u>Determination of Process Variables [Rule 62-297.310(5), F.A.C.]</u>

    a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

    b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

15. <u>Sampling Facilities</u>: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also

comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E. [Rule 62-297.310(6), F.A.C.]

a. *Permanent Test Facilities.* The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

b. *Temporary Test Facilities.* The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

c. *Sampling Ports.*

(1) All sampling ports shall have a minimum inside diameter of 3 inches.

(2) The ports shall be capable of being sealed when not in use.

(3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

(4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

(5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

d. *Work Platforms.*

(1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

(2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

(3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

(4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform.*

(1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

(2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

f. *Electrical Power.*

(1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

(2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support.*

(1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

(a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

(b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

(c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

(2) A complete monorail or dual rail arrangement may be substituted for the eyebolt and bracket.

(3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

16. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required. [Rule 62-297.310(7), F.A.C.]

a. *General Compliance Testing.*

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

(a) Did not operate; or

(b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,

4. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

(a) Visible emissions, if there is an applicable standard;

(b) Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

(c) c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned

for more than 200 hours other than during startup.

7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.
8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

b. *Special Compliance Tests.* When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

c. *Waiver of Compliance Test Requirements.* If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of paragraph 62-297.310(7)(b), F.A.C., shall apply.

RECORDS AND REPORTS

17. <u>Test Reports [Rule 62-297.310(8), F.A.C.]</u>

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

b. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

c. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information.

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.

8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

RECORDS AND REPORTS

18. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]
19. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

SUMMARY OF FINAL BACT DETERMINATIONS

Project Description

The project includes the following:

- May 2006: Modify combustion air system; replace 25% of wall tubes in recovery boiler; and start construction of new crystallizer and upgrades to concentrator/evaporator;
- April/May of 2007: Replace tubes in superheater, economizer, and 25% of wall in recovery boiler; and
- May 2008: Startup of new crystallizer/evaporator.

The project will not increase the maximum capacity of the recovery boiler or the pulp mill (118 tons/hour ADUP and 1850 tons/day ADUP, monthly average).

Air Pollution Control Equipment and Techniques

The following control equipment and techniques represent the Best Available Control Technology (BACT) determined for the project to modify the No. 4 Recovery Boiler. PM/PM_{10} emissions will be minimized by the continued use of the existing 2-chamber, 6 field/chamber electrostatic precipitator (ESP) with automatic voltage control. NO_x emissions will be minimized by modifying the existing combustion air system to add a 4th level of combustion air (quaternary air) and good combustion practices. CO and VOC emissions will be minimized by good combustion practices for the existing furnace design. Sulfuric acid mist (SAM) will be minimized by proper operation of the recovery process.

Final BACT Determinations

In accordance with Rule 62-212.400(6), F.A.C., the Department establishes the following standards that represent the Best Available Control Technology (BACT) for the following pollutants: carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and volatile organic compounds (VOC).

EU-018. No. 4 Recovery Boiler – Summary of Final BACT Determinations

Pollutant	Draft BACT Standards	Control Technology	Monitoring
PM/PM_{10}	0.030 grains/dscf @ 8% O_2	Electrostatic Precipitator (ESP)	Stack Test at Capacity
NO_x	80 ppmvd @ 8% O_2, 30-day rolling avg. (Excludes startup, shutdown, malfunction)	4-Level Overfire Air System	CEMS
CO	800 ppmvd @ 8% O_2, 3-hour avg.	Boiler Design and GCPs	Stack Test at Capacity
	400 ppmvd @ 8% O_2, 24-hour avg.	Boiler Design and GCPs	Stack Test at Capacity
	400 ppmvd @ 8% O_2, 30-day rolling avg. (Excludes startup, shutdown, malfunction)	Boiler Design and GCPs	CEMS
SAM	0.81 ppmvd @ 8% O_2	Process	Stack Test at Capacity
VOC	0.20 lbs/ton BLS	Boiler Design and GCPs	Stack Test at Capacity (Surrogate: CO CEMS)

The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit for the original project.