Georgia-Pacific

Palatka Pulp and Paper Operations
Consumer Products Division

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

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

August 22, 2007

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

RECEIVED
AUG 24 2007
BUREAU OF AIR REGULATION

Re: Project No. 1070005-038-AC/PSD-FL-380
EU no. 014 – No. 4 Power Boiler
Notice of Permanent Shutdown

Dear Mr. Koerner:

In accordance with condition 3.A.1 of permit PSD-FL-380, this letter provides written notice of the permanent shutdown of the No. 4 Power Boiler (EU – 14).

If you have any questions regarding this correspondence, please contact Ron Reynolds at 386-329-0967.

I, the undersigned, am the responsible official of the source for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and the data contained in this document are true, accurate, and complete.

Sincerely,

Keith Wahoske

Keith W. Wahoske, Vice-President
Palatka Operations

cc: W. Galler, T. Champion, T. Wyles, S. Matchett, R. Reynolds, M. Curtis - GP

Georgia-Pacific

Palatka Pulp and Paper Operations
Consumer Products Division

P.O. Box 919
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May 25, 2007

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

Re: Project No. 1070005-038-AC PSD-FL-380
Modification of the No. 4 Recovery Boiler, No. 4 Lime Kiln and No. 4 Combination Boiler
Response to Request for Additional Information No. 3

Dear Mr. Koerner:

We are in receipt of your request for additional information, dated December 15, 2006, regarding our PSD permit application project to make modifications to the No. 4 Recovery Boiler, No. 4 Lime Kiln, and No. 4 Combination Boiler.

This response addresses question number 5 of the Department's December 15, 2006 request for additional information. A response to questions 2, 6 (second response) and 7 was submitted to FDEP on January 31, 2007. A response to questions 1, 3, 4 and 6 (second response) was submitted to FDEP on March 9, 2007.

Additionally, this response seeks relief from the short-term Recovery Boiler SO_2 limits while burning fuel oil, a concern voiced by GP in a conference call with FDEP on May 4, 2007.

For ease of following GP's responses, we have repeated the FDEP's questions prior to the answers.

No. 4 Combination Boiler

5. **Based on your submittals, the Department believes several of the identified NO_x control options are likely cost effective including selective non-catalytic reduction (SNCR), the Ecotube system with urea injection, and flue gas recirculation (FGR). These controls have been successfully installed on similar units. The Department's review focused on the SNCR system, which has been successfully installed and operated on several units in Florida including RDF boilers, wood-fired boilers, and bagasse-fired boilers. However, both the Ecotube with urea injection and flue gas recirculation (FGR) may also be able to provide similar reductions with comparable**

costs.

SNCR*:* The preliminary SNCR design was based on the co-firing of residual oil with a maximum fuel sulfur content of 2.5% by weight. When the fuel sulfur content is above approximately 1.5% by weight, the vendor indicates that a critical design constraint is to substantially limit the ammonia slip to prevent the formation of ammonium bisulfates, which can foul boiler heat transfer surfaces. With regard to the SNCR design, this will likely result in more injectors, additional injector levels, restricted urea injection rates, and reduced control efficiencies. Although the vendor indicated a reduction of 35% in the bid for the primary fuel scenario (bark/oil), the cost effectiveness estimate was based upon only 30% reduction. Existing biomass-fired boilers are achieving control efficiencies of up to 50% reduction. Will the No. 4 Combination Boiler fire bark/wood alone without other fuels? Please provide a vendor quote on equipment and installation costs for an SNCR system firing bark/wood alone and firing bark/wood with oil having a maximum fuel sulfur content of less than 1.0%. Please include the input criteria for the hid, the expected control efficiencies, and the urea injection rate.

***Ecotube Plus Urea Injection:* The estimated cost effectiveness for this system is actually lower than that estimated for SNCR. In addition, the vendor indicates co-benefits for reducing CO emissions, which is also subject to a BACT determination for this project. Please provide the vendor quote used for the Ecotube system with/without urea injection including the input criteria, estimated installation costs, control efficiencies, and urea injection rate.**

***FGR:* When combined with air staging, flue gas recirculation (FGR) has achieved control efficiencies approaching 50% reduction for similar units depending on initial uncontrolled NO_x emissions rates. Please provide the vendor quote for the FGR system including the input criteria, estimated installation costs, and control efficiency.**

Provide a revised cost effectiveness analysis ($/ton NO_x removed) for each of these controls options and identify the most cost effective option.

The project identifies the following physical modifications to the No. 4 Combination Boiler: modified conveyors; new air swept bark distributors; a new overfire air (OFA) system: new low-NO_x burners (LNB): and possibly new baffles to more evenly distribute the underfire air. The primary purpose for these modifications is to improve combustion of the bark/wood fuel and the overall burning rate of this fuel to reduce oil firing. Such changes will affect pollutant emissions, which could affect the design of the control systems. For the selected NO_x control option, provide a schedule and comments regarding the following: commencement through completion of the boiler modifications, boiler shakedown; performance and emissions testing after completing the boiler modifications; development and final design of the NO_x control system; commencement through completion of installing the NO_x control system; initial startup and shakedown alter completing the NO_x control system; equipment shakedown and tuning; initial compliance testing: and monitor certification.

Answer: On Friday, May 4, 2007, a telephone conference call was held between Bruce Mitchell and Jeff Koerner of FDEP and Mike Curtis, Ron Reynolds, Wayne Galler, and Mark Aguilar of GP to discuss NO_x control options for the No. 4 Combination Boiler. As discussed during the telephone conversation, since the time that the PSD permit application for the No. 4 Combination Boiler was submitted by Golder & Associates (for GP) to FDEP in July 2006, GP has obtained new and more accurate cost data to install an SNCR system for the reduction of NO_x emissions from the No. 4 Combination Boiler. The new cost data was prepared by Jacobs Engineering of Greenville, South Carolina in November 2006, and was prepared as part of their contract work for GP to estimate control system costs for the BART requirements. Jacob's cost estimate for installation of an SNCR system for the No. 4 Combination Boiler was based on a +/- 30% accuracy, but Jacob's cost estimate contains much more detail than the one prepared by Golder & Associates for the July 2006 PSD permit application. A copy of Jacob's cost estimate is attached to this submittal as Attachment 1. The basis for Jacob's cost estimate is attached to this submittal as Attachment 2.

Utilizing Jacob's cost data for installation of an SNCR system and Golder's cost effectiveness calculation spreadsheet (Table 5-10) contained in the July 2006 PSD permit application, the cost effectiveness for use of an SNCR system supplied by Fuel-Tech, Inc. would be \$7,848/ton NO_x removed. This is much higher than the cost effectiveness value of \$5,419/ton NO_x removed reported in Table 5-10 of Golder's July 2006 PSD permit application. The baseline emissions used in Table 5-10 was 356.1 tons of NO_x, which is based on a "post-BART" NO_x emission rate of 0.22 lbs NO_x/MM Btu heat input. Previous conversations between Mark Aguilar of GP and FDEP resulted in an agreement that the baseline period for this analysis may consider the expected controls that would be in place for the No. 4 Combination Boiler. FDEP reaffirmed this agreement during the May 4th telephone discussion with GP. The basis for the 0.22 lb NO_x/MM Btu heat input value comes from a performance guarantee provided to GP by Jansen Combustion and Boiler Technologies, Inc. for the No. 4 Combination Boiler (dated January 26, 2007, Revision 2-see Section 9.3.2 of Attachment 3). The emissions guarantee is based on the No. 4 Combination Boiler firing a combination of bark and natural gas over an eight-hour test period. The 0.22 lb/MM Btu value assumes the use of low-NO_x gas-fired burners and an overfire air system.

GP does not believe a value of almost \$8,000 per ton of NO_x removed for an SNCR system is a cost effective approach for reducing NO_x emissions from the No. 4 Combination Boiler.

GP has not provided a cost effectiveness analysis for the use of an SNCR system for the No. 4 Combination Boiler burning a combination of bark and No. 6 Fuel Oil since it is not the Mill's intent to burn No. 6 fuel oil in the boiler under the future operating scenario. It is the Mill's intent to burn a combination of bark and natural gas in the No. 4 Combination Boiler under the future operating scenario.

Regarding the FDEP's question about whether or not the No. 4 Combination Boiler can burn 100% bark, the answer is rarely. Fuel oil is expensive and we certainly want to burn as much wood fuel as we can in the Combination Boiler. However, we generally must also burn fuel oil to meet the steam/energy needs of the mill. Even when fuel oil is not necessarily needed to supplement the BTUs from bark/wood fuel, some minimal amount of fuel oil is burned as a safety measure to protect against tripping the boiler, and perhaps shutting down the mill, in case of a malfunction in the wood fuel feed system.

Regarding the Ecotube technology offered by Synterprise LLC, GP does not believe the NO_x emission reductions obtained with biomass boilers operated by certain Utilities in the northeast

United States are attainable for the No. 4 Combination Boiler. The Ecotube system has primarily been installed on waste to energy boilers and on larger biomass fired boilers which typically had operated in an excess oxygen range of 6% to 10%. NO_x formation is highly dependant on proper fuel-air mixing as well as time and temperature of the reaction. The amount of excess oxygen in the furnace affects flame temperatures and amount of elemental nitrogen (N_2) present for NO_x formation as the higher the percent excess oxygen, the higher the NO_x will be in general, due to higher flame temperatures and additional N_2 present in the air for conversion to NO_x. Inversely, as excess oxygen is reduced to levels closer to sub-stoichiometric rates, flame temperatures are reduced, therefore, the amount of N_2 available is reduced, and a slight reducing atmosphere is created, thereby lowering NO_x emissions.

In reviewing the operations of the No. 4 Combination Boiler, which normally has an excess oxygen content of 4% on a dry basis, the estimated reduction efficiency for NO_x would be in the 15% range; a review of Ecotube's proposal to GP (E-mail from Bill Buckley of Synterprise to Rob Orender of GP, dated December 22, 2005-see Attachment 4, page 2, second to last paragraph), Synterprise stated that they would expect a 20% reduction in NO_x emissions. This unit also has 6 burners which utilize air to keep the burners cool while they are out-of-service. This excess air is not effectively utilized in the combustion process and thereby can contribute to higher than expected NO_x emissions.

Synterprise's available references for NO_x emissions before and after Ecotube technology installations consist of two sites in Europe with NO_x reductions and oxygen levels which are listed below:

	% Oxygen Before	% Oxygen After	NO_x (ppm) Before	NO_x (ppm) After	% Reduction
Karlskoga	6.0	4.0	130	60	53.8
Kristineheds	6.0	3.0	430	130	69.8

The Karlskoga site used the Ecotube system and limestone for NO_x emissions controls and the Kristineheds site utilized Ecotube as well as a urea-based de-NO_x system.

In order to obtain a guaranteed NO_x reduction value for the No. 4 Combination Boiler from Synterprise, GP would need to pay an estimated $35,000 fee for a modeling study to be performed by Synterprise. Based on what we know about the Ecotube technology and the operation of the No. 4 Combination Boiler, GP does not think it would be wise to spend the $35,000 modeling fee with an expectation of only a 15-20% NO_x reduction. We believe that the performance guarantee from Jansen Combustion and Boiler Technologies, Inc. of 0.22 lb/MM Btu is approximately equivalent to a 15-20% overall NO_x reduction. The baseline NO_x emissions from the No. 4 Combination Boiler prepared by Golder & Associates in Table 5-10 of the PSD permit application was 0.27 lb/MM Btu for fuel oil and 0.24 lb/MM Btu for bark. The 0.27 lb/MM Btu value for fuel oil combustion incorporated a 15% reduction with the use of low-NO_x burners, so the uncontrolled NO_x emission rate was equal to 0.31 lb/MM Btu. The actual NO_x reduction achieved by incorporating the modifications required by Jansen to meet their performance guarantee for the No. 4 Combination Boiler will depend upon the fuel mix of bark and natural gas. However, just by switching fuel from No. 6 fuel oil to natural gas, the overall average emission factor changes by a minimum of 12% (by dropping from an average of 0.25 lbs NO_x/MM Btu to 0.22 lbs/MM Btu). GP expects the actual NO_x emission rate to be lower than

0.22 lbs/MM Btu when burning gas and bark, therefore, the actual NO_x reduction achieved by the No. 4 Combination Boiler should be greater than 12%.

Regarding the final selection of the NO_x control system for the No. 4 Combination Boiler and the control system installation schedule, GP offers the following information:

> GP proposes to install to install a new overfire air system as the selected NO_x control option for the initial phase of the modification to begin in November 2006. A second phase will proceed with the installation of low-NO_x burners when the additional natural gas supply is made available by the local utility, which we are told could take up to two years. Shakedown of the boiler is anticipated to require up to 60 days after which initial compliance stack testing will be completed within the usual 60 days of achieving permitted capacity, but not later than 180 days after startup.

No. 4 Recovery Boiler

GP seeks relief from the short-term SO_2 limits while burning fuel oil, a concern that was also discussed in the conference call with FDEP on May 4, 2007.

Comment: GP has no objection to the Recovery Boiler SO_2 limitation of 153.9 tons per year (12-month rolling total) based on CEMS data. However, GP requests the following language be added in order to provide relief during periods of fuel oil firing from the current short term SO_2 limits of 75 ppm and 109.9 lb/hr:

> *"During periods when fuel oil is burned, such as start ups, shutdowns, malfunctions, and other temporary upset or maintenance situations, SO_2 emissions shall be limited only by the sulfur content (2.35%) of the fuel oil and a maximum fuel oil firing rate of 84 GPM."*

Discussion: The current SO_2 limit, as represented in the Title V permit 1070005-031-AV, condition E.7., states that "Sulfur Dioxide Emissions shall not exceed 75 ppmvd at 8% O_2; 109.9 lb/hr, and 481.4 TPY based on an average of three test runs"...etc. The proposed draft permit PSD-FL-380 lowers the annual SO_2 limit to 153.9 TPY based on a 12-month rolling CEMS total. GP has concerns regarding the short term limits of 75 ppm and 109.9 lbs/hr during startup, shutdown, malfunction, and other temporary situations when fuel oil must be burned at much higher than normal rates. The Title V permit language clearly states that the limits apply during stack testing conditions, which would typically involve near-maximum black liquor firing rates and very low or no fuel oil. However, if the old short-term limits are to be incorporated into the Title V with the proposed CEMS monitoring scheme then compliance will be impossible during the identified situations requiring high fuel oil use.

During periods of startup, shutdown, malfunction, maintenance on the black liquor system, and process upsets, fuel oil must be burned for periods lasting from several hours to as much as 24 hours at much higher rates than during normal operation. During startup, the boiler must be fired on fuel oil until the furnace is hot enough to sustain combustion of black liquor. Then, the fuel oil guns gradually reduce the amount of fuel oil that is fired while the black liquor guns are added one-by-one until the boiler is stabilized on 100% black liquor. During shutdown periods, fuel oil is burned to burn the smelt bed out of the bottom of the Recovery. Maintenance work on the black liquor feed system may also necessitate burning only fuel oil in order to maintain steam.

Fuel oil may also be burned at higher than normal rates during process upsets or malfunction situations to maintain steam and stabilize the boiler until normal operation can be achieved. The suggested startup/shutdown/malfunction fuel oil firing rate of 84 gpm, and the resulting SO_2 emissions, was accounted for in short-term air modeling that was performed and submitted to the FL DEP in 2006, indicating compliance with the short-term SO_2 NAAQS standards. Therefore, GP proposes that incorporation of the suggested permit language will be sufficiently protective of air quality and allow needed operational flexibility while maintaining compliance.

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

I, the undersigned, am the responsible official of the source for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and the data contained in this document are true, accurate, and complete.

Sincerely,

Keith Wahoske

Keith W. Wahoske, Vice-President
Palatka Operations

cc: W. Galler, T. Champion, T. Wyles, S. Matchett, R. Reynolds, M. Curtis - GP

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

Cost Items	Cost Factors[a]	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
SNCR Basic Process	Vendor quote[b]	$875,000
NOxOUT Storage Tank	10,000 gallon; included in vendor quote	--
Emissions Monitoring	15% of equipment cost	$131,250
Foundation and Structure Support	8% of equipment cost	$70,000
Freight	Vendor quote[b]	$12,000
Taxes	Florida sales tax, 6%	$52,500
Total PEC:		$1,140,750
Direct SNCR Installation	GP vendor quotes for similar boiler: 70% of basic	$753,375
Total DCC:		$1,894,125
INDIRECT CAPITAL COSTS (ICC):		
Air and Water Piping	Based on GP Engineering Estimate	$50,000
Electrical and Controls	Based on GP Engineering Estimate	$50,000
Performance testing	Based on GP Engineering Estimate	$100,000
Engineering and Supervision	Portion performed by GP (5% of Total DCC)	$94,706
Modeling	Included in vendor quote	--
Start-up and Optimization Service	Included in vendor quote	--
Temperature monitoring	Based on Engineering Estimate	$45,000
Operation and Maintenance Manuals (5)	Included in vendor quote	--
General Facilities	5% of DCC	$94,706
Engineering and home office fees	10% of DCC	$189,413
Process Contingency	5% of DCC	$94,706
Total ICC:		$718,531
PROJECT CONTINGENCY (RETROFIT):	30% of (DCC + ICC)	$783,797
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	$4,267,000
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	2 hours/week, $16/hr, 52 weeks/yr	$1,664
Supervisor	15% of operator cost	$250
(2) Maintenance	1.5% of TCI	$64,005
(3) NOx-OUT solution cost	18 gal/hr, $1.45/gal[c], 80% C.F.	$182,909
(4) Electricity	66 kW, $0.08/kW-hr, 80% C.F.	$37,002
(5) Water	520 gph; $0.00064/ga, 80% C.F.	$2,332
(6) Fuel- bark/wood (loss in efficiency)	1 MM Btu/yr, $3/MM Btu, 80% C.F.	$21,024
Total DOC:		$309,186
INDIRECT OPERATING COSTS (IOC):		
Overhead	30% of oper. labor & maintenance	$19,776
Property Taxes	0.5% of total capital investment	$21,335
Insurance	1% of total capital investment	$42,670
Administration	1% of total capital investment	$42,670
Total IOC:		$126,451
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.09439 times TCI (20 yrs @ 7%)	$402,762
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	$838,399
BASELINE NO_x EMISSIONS (TPY) :	Bark-avg of 2004/2005 = 2,563,380 MM Btu	356.1 [d]
	Oil-avg of 2004/2005 = 673,878 MM Btu	
	0.22 lb/MMBtu for natural gas and for bark	
MAXIMUM NO_x EMISSIONS w/SNCR (TPY) :	0.22 lb/MM for bark (4,042,127 MM Btu/yr)	444.6
	0.22 lb/MM Btu for natural gas (750,000 MM Btu)	82.5
	Total NO_x future	527.1
REDUCTION IN NO_x EMISSONS (TPY):	30% reduction from baseline[e]	106.8
COST EFFECTIVENESS:	$ per ton of NO_x Removed	$7,848

Footnotes:

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

[b] NO_x OUT SNCR NO_x Reduction System Proposal, Fuel Tech, Inc., January 5, 2006.

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

[d] Based on bark average usage of 284,820 tons/yr @ 4,500 Btu/lb; fuel oil average usage of 4,492,520 gal/yr @ 150,000 Btu/gal
Bark = 2,563,380 MM Btu/yr and oil = 673,878 MM Btu/yr for a total of 3,237,258 MM Btu/yr
NO_x = baseline of 0.22 lb/MM Btu (after BART controls in place) or 356.1 tons/yr

[e] 30% NO_x reduction was used as this was an average of the different fuel firing scenarios:
35% NO_x reduction for bark/wood and 25% on fuel oil-bottom of Page 5-14 in July 2006 PSD application

Note: Natural gas will replace the Btu content of oil burned in the No. 4 Combination Boiler in the future

ATTACHMENT I

TOTAL COST SUMMARY - JE PRIME CODE

JE

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)

ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

G:\ESTIMAT\GEORPAC\FLORIDA\PALATKA\16DC9000 - BART BOILER PROGRAM\PALATKA COMBINATION BOILER NO. 4 - SNCR\[16DC9000 - TCS - PALATKA COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR_R1.xls]PRIME

PRIME CODE	DESCRIPTION	W-H	QTY	UNIT	LABOR	EQUIPMENT	MATERIAL	SUBCONTRACT	TOTAL COST
	DIRECT COSTS								
50	MAJOR EQUIPMENT	1,699	0	0	$92,082	$1,022,900	$15,344	$0	$1,130,305
51	DEMOLITION	469	0	0	$25,432	$0	$0	$0	$25,432
52	SITE EARTHMOVING	0	0	0	$0	$0	$0	$0	$0
53	SITE IMPROVEMENTS	0	0	0	$0	$0	$0	$56,515	$56,515
54	PILING, CAISSONS	0	791	LF	$0	$0	$0	$79,121	$79,121
55	BUILDINGS	0	1	LOT	$0	$0	$0	$80,000	$80,000
56	CONCRETE	369	31	CY	$16,955	$0	$16,955	$0	$33,909
57	MASONRY, REFRACTORY	0	0	0	$0	$0	$0	$0	$0
58	STRUCTURAL STEEL	1,353	39	TN	$67,818	$0	$135,637	$0	$203,455
59	ROOFING AND SIDING	0	0	0	$0	$0	$0	$0	$0
60	FIRE PROOFING	0	0	0	$0	$0	$0	$0	$0
61	PROCESS DUCTWORK (NON-BUILDING)	0	0	0	$0	$0	$0	$0	$0
62	PIPING	1,669	556	LF	$90,424	$0	$101,727	$0	$192,152
63	INSULATION - PIPE, EQUIPMENT & DUCTWORK	1,108	1	LOT	$50,884	$0	$0	$50,884	$101,727
64	INSTRUMENTATION	111	6	EA	$5,652	$11,303	$11,303	$0	$28,258
65	ELECTRICAL	550	2,200	LF	$27,941	$93,615	$45,212	$0	$166,768
66	PAINTING, PROTECTIVE COATINGS	123	0	0	$5,652	$0	$5,652	$0	$11,303
67	FURNITURE, LAB & SHOP EQUIPMENT	0	0	0	$0	$0	$0	$0	$0
	TOTAL DIRECT COSTS	7,452			$382,799	$1,127,818	$331,829	$266,500	$2,108,946
	$ / WH	$51.37							
	CONSTRUCTION INDIRECT COSTS								
75	CONSTRUCTION SUPPORT LABOR	1,490			$60,409	$0	$0	$0	$60,409
76	TEMPORARY CONSTRUCTION FACILITIES (IN WAGE RATES)				$0	$0	$0	$0	$0
78	PREMIUM TIME				$23,354	$0	$0	$0	$23,354
79	CRAFT FRINGE BENEFITS (IN WAGE RATES)				$0	$0	$0	$0	$0
	CRAFT PER DIEM ($7 PER HOUR ON 100 % OF THE HOURS)				$0	$0	$0	$62,601	$62,601
80	PAYROLL TAXES & INSURANCE (IN WAGE RATES)				$0	$0	$0	$0	$0
83	SMALL TOOLS (IN WAGE RATES)				$0	$0	$0	$0	$0
84	CONSUMABLE SUPPLIES (IN WAGE RATES)				$0	$0	$0	$0	$0
85	CONSTRUCTION EQUIPMENT (IN WAGE RATES)				$0	$0	$0	$0	$0
87	FIELD STAFF (IN WAGE RATES)				$0	$0	$0	$0	$0
81	NON-PAYROLL TAX, INSURANCE & PERMITS				$0	$73,308	$21,569	$8,661	$103,538
93	CONSTRUCTION HOME OFFICE COST (INC. WITH CONTRACTOR'S CONSTRUCTION FEE)				$0	$0	$0	$0	$0
71	CRAFT START-UP ASSISTANCE	450			$33,300	$0	$0	$0	$33,300
99	CONTRACTOR'S CONSTRUCTION HOME OFFICE & FEE		10.0%	TCC LESS EQ.	$45,597	$0	$53,010	$33,776	$132,382
	TOTAL CONSTRUCTION INDIRECT COSTS	1,940			$162,659	$73,308	$74,579	$105,039	$415,584
	TOTAL CONSTRUCTION COSTS (TCC)	9,393			$545,458	$1,201,126	$406,407	$371,539	$2,524,531
	$ / WH	$73.97							
	PROJECT INDIRECT COSTS								
88	CONSTRUCTION MANAGEMENT		4.5%	TIC	$0	$0	$0	$192,798	$192,798
90	ENGINEERING PROFESSIONAL SERVICES		10.0%	TIC	$0	$0	$0	$424,953	$424,953
90	STUDY COST				$0	$0	$0	$50,000	$50,000
96	OUTSIDE CONSULTANT SERVICES				$0	$0	$0	$100,000	$100,000
91	OWNER'S COST		3.0%	TIC	$0	$0	$0	$128,928	$128,928
70	SPARE PARTS				$0	$56,391	$0	$0	$56,391
71	NON-CRAFT START-UP ASSISTANCE				$49,950	$0	$0	$69,200	$119,150
98	ALLOWANCE FOR UNFORESEEN		8.3%	TIC	$59,541	$125,752	$40,641	$128,742	$354,675
96	ESCALATION		5.0%	TIC	$0	$125,752	$56,182	$33,483	$215,418
	AIR INFILTRATION ALLOWANCE				$0	$0	$0	$100,000	$100,000
	ROUND OFF				$52	($21)	($231)	$357	$157
	TOTAL PROJECT COSTS	9,393			$655,000	$1,509,000	$503,000	$1,600,000	$4,267,000
	$ / WH	$73.97							

DETAIL DIRECT COST

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)
G:\ESTIMAT\GEORPAC\FLORIDA\PALATKA\16DC9000 - BART BOILER PROGRAM\PALATKA COMBINATION BOILER NO. 4 - SNCR\[16DC9000 - TCS - PALATKA COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR_R1.xls]PRIME CODE TCS

ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

LINE NO.	JE PRIME CODE	01 PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR DESCRIPTION	QTY.	UNIT	W.H./ UNIT	TOTAL W.H.'s	COST/ W.H.	TOTAL DIRECT LABOR	PROCESS EQUIPMENT UNIT COST	TOTAL PROCESS EQUIPMENT	MATERIAL UNIT COST	TOTAL MATERIAL	SUB CONTRACT UNIT COST	TOTAL SUB CONTRACTS	UNIT COST	TOTAL ALL COSTS
		DIRECT COST- DETAILS														
1		MAJOR EQUIPMENT														
2																
3	50	FUELTECH SNCR SYSTEM	1	LOT	1,350.00	1,350	$54.17	$73,131	$875,000	$875,000	$0.00	$0	$0.00	$0	$948,131	$948,131
4	50	LEVEL 1 NOZZLES (WITH RETRACTABLE LANCES)	6	EA	INCLUDED	0	$54.17	$0	INCL.	$0	$0.00	$0	$0.00	$0	$0	$0
5	50	RETRACTABLE NOZZLES	6	EA	INCLUDED	0	$54.17	$0	INCL.	$0	$0.00	$0	$0.00	$0	$0	$0
6	50	LEVEL 2 NOZZLES (FIXED POSITION NOZZLES)	3	EA	INCLUDED	0	$54.17	$0	INCL.	$0	$0.00	$0	$0.00	$0	$0	$0
7	50	DISTRIBUTION SKIDS	2	EA	INCLUDED	0	$54.17	$0	INCL.	$0	$0.00	$0	$0.00	$0	$0	$0
8	50	METERING SKID	1	EA	INCLUDED	0	$54.17	$0	INCL.	$0	$0.00	$0	$0.00	$0	$0	$0
11	50	PUMPING SKID	1	EA	INCLUDED	0	$54.17	$0	INCL.	$0	$0.00	$0	$0.00	$0	$0	$0
15	50															
16	50	UREA STORAGE TANK - 10' DIAMETER X 12' HIGH	1	EA	100.00	100	$54.17	$5,417	$14,000	$14,000	$0.00	$0	$0.00	$0	$19,417	$19,417
17	50	DIKE	1	EA	IN CONCRETE	0	$54.17	$0	$0	$0	IN CONCRETE	$0	$0.00	$0	$0	$0
18	50	LADDER	1	EA	8.00	8	$54.17	$433	$1,000	$1,000	$0.00	$0	$0.00	$0	$1,433	$1,433
19	50															
20	50	PIPING FROM UREA STORAGE TANK TO METERING SKID	1	LOT	IN PIPING	0	$54.17	$0	$0	$0	IN PIPING	$0	$0.00	$0	$0	$0
21	50	PIPING FROM METERING SKID TO PUMPING SKID	1	LOT	IN PIPING	0	$54.17	$0	$0	$0	IN PIPING	$0	$0.00	$0	$0	$0
22	50	PIPING FROM PUMPING SKID TO DISTRIBUTION SKIDS	1	LOT	IN PIPING	0	$54.17	$0	$0	$0	IN PIPING	$0	$0.00	$0	$0	$0
23	50															
24	50	NEW AIR COMPRESSOR	1	EA	200.00	200	$54.17	$10,834	$75,000	$75,000	$0.00	$0	$0.00	$0	$85,834	$85,834
27	50															
28	50															
29	50	FREIGHT	1	LOT	N / A	0	$54.17	$0	$57,900	$57,900	$0.00	$0	$0.00	$0	$57,900	$57,900
30	50	SHIMS AND GROUT	1	LOT	41.45	41	$54.17	$2,245	$0	$0	$15,344	$15,344	$0.00	$0	$17,589	$17,589
35																
36	50	TOTAL - MAJOR EQUIPMENT				1,699	$54.17	$92,062		$1,022,900		$15,344		$0		$1,130,305
51																
52																
53		DEMOLITION														
54																
66	51	*FACTORED FROM INSTALLED PROCESS EQUIPMENT COST*	1	LOT	469.47	469	$54.17	$25,432	$0	$0	$0	$0	$0	$0	$25,432	$25,432
67																
68	51	TOTAL - DEMOLITION				469	$54.17	$25,432		$0		$0		$0		$25,432
80																
81																
82		SITE IMPROVEMENTS														
83																
88	53	*FACTORED FROM INSTALLED PROCESS EQUIPMENT COST*	1	LOT	0.00	0	$45.91	$0	$0	$0	$0	$0	$56,515	$56,515	$56,515	$56,515
89																
90	53	TOTAL - SITE IMPROVEMENTS				0	$0.00	$0		$0		$0		$56,515		$56,515
91																
92																
93		PILING, CAISSONS														
94																
99	54	*FACTORED FROM INSTALLED PROCESS EQUIPMENT COST*	1	LOT	0.00	0	$45.91	$0	$0	$0	$0	$0	$79,121	$79,121	$79,121	$79,121
100																
101	54	TOTAL - PILING, CAISSONS	791	LF	0.00	0	$0.00	$0		$0		$0		$79,121	$100.00	$79,121
102																
103																
139		SPECIAL CONSTR. (SEISMIC CONTROL, PRE-ENGR BUILDINGS, ETC.)														
140																
141	55.380	MCC ROOM, 20' X 20'	400	SF	S / C	0	$45.91	$0	$0.00	$0	$0.00	$0	$200.00	$80,000	$200.00	$80,000
146																
147	55.380	TOTAL - SPECIAL CONSTRUCTION				0	$0.00	$0		$0		$0		$80,000		$80,000
148																
149																
187		CONCRETE														
188																
189	56	DIKE (INCLUDED IN FACTOR)				0	$45.91	$0	$0.00	$0	$0.00	$0	$0.00	$0	$0	$0
190	56															
193	56	*FACTORED FROM INSTALLED PROCESS EQUIPMENT COST*	1	LOT	369.31	369	$45.91	$16,955	$0	$0	$16,955	$16,955	$0	$0	$33,909	$33,909
194																
195	56	TOTAL - CONCRETE	31	CY	12.0	369	$45.91	$16,955		$0		$16,955		$0		$33,909
207																
208																
209		STRUCTURAL STEEL														

DETAIL DIRECT COST

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)

ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

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LINE NO.	JE PRIME CODE	01 PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR DESCRIPTION	QTY.	UNIT	W.H./ UNIT	TOTAL W.H.'s	COST/ W.H.	TOTAL DIRECT LABOR	PROCESS EQUIPMENT UNIT COST	TOTAL PROCESS EQUIPMENT	MATERIAL UNIT COST	TOTAL MATERIAL	SUB CONTRACT UNIT COST	TOTAL SUB CONTRACTS	UNIT COST	TOTAL ALL COSTS
		DIRECT COST- DETAILS														
210																
231	58	*FACTORED FROM INSTALLED PROCESS EQUIPMENT COST*	1	LOT	1,352.88	1,353	$50.13	$67,818	$0	$0	$135,637	$135,637	$0	$0	$203,455	$203,455
232																
233	58	TOTAL - STRUCTURAL STEEL	39	TN	35.0	1,353	$50.13	$67,818		$0		$135,637		$0		$203,455
267																
268																
269		PIPING														
270																
307	62	*FACTORED FROM INSTALLED PROCESS EQUIPMENT COST*	1	LOT	1,669.23	1,669	$54.17	$90,424	$0	$0	$101,727	$101,727	$0	$0	$192,152	$192,152
308																
309	62	TOTAL - PIPING	556	LF	3.00	1,669	$54.17	$90,424		$0		$101,727		$0		$192,152
310																
311																
312		INSULATION - PIPE, EQUIPMENT & DUCTWORK														
313																
314	63	UREA TANK (INCLUDED IN FACTOR)				0	$45.91	$0	$0.00	$0	$0.00	$0	$0.00	$0	$0.00	$0
316	63															
316	63	*FACTORED FROM INSTALLED PROCESS EQUIPMENT COST*	1	LOT	1,107.92	1,108	$45.91	$50,864	$0	$0	$0	$0	$50,864	$50,864	$101,727	$101,727
319																
320	63	TOTAL - INSULATION - PIPE, EQUIPMENT & DUCTWORK	1	LOT		1,108	$45.91	$50,864		$0		$0		$50,864		$101,727
321																
322																
323		INSTRUMENTATION														
324																
336	64	*FACTORED FROM INSTALLED PROCESS EQUIPMENT COST*	1	LOT	111.23	111	$50.81	$5,652	$11,303	$11,303	$11,303	$11,303	$0	$0	$28,258	$28,258
337																
338	64	TOTAL - INSTRUMENTATION	6	EA	20.00	111	$50.81	$5,652		$11,303		$11,303		$0		$28,258
339																
340																
341		ELECTRICAL														
342																
343	65	UREA TANK HEAT TRACING (INCLUDED IN FACTOR)				0	$50.81	$0	$0.00	$0	$0.00	$0	$0.00	$0	$0.00	$0
344	65															
345	65	TRANSFORMER - 13,800 V TO 480 V, RATED FOR 400 HP CONNECTED LOAD	1	EA	100.00	100	$50.81	$5,081	$35,000	$35,000	$0.00	$0	$0.00	$0	$40,081	$40,081
346	65															
355	65	TESTING AND STARTUP	1	LOT	5.00	5	$50.81	$254	$0.00	$0	$0.00	$0	$0.00	$0	$254.04	$254
356	65	FREIGHT	1	LOT	N / A	0	$50.81	$0	$2,100	$2,100	$0	$0	$0.00	$0	$2,100	$2,100
358	65															
360	65	*FACTORED FROM INSTALLED PROCESS EQUIPMENT COST*	1	LOT	444.93	445	$50.81	$22,606	$56,515	$56,515	$45,212	$45,212	$0	$0	$124,334	$124,334
361																
362	65	TOTAL - ELECTRICAL	2,200	LF	0.25	550	$50.81	$27,941		$93,615		$45,212		$0		$166,768
363																
364																
365		PAINTING, PROTECTIVE COATINGS														
366																
371	66	*FACTORED FROM INSTALLED PROCESS EQUIPMENT COST*	1	LOT	123.10	123	$45.91	$5,652	$0	$0	$5,652	$5,652	$0	$0	$11,303	$11,303
372																
373	66	TOTAL - PAINTING, PROTECTIVE COATINGS				123	$45.91	$5,652		$0		$5,652		$0		$11,303
386																
387																
388																
389																
390																
391		**TOTAL - DIRECT COST**				7,452	$51.37	$382,799		$1,127,818		$331,829		$266,600		$2,108,946

CONTRACTOR'S CONSTRUCTION INDIRECT COST - CONSTRUCTION SUPPORT LABOR

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)
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ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

JE PRIME CODE	DESCRIPTION	QTY.	UNIT	W.H./ UNIT	TOTAL W.H.'s	COST/ W.H.	TOTAL DIRECT LABOR	MATERIAL UNIT COST	TOTAL MATERIAL	SUB CONTRACT UNIT COST	TOTAL SUB CONTRACTS	TOTAL ALL COSTS
75	**CONSTRUCTION SUPPORT LABOR**											
	(LABOR COST ONLY)											
	CAPITAL - CONSTRUCTION SUPPORT LABOR - ALLOWANCE @ 20 % OF DIRECT LABOR HOURS FOR BELOW LISTED ITEMS	7,452	WH	0.20	1,490	$40.53	$60,409	$0	$0	$0	$0	$60,409
	CONS EQUIP OPERATION - CRANE				0	$40.53	$0	$0	$0	$0	$0	$0
	WELDER QUALIFICATIONS				0	$40.53	$0	$0	$0	$0	$0	$0
	RAINED OUT LABOR				0	$40.53	$0	$0	$0	$0	$0	$0
	SAFETY TRAINING				0	$40.53	$0	$0	$0	$0	$0	$0
	SCAFFOLDING (Rental Incl. W/ Constr. Eq. Rental)				0	$40.53	$0	$0	$0	$0	$0	$0
	UNLOAD AND STORE BULK MATERIAL				0	$40.53	$0	$0	$0	$0	$0	$0
	WAREHOUSEMAN				0	$40.53	$0	$0	$0	$0	$0	$0
	TOOL MAN				0	$40.53	$0	$0	$0	$0	$0	$0
	FIRE WATCH				0	$40.53	$0	$0	$0	$0	$0	$0
	YARD CREWS				0	$40.53	$0	$0	$0	$0	$0	$0
	SPECIAL HAULING / RIGGING				0	$40.53	$0	$0	$0	$0	$0	$0
	STARTUP - CRAFTSMEN				0	$40.53	$0	$0	$0	$0	$0	$0
	CLEAN UP				0	$40.53	$0	$0	$0	$0	$0	$0
	EMPLOYMENT & RANDOM DRUG TESTS				0	$40.53	$0	$0	$0	$0	$0	$0
	MOVE IN / MOVE OUT LABOR				0	$40.53	$0	$0	$0	$0	$0	$0
	WATER / ICE				0	$40.53	$0	$0	$0	$0	$0	$0
75	**TOTAL - CONSTRUCTION SUPPORT LABOR**				1,490		$60,409		$0		$0	$60,409

CONTRACTOR'S CONSTRUCTION INDIRECT COST - PREMIUM TIME

JE

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)
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ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

JE PRIME CODE	DESCRIPTION		TOTAL WEEKLY W.H.'S	TOTAL PREMIUM W.H.'S		PREMIUM COST ADDER	TOTAL COST
78	**PREMIUM & EFFICIENCY LOSS TIME CALCULATION WORKSHEET**						
	CAPITAL PREMIUM TIME COST: BASED ON BARE WAGE RATE OF:					$22.72	
	TOTAL CRAFT HOURS:			8,943	HRS		
	CRAFT HOURS WORKED ON 40 HR WEEK **(0 HRS PT)**	0.0%	0	0	HRS		
	CRAFT HOURS WORKED ON 50 HR WEEK **(10 HRS PT)**	100.0%	8,943	1,789	HRS	$13.06	$23,354
	CRAFT HOURS WORKED ON 60 HR WEEK **(20 HRS PT)**	0.0%	0	0	HRS	$13.06	$0
	CRAFT HOURS WORKED ON 70 HR WEEK **(30 HRS PT)**	0.0%	0	0	HRS	$13.06	$0
	CRAFT HOURS WORKED ON 84 HR WEEK **(44 HRS PT)**	0.0%	0	0	HRS	$13.06	$0
		100.0%	8,943	1,789	HRS		
	TOTAL CAPITAL PREMIUM TIME COST						**$23,354**
78	**T O T A L**						**$23,354**

CONTRACTOR'S CONSTRUCTION INDIRECT COST - NON-PAYROLL TAX, INSURANCE AND PERMITS

JE

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)
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ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

JE PRIME CODE	DESCRIPTION	QTY.	UNIT	PROCESS EQUIPMENT UNIT COST	TOTAL PROCESS EQUIPMENT	MATERIAL UNIT COST	TOTAL MATERIAL	SUB CONTRACT UNIT COST	TOTAL SUB CONTRACTS	TOTAL ALL COSTS
81	**NON-PAYROLL TAX, INSURANCE AND PERMITS**									
	SALES & USE TAX									
	6.5% OF EQUIPMENT	$1,127,818	EQ $	6.50%	$73,308					$73,308
	6.5% OF MATERIAL	$331,829	MAT'L $			6.50%	$21,569			$21,569
	6.5% ON 50% OF SUBCONTRACTS	$133,250	SUB $					6.50%	$8,661	$8,661
81	**TOTAL NON-PAYROLL TAX, INSURANCE AND PERMITS**				**$73,308**		**$21,569**		**$8,661**	**$103,538**

CONTRACTOR'S CONSTRUCTION INDIRECT COST - CRAFT START-UP ASSISTANCE

JE

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)
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ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

JE PRIME CODE	DESCRIPTION	QTY.	UNIT	W.H./ UNIT	TOTAL W.H.'s	COST/ W.H.	TOTAL DIRECT LABOR	PROCESS EQUIPMENT UNIT COST	TOTAL PROCESS EQUIPMENT	MATERIAL UNIT COST	TOTAL MATERIAL	SUB CONTRACT UNIT COST	TOTAL SUB CONTRACTS	TOTAL ALL COSTS
71	CRAFT START-UP ASSISTANCE													
	CRAFT START-UP SERVICES (3 CRAFT PERSONNEL @ 50 HOURS EACH)	3	WK	150.00	450	$74.00	$33,300	$0	$0	$0	$0	$0	$0	$33,300
71	TOTAL CRAFT START-UP ASSISTANCE						$33,300		$0		$0		$0	$33,300

CONTRACTOR'S CONSTRUCTION INDIRECT COST - CONTRACTOR'S CONSTRUCTION FEE

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)
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ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

JE PRIME CODE	DESCRIPTION	QTY.	UNIT	LABOR UNIT COST	TOTAL DIRECT LABOR	PROCESS EQUIPMENT UNIT COST	TOTAL PROCESS EQUIPMENT	MATERIAL UNIT COST	TOTAL MATERIAL	SUB CONTRACT UNIT COST	TOTAL SUB CONTRACTS	TOTAL ALL COSTS
99	CONTRACTOR'S CONSTRUCTION FEE											
	LABOR (INCLUDED IN WAGE RATES)	499,861	LAB$	9.1%	$45,597							$45,597
	EQUIPMENT	1,201,126	EQ$			0.00%	$0					$0
	MATERIAL	353,398	MAT$					15.00%	$53,010			$53,010
	SUBCONTRACT	337,763	SUB$							10.00%	$33,776	$33,776
99	TOTAL CONTRACTOR'S CONSTRUCTION FEE				$45,597		$0		$53,010		$33,776	$132,382

TOTAL CONTRACTOR'S CONSTRUCTION FEE AS A % OF TOTAL CONSTRUCTION COST - EQUIP. =	10.0%

TOTAL CONSTRUCTION COST LESS PROCESS EQUIPMENT = $1,323,404

PROJECT INDIRECT COST - CONSTRUCTION MANAGEMENT

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)
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ESTIMATE DATE: 11/27/06
REVISION NO.: 1
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JE PRIME CODE	DESCRIPTION	QTY.	UNIT	W.H./ UNIT	TOTAL W.H.'s	COST/ W.H.	TOTAL DIRECT LABOR	MATERIAL UNIT COST	TOTAL MATERIAL	SUB CONTRACT UNIT COST	TOTAL SUB CONTRACTS	UNIT COST	TOTAL ALL COSTS
88	TOTAL CONSTRUCTION MANAGEMENT												
	TOTAL - CONSTRUCTION MANAGEMENT	1	LOT		0	$0.00	$0	$0.00	$0	$192,798	$192,798	$192,798	$192,798
88	TOTAL - CONSTRUCTION MANAGEMENT				0		$0		$0		$192,798		$192,798

PROJECT INDIRECT COST - ENGINEERING PROFESSIONAL SERVICES

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)
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ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

JE PRIME CODE	DESCRIPTION	QTY.	UNIT	W.H./ UNIT	TOTAL W.H.'s	COST/ W.H.	LABOR UNIT COST	TOTAL DIRECT LABOR	PROCESS EQUIPMENT UNIT COST	TOTAL PROCESS EQUIPMENT	MATERIAL UNIT COST	TOTAL MATERIAL	SUB CONTRACT UNIT COST	TOTAL SUB CONTRACTS	UNIT COST	TOTAL ALL COSTS
90	ENGINEERING PROFESSIONAL SERVICES															
	JACOBS	1	LOT		0	$0.00	$0.00	$0	$0	$0	$0	$0	$424,953	$424,953	$424,953	$424,953
90	TOTAL ENGINEERING PROFESSIONAL SERVICES							$0		$0		$0		$424,953		$424,953

PROJECT INDIRECT COST - STUDY COST

JE

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)
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ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

JE PRIME CODE	DESCRIPTION	QTY.	UNIT	TOTAL DIRECT LABOR	PROCESS EQUIPMENT UNIT COST	TOTAL PROCESS EQUIPMENT	MATERIAL UNIT COST	TOTAL MATERIAL	SUB CONTRACT UNIT COST	TOTAL SUB CONTRACTS	TOTAL ALL COSTS
90	**STUDY COST**										
	STUDY COST	1	LOT	$0	$0	$0	$0	$0	$50,000	$50,000	$50,000
90	**STUDY COST**			$0		$0		$0		$50,000	$50,000

PROJECT INDIRECT COST - OUTSIDE CONSULTANT SERVICES

JE

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)
G:\ESTIMATI\GEORPAC\FLORIDA\PALATKA\16DC9000 - BART BOILER PROGRAM\PALATKA COMBINATION BOILER NO. 4 - SNCR\[16DC9000 - TCS - PALATKA COMBINATION BOILER NO. 4 - NOX REMO

ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

JE PRIME CODE	DESCRIPTION	QTY.	UNIT	TOTAL DIRECT LABOR	PROCESS EQUIPMENT UNIT COST	TOTAL PROCESS EQUIPMENT	MATERIAL UNIT COST	TOTAL MATERIAL	SUB CONTRACT UNIT COST	TOTAL SUB CONTRACTS	TOTAL ALL COSTS
96	**OUTSIDE CONSULTANT SERVICES**										
	OUTSIDE CONSULTANT SERVICES	1	LOT	$0	$0	$0	$0	$0	$100,000	$100,000	$100,000
96	**TOTAL OUTSIDE CONSULTANT SERVICES**			$0		$0		$0		$100,000	$100,000

PROJECT INDIRECT COST - OWNER'S COST

JE

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)
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ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

JE PRIME CODE	DESCRIPTION	QTY.	UNIT	TOTAL DIRECT LABOR	PROCESS EQUIPMENT UNIT COST	TOTAL PROCESS EQUIPMENT	MATERIAL UNIT COST	TOTAL MATERIAL	SUB CONTRACT UNIT COST	TOTAL SUB CONTRACTS	TOTAL ALL COSTS
91	**OWNER'S COST**										
	OWNER'S COST	1	LOT	$0	$0	$0	$0	$0	$128,928	$128,928	$128,928
91	**TOTAL OWNER'S COST**			$0		$0		$0		$128,928	$128,928

PROJECT INDIRECT COST - SPARE PARTS

JOB: BART BOILER PROGRAM - PALATKA -
COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)
G:\ESTIMAT\GEORPAC\FLORIDA\PALATKA\16DC9000 - BART BOILER PROGRAM\PALATKA COMBINATION BOILER NO. 4 - SNCR\[16DC9000 - TCS - PALATKA COMBINATION BOILER NO. 4 - NOX REMOVAL

ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSOI
EST. FILE #: 06212

JE PRIME CODE	DESCRIPTION	QTY.	UNIT	TOTAL DIRECT LABOR	PROCESS EQUIPMENT UNIT COST	TOTAL PROCESS EQUIPMENT	MATERIAL UNIT COST	TOTAL MATERIAL	SUB CONTRACT UNIT COST	TOTAL SUB CONTRACTS	TOTAL ALL COSTS
70	**SPARE PARTS**										
	SPARE PARTS - ALLOWANCE OF 5% OF EQUIPMENT COST	1	LOT	$0	$56,391	$56,391	$0	$0	$0	$0	$56,391
70	**TOTAL SPARE PARTS**			$0		$56,391		$0		$0	$56,391

PROJECT NDIRECT COST - NON-CRAFT START-UP ASSISTANCE

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)
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ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

JE PRIME CODE	DESCRIPTION	QTY.	UNIT	W.H./ UNIT	TOTAL W.H.'s	COST/ W.H.	TOTAL DIRECT LABOR	PROCESS EQUIPMENT UNIT COST	TOTAL PROCESS EQUIPMENT	MATERIAL UNIT COST	TOTAL MATERIAL	SUB CONTRACT UNIT COST	TOTAL SUB CONTRACTS	TOTAL ALL COSTS
71	**NON-CRAFT START-UP ASSISTANCE**													
	PROFESSIONAL SERVICES START-UP	4	WK	150.00	600	$83.25	$49,950	$0	$0	$0	$0	$0	$0	$49,950
	PROFESSIONAL SERVICES START-UP - EXPENSES	4	WK	0.00	0	$0.00	$0	$0	$0	$0	$0	$4,800	$19,200	$19,200
	VENDOR START-UP SERVICES	1	LOT		0	$0.00	$0	$0	$0	$0	$0	$50,000	$50,000	$50,000
71	**TOTAL NON-CRAFT START-UP ASSISTANCE**						$49,950		$0		$0		$69,200	$119,150

PROJECT INDIRECT COSTS - ALLOWANCE FOR UNFORESEEN

JE

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)

ESTIMATE DATE: 11/27/08
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

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PRIME								PERCENTAGES				DOLLARS				
CODE	PRIME CODE	DESCRIPTION	LABOR	EQUIPMENT	MATERIAL	SUBCONT.	TOTAL COST	LABOR	EQUIP.	MAT'L	S/C	LABOR	EQUIPMENT	MATERIAL	SUBCONT.	TOTAL COST
		DIRECT COSTS														
98	50	MAJOR EQUIPMENT	$92,062	$1,022,900	$15,344	$0	$1,130,305	10.0%	10.0%	10.0%	10.0%	$9,206	$102,290	$1,534	$0	$113,031
98	51	DEMOLITION	$25,432	$0	$0	$0	$25,432	10.0%	10.0%	10.0%	10.0%	$2,543	$0	$0	$0	$2,543
98	52	SITE EARTHMOVING	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
98	53	SITE IMPROVEMENTS	$0	$0	$0	$56,515	$56,515	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$5,652	$5,652
98	54	PILING, CAISSONS	$0	$0	$0	$79,121	$79,121	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$7,912	$7,912
98	55	BUILDINGS	$0	$0	$0	$80,000	$80,000	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$8,000	$8,000
98	56	CONCRETE	$16,955	$0	$16,955	$0	$33,909	10.0%	10.0%	10.0%	10.0%	$1,695	$0	$1,695	$0	$3,391
98	57	MASONRY, REFRACTORY	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
98	58	STRUCTURAL STEEL	$67,818	$0	$135,637	$0	$203,456	10.0%	10.0%	10.0%	10.0%	$6,782	$0	$13,564	$0	$20,345
98	59	ROOFING AND SIDING	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
98	60	FIRE PROOFING	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
98	61	PROCESS DUCTWORK (NON-BUILDING)	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
98	62	PIPING	$90,424	$0	$101,727	$0	$192,152	10.0%	10.0%	10.0%	10.0%	$9,042	$0	$10,173	$0	$19,215
98	63	INSULATION - PIPE, EQUIPMENT & DUCTWORK	$50,864	$0	$0	$50,864	$101,727	10.0%	10.0%	10.0%	10.0%	$5,086	$0	$0	$5,086	$10,173
98	64	INSTRUMENTATION	$5,652	$11,303	$11,303	$0	$28,258	10.0%	10.0%	10.0%	10.0%	$565	$1,130	$1,130	$0	$2,826
98	65	ELECTRICAL	$27,941	$93,615	$45,212	$0	$166,768	10.0%	10.0%	10.0%	10.0%	$2,794	$9,362	$4,521	$0	$16,677
98	66	PAINTING, PROTECTIVE COATINGS	$5,652	$0	$5,652	$0	$11,303	10.0%	10.0%	10.0%	10.0%	$565	$0	$565	$0	$1,130
98	67	FURNITURE, LAB & SHOP EQUIPMENT	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
		TOTAL DIRECT COSTS	$382,799	$1,127,818	$331,829	$266,500	$2,108,946					$38,280	$112,782	$33,183	$26,650	$210,895
		CONSTRUCTION INDIRECT COSTS														
98	75	CONSTRUCTION SUPPORT LABOR	$60,409	$0	$0	$0	$60,409	10.0%	10.0%	10.0%	10.0%	$6,041	$0	$0	$0	$6,041
98	76	TEMPORARY CONSTRUCTION FACILITIES (IN WAGE RATE	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
98	78	PREMIUM TIME	$23,354	$0	$0	$0	$23,354	10.0%	10.0%	10.0%	10.0%	$2,335	$0	$0	$0	$2,335
98	79	CRAFT FRINGE BENEFITS (IN WAGE RATES)	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
98		CRAFT PER DIEM ($7 PER HOUR ON 100 % OF THE HOURS	$0	$0	$0	$62,601	$62,601	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$6,260	$6,260
98	80	PAYROLL TAXES & INSURANCE (IN WAGE RATES)	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
98	83	SMALL TOOLS (IN WAGE RATES)	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
98	84	CONSUMABLE SUPPLIES (IN WAGE RATES)	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
98	85	CONSTRUCTION EQUIPMENT (IN WAGE RATES)	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
98	87	FIELD STAFF (IN WAGE RATES)	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
98	81	NON-PAYROLL TAX, INSURANCE & PERMITS	$0	$73,308	$21,569	$8,661	$103,538	10.0%	10.0%	10.0%	10.0%	$0	$7,331	$2,157	$866	$10,354
98	93	CONSTRUCTION HOME OFFICE COST (INC. WITH CONTRA	$0	$0	$0	$0	$0	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$0	$0
98	71	CRAFT START-UP ASSISTANCE	$33,300	$0	$0	$0	$33,300	10.0%	10.0%	10.0%	10.0%	$3,330	$0	$0	$0	$3,330
98	99	CONTRACTOR'S CONSTRUCTION HOME OFFICE & FEE	$45,597	$0	$53,010	$33,776	$132,382	10.0%	10.0%	10.0%	10.0%	$4,560	$0	$5,301	$3,378	$13,238
		TOTAL CONSTRUCTION INDIRECT COSTS										$16,266	$7,331	$7,458	$10,504	$41,558
		TOTAL CONSTRUCTION COSTS (TCC)	$545,458	$1,201,126	$406,407	$371,539	$2,524,531					$54,546	$120,113	$40,641	$37,154	$252,453
98	88	CONSTRUCTION MANAGEMENT	$0	$0	$0	$192,798	$192,798	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$19,280	$19,280
98	90	ENGINEERING PROFESSIONAL SERVICES	$0	$0	$0	$424,953	$424,953	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$42,496	$42,495
98	90	STUDY COST	$0	$0	$0	$50,000	$50,000	10.0%	10.0%	10.0%	0.0%	$0	$0	$0	$0	$0
98	96	OUTSIDE CONSULTANT SERVICES	$0	$0	$0	$100,000	$100,000	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$10,000	$10,000
98	91	OWNER'S COST	$0	$0	$0	$128,928	$128,928	10.0%	10.0%	10.0%	10.0%	$0	$0	$0	$12,893	$12,893
98	70	SPARE PARTS	$0	$56,391	$0	$0	$56,391	10.0%	10.0%	10.0%	10.0%	$0	$5,639	$0	$0	$5,639
98	71	NON-CRAFT START-UP ASSISTANCE	$49,950	$0	$0	$69,200	$119,150	10.0%	10.0%	10.0%	10.0%	$4,995	$0	$0	$6,920	$11,915
98	98	ALLOWANCE FOR UNFORESEEN	N/A													
98	98	ESCALATION	N/A													
98	99	EPC FEE	N/A													
		CAPITAL INTEREST	N/A													
		ROUND OFF	N/A													
98		**TOTAL PROJECT COSTS**	$595,408	$1,257,517	$406,407	$1,337,418	$3,596,750					$59,541	$125,752	$40,641	$128,742	$354,675

PROJECT INDIRECT COSTS - ESCALATION

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000
CONSTRUCTION DURATION: TBD
ESTIMATE TYPE: CLASS 5 (+/- 30%)

ESCALATION IS BASED ON THE ASSUMPTION THAT ALL WORK WILL BE COMPLETED BY DECEMBER 31, 2006

ESTIMATE DATE: 11/27/06
REVISION NO.: 1
ESTIMATOR: WSJ
PROJECT MGR: LELAND HENSON
EST. FILE #: 06212

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PRIME								PERCENTAGES				DOLLARS				
CODE	PRIME CODE	DESCRIPTION	LABOR	EQUIPMENT	MATERIAL	SUBCONT.	TOTAL COST	LABOR	EQUIP.	MAT'L	S/C	LABOR	EQUIPMENT	MATERIAL	SUBCONT.	TOTAL COST
		DIRECT COSTS														
98	50	MAJOR EQUIPMENT	$92,062	$1,022,900	$15,344	$0	$1,130,305	0.0%	10.0%	10.0%	5.0%	$0	$102,290	$1,534	$0	$103,824
98	51	DEMOLITION	$25,432	$0	$0	$0	$25,432	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	52	SITE EARTHMOVING	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	53	SITE IMPROVEMENTS	$0	$0	$0	$56,515	$56,515	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$2,826	$2,826
98	54	PILING, CAISSONS	$0	$0	$0	$79,121	$79,121	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$3,956	$3,956
98	55	BUILDINGS	$0	$0	$0	$80,000	$80,000	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$4,000	$4,000
98	56	CONCRETE	$16,955	$0	$16,955	$0	$33,909	0.0%	10.0%	15.0%	5.0%	$0	$0	$2,543	$0	$2,543
98	57	MASONRY, REFRACTORY	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	58	STRUCTURAL STEEL	$67,818	$0	$135,637	$0	$203,456	0.0%	10.0%	15.0%	5.0%	$0	$0	$20,345	$0	$20,345
98	59	ROOFING AND SIDING	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	60	FIRE PROOFING	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	61	PROCESS DUCTWORK (NON-BUILDING)	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	62	PIPING	$90,424	$0	$101,727	$0	$192,152	0.0%	10.0%	15.0%	5.0%	$0	$0	$15,259	$0	$15,259
98	63	INSULATION - PIPE, EQUIPMENT & DUCTWORK	$50,864	$0	$0	$50,864	$101,727	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$2,543	$2,543
98	64	INSTRUMENTATION	$5,652	$11,303	$11,303	$0	$28,258	0.0%	10.0%	15.0%	5.0%	$0	$1,130	$1,695	$0	$2,826
98	65	ELECTRICAL	$27,941	$93,615	$45,212	$0	$166,768	0.0%	10.0%	15.0%	5.0%	$0	$9,362	$6,782	$0	$16,143
98	66	PAINTING, PROTECTIVE COATINGS	$5,652	$0	$5,652	$0	$11,303	0.0%	10.0%	10.0%	5.0%	$0	$0	$565	$0	$565
98	67	FURNITURE, LAB & SHOP EQUIPMENT	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
		TOTAL DIRECT COSTS	$382,799	$1,127,818	$331,829	$266,500	$2,108,948					$0	$112,782	$48,725	$13,325	$174,831
		CONSTRUCTION INDIRECT COSTS														
98	75	CONSTRUCTION SUPPORT LABOR	$60,409	$0	$0	$0	$60,409	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	76	TEMPORARY CONSTRUCTION FACILITIES (IN WAGE RATE	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	78	PREMIUM TIME	$23,354	$0	$0	$0	$23,354	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	79	CRAFT FRINGE BENEFITS (IN WAGE RATES)	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98		CRAFT PER DIEM ($7 PER HOUR ON 100 % OF THE HOURS	$0	$0	$0	$62,601	$62,601	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$3,130	$3,130
98	80	PAYROLL TAXES & INSURANCE (IN WAGE RATES)	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	83	SMALL TOOLS (IN WAGE RATES)	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	84	CONSUMABLE SUPPLIES (IN WAGE RATES)	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	85	CONSTRUCTION EQUIPMENT (IN WAGE RATES)	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	87	FIELD STAFF (IN WAGE RATES)	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	81	NON-PAYROLL TAX, INSURANCE & PERMITS	$0	$73,308	$21,569	$8,661	$103,538	0.0%	10.0%	10.0%	5.0%	$0	$7,331	$2,157	$433	$9,921
98	93	CONSTRUCTION HOME OFFICE COST (INC. WITH CONTRA	$0	$0	$0	$0	$0	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	71	*CRAFT START-UP ASSISTANCE*	$33,300	$0	$0	$0	$33,300	0.0%	10.0%	10.0%	5.0%	$0	$0	$0	$0	$0
98	99	CONTRACTOR'S CONSTRUCTION HOME OFFICE & FEE	$45,597	$0	$53,010	$33,778	$132,382	0.0%	10.0%	10.0%	5.0%	$0	$0	$5,301	$1,689	$6,990
		TOTAL CONSTRUCTION INDIRECT COSTS										$0	$7,331	$7,458	$5,252	$20,041
		TOTAL CONSTRUCTION COSTS (TCC)	$545,458	$1,201,126	$406,407	$371,639	$2,524,531					$0	$120,113	$56,182	$18,577	$194,872
98	88	CONSTRUCTION MANAGEMENT	$0	$0	$0	$192,798	$192,798	0.0%	0.0%	0.0%	0.0%	$0	$0	$0	$0	$0
98	90	ENGINEERING PROFESSIONAL SERVICES	$0	$0	$0	$424,953	$424,953	0.0%	0.0%	0.0%	0.0%	$0	$0	$0	$0	$0
98	90	STUDY COST	$0	$0	$0	$50,000	$50,000	0.0%	0.0%	0.0%	0.0%	$0	$0	$0	$0	$0
98	96	OUTSIDE CONSULTANT SERVICES	$0	$0	$0	$100,000	$100,000	0.0%	0.0%	0.0%	5.0%	$0	$0	$0	$5,000	$5,000
98	91	OWNER'S COST	$0	$0	$0	$128,928	$128,928	0.0%	0.0%	0.0%	5.0%	$0	$0	$0	$6,446	$6,446
98	70	SPARE PARTS	$0	$56,391	$0	$0	$56,391	0.0%	10.0%	0.0%	0.0%	$0	$5,639	$0	$0	$5,639
98	71	NON-CRAFT START-UP ASSISTANCE	$49,950	$0	$0	$69,200	$119,150	0.0%	0.0%	0.0%	5.0%	$0	$0	$0	$3,460	$3,460
98	98	ALLOWANCE FOR UNFORESEEN	N / A													
98	98	ESCALATION	N / A													
98	99	EPC FEE	N / A													
		CAPITAL INTEREST	N / A													
		ROUND OFF	N / A													
98		**TOTAL PROJECT COSTS**	$595,408	$1,257,517	$406,407	$1,337,418	$3,596,750					$0	$125,752	$56,182	$33,483	$215,416

CONSTRUCTION "ALL-IN" WAGE RATE

JOB: BART BOILER PROGRAM - PALATKA - COMBINATION BOILER NO. 4 - NOX REMOVAL - SNCR
CLIENT: GEORGIA PACIFIC
LOCATION: PALATKA, FLORIDA
JOB NUMBER: 16DC9000

	CRAFT			CRAFT			CRAFT			CRAFT			CRAFT			CRAFT		
	CONCRETE / MASONRY			STRUCTURAL STEEL			PIPING & MECHANICAL			INSTRUMENTATION			ELECTRICAL			SUPPORT (INC. OPERATORS)		
ITEM	NOTES	%	COST	NOTES	%	COST	NOTES	%	COST	NOTES	%	COST	NOTES	%	COST	NOTES	%	COST
BASE JOURNEYMAN			$22.50			$22.50			$22.50			$22.50			$22.50			$21.50
COMPOSITE RATE		87.35%	$19.65		96.41%	$21.69		99.86%	$22.47		98.78%	$22.23		98.78%	$22.23		97.37%	$20.93
PAYROLL TAXES & INSURANCES:	33.60%																	
WORKMEN'S COMPENSATION		14.70%	$2.89		14.70%	$3.19		14.70%	$3.30		14.70%	$3.27		14.70%	$3.27		14.70%	$3.08
GENERAL LIABILITY		3.95%	$0.78		3.95%	$0.86		3.95%	$0.89		3.95%	$0.88		3.95%	$0.88		3.95%	$0.83
EXCESS LIABILITY		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00
FICA		7.65%	$1.50		7.65%	$1.66		7.65%	$1.72		7.65%	$1.70		7.65%	$1.70		7.65%	$1.60
FUI		0.80%	$0.16		0.80%	$0.17		0.80%	$0.18		0.80%	$0.18		0.80%	$0.18		0.80%	$0.17
SUI		6.50%	$1.28		6.50%	$1.41		6.50%	$1.46		6.50%	$1.44		6.50%	$1.44		6.50%	$1.36
OTHER		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00
FRINGES		12.50%	$2.46		12.50%	$2.71		12.50%	$2.81		12.50%	$2.78		12.50%	$2.78		12.50%	$2.62
PREMIUM TIME		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00
CONSTRUCTION SUPPORT LABOR		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00
TEMPORARY FACILITIES		7.50%	$1.47		7.50%	$1.63		7.50%	$1.69		7.50%	$1.67		7.50%	$1.67		7.50%	$1.57
SMALL TOOLS		7.50%	$1.47		7.50%	$1.63		7.50%	$1.69		7.50%	$1.67		7.50%	$1.67		7.50%	$1.57
CONSUMABLES		7.50%	$1.47		10.00%	$2.17		10.00%	$2.25		7.50%	$1.67		7.50%	$1.67		7.50%	$1.57
FIELD STAFF		25.00%	$4.91		25.00%	$5.42		35.00%	$7.86		35.00%	$7.78		35.00%	$7.78		25.00%	$5.23
EQUIPMENT RENTAL		40.00%	$7.86		35.00%	$7.59		35.00%	$7.86		25.00%	$5.56		25.00%	$5.56		0.00%	$0.00
CONSTRUCTION HOME OFFICE (ON TCS SHEET)		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00
PER DIEM		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00
CONTRACTOR FEE (ON TCS SHEET)		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00		0.00%	$0.00
TOTAL WAGE RATE WITH FEE		**233.60%**	**$45.81**		**231.10%**	**$50.13**		**241.10%**	**$54.17**		**228.60%**	**$50.81**		**228.60%**	**$50.81**		**193.60%**	**$40.53**

ATTACHMENT II

Appendix A:
Basis of Estimated Costs

BASIS OF ESTIMATED COSTS

GEORGIA PACIFIC
PALATKA, FLORIDA
REGIONAL HAZE / BOILER BART PROGRAM
JACOBS PROJECT NO. 16DC9000

GENERAL

The purpose of these cost estimates is to provide Georgia Pacific with a Feasibility Study Level Report in 2006 dollars with an accuracy range of ± 30 % for the Regional Haze/ Boiler BART Program at the Wauna, Oregon Mill.

Estimates were prepared by Jacobs for various SO_2 and NO_X control technologies for the boilers which where put in place or under construction between August 7, 1962 and August 7, 1977. These cost estimates were prepared in such a manner to ensure that each boiler proposed control technology and related cost estimate would stand alone on its own merit. This approach was selected to better address the uncertainty that will exist between which project or combination of projects might ultimately be implemented to meet the emissions targets established for the EPA Regional Haze / Boiler BART 2013 compliance date. Certain site specific conditions and / or the presence of alternate control technologies in the future may ultimately impact the overall project costs and feasibility of these projects if several of these projects are implemented concurrently on any given site.

In addition, the numbers used in this estimate for equipment cost do not always reflect the exact dollar amount that was provided by a vendor and reported in Appendix D. In many cases, Jacobs has used their sound engineering judgment and previous experience to change these prices. These changes may be for many reasons including but not limited to: adding or removing installation costs, adjusting for construction with a more expensive material, adding or removing options, increasing the controls included, etc.

In order to allow for air in-leakage in the existing Boilers, $100,000 has been added to each estimate to locate and repair any areas where excessive air infiltration may be occurring. This is required to ensure that any control technologies installed operate as they were designed.

GP plans to utilize the results from this feasibility study report and cost estimate(s) to support the Regional Haze / Boiler BART documentation submittal requirements to the individual States. This will establish the viability for installing the Boiler BART Control Technologies on these respective site boilers or whether to de-rate or decommission them to a capacity level below BART-eligibility.

At the time of issue, this estimate reflects the fair market value for construction costs, based upon 2006 dollars, in the Wauna, Oregon area.

BASIS OF ESTIMATED COSTS

ESTIMATE APPROACH

The estimate is based on Jacobs providing Engineering, Construction Management and Procurement Services.

For the basis of the cost estimate, detailed engineering, procurement and construction activities are assumed be completed by December 31, 2006.

WAGE RATES

This estimate is based on Union Wage Rates. The wage rates used in this estimate are composite all-in rates. The base journeyman rates range from $28.34 to $33.84. Jacobs established a crew mix for each craft, ranging from 89.98 % to 97.67 % of the base journeyman rate - see the All-In Wage Rate Sheet in the Estimate Detail Printout. Included in the wage rates are the following:

- **81 - PAYROLL TAXES AND INSURANCE**

  Payroll Taxes and Insurance are included at 28.1 % of bare craft labor.

- **79 - CRAFT FRINGE BENEFITS**

  Union Craft Fringe Benefits are included ranging from 35.11 % to 47.70 % of bare craft labor.

- **76 - TEMPORARY CONSTRUCTION FACILITIES**

  Temporary Construction Facilities include Contractor's office supplies, PC's, copiers, postage, phones, Fed Ex, temporary sanitary facilities, mobilization, trash removal and temporary lights. These items are calculated at 7.5% of bare craft labor.

- **83 & 84 - SMALL TOOLS AND CONSUMABLES**

  Small tools are included in the estimate at 7.5 % of bare craft labor. Construction consumables are included in the estimate at 7.5 % to 10 % of bare craft labor.

- **87 - CONTRACTORS FIELD STAFF**

  Field staff includes all contractors' field support staff except for craft foremen which are included in the crew mix calculations. Contractors Field Staff is calculated at 25 % to 35 % of bare craft labor based on the type of work being performed.

- **85 - CONSTRUCTION EQUIPMENT RENTAL**

  Construction equipment rental includes the contractors' automotive equipment, general equipment and small cranes. This construction equipment cost is calculated at 25 % to 40 % of bare craft labor based on the discipline - concrete, steel, pipe, electrical, etc. - being supported - see the All-In Wage Rate Sheet in the Estimate Detail Printout for the percent used for each discipline. If required, a line item is listed in the estimate for situations that require large cranes not covered by the allowance carried in the rate.

- **93 – CONTRACTOR'S HOME OFFICE**

  Contractor's Home Office cost includes time for Project Manager, accounting, safety, quality control, etc. is included in the Contractor's Fee.

- **99 - CONTRACTOR'S FEE**

  Contractor's fee is included in the estimate at 10 % of contractor's construction cost.

- **75 - CONTRUCTION SUPPORT LABOR**

  Construction Support Labor includes drug testing, safety training, fire watch, final cleanup, yard crews, etc. This cost is calculated as 20 % of bare craft labor.

DIRECT COSTS

50 - MAJOR EQUIPMENT

Vendor budget quotes were received for the Major Equipment.

Pump and motor installation hours are from Jacobs Standards. Other equipment installation cost items are based on historical experience.

Freight cost is included at 6 % of equipment cost.

51 – DEMOLITION AND RELOCATION

Demolition cost is factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

53 - SITE IMPROVEMENTS

Site Improvement costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

56 – CONCRETE

Concrete costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

58 – STRUCTURAL STEEL

Structural Steel costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

BASIS OF ESTIMATED COSTS

62 – PIPING

Piping costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

63 – INSULATION

Insulation costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

64 – INSTRUMENTATION

Instrumentation costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

65 – ELECTRICAL

Electrical Costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

66 – PAINTING

Painting costs are factored from installed process equipment cost but have been adjusted, as required, to reflect specific site requirements.

INDIRECT COSTS

70 – SPARE PARTS

An allowance for Spare Parts of 5 % of the process equipment cost is included.

78 - PREMIUM TIME

Premium Time is included based on the assumption that 100 % of the craft labor hours will be worked on a 50-hour week.

XX - CRAFT PER DIEM

Craft Per Diem is included at $7.00 per craft hour for all workers.

81 - NON-PAYROLL TAXES, INSURANCE AND PERMITS

Sales Tax is included at 5 % on equipment, materials and 5 % on 50 % of subcontract costs.

88 - CONSTRUCTION MANAGEMENT

Construction Management is estimated at 4.5 % of Total Installed Cost.

BASIS OF ESTIMATED COSTS

90 – ENGINEERING PROFESSIONAL SERVICES

Detail Design Engineering is estimated at 10 % of Total Installed Cost.

91 – OWNER'S COST

Owner's Cost is included at approximately 3 % of Total Installed Cost.

96 – OUTSIDE CONSULTANT SERVICES

An allowance of $100,000 is carried in the estimates for Outside Consultant Services.

98 – CONTINGENCY

Contingency is included in the estimate at 10 % of labor, equipment, material and subcontract costs.

This Contingency is part of the estimated project cost and is to cover unusual weather conditions, productivity issues, increases in costs not covered by contractual provisions, delays in delivery of equipment or materials, etc. It does not cover cost of additional work or scope changes after the definition of the project has been frozen for the estimate.

98 – ESCALATION

Escalation is based on the assumption that all work will be completed by December 31, 2006. No escalation is included for labor. Escalation is included at 10 % on equipment, 10 % on all material except for concrete, steel, pipe, instrumentation and electrical material which is included at 15 % and 5 % on subcontract cost.

BASIS OF ESTIMATED COSTS

ITEMS NOT INCLUDED

The following is a list of items not included in this estimate:

- Cost of Land
- Cost of borrowing money
- Cost of operating supplies
- Property taxes
- Hazardous materials handling or disposal
- All Risk Insurance
- Payment and Performance Bond
- Permits, Fees and Licenses

ITEMS AFFECTING THE COST ESTIMATE

Items, which may change the estimated construction cost, include, but are not limited to:

- Modifications to the scope of work included in this estimate
- Above normal escalation in material costs due to market availability and demands
- Special phasing requirements
- Restrictive technical specifications
- Volume discounts on National agreements
- Sole source specifications of materials or products
- Bids delayed beyond the projected schedule
- Sales and Use Tax exemptions
- Labor disputes or difficulties

ATTACHMENT III

9. Performance and Guarantees

It is recognized that the performance of the equipment covered in this proposal cannot be exactly predicted for every possible operating condition. In consequence, any predicted performance data submitted is intended to show probable operating results.

JANSEN will work with G-P to better define the performance guarantees once the boiler evaluation phase of the work has been completed.

All performance data listed here are based on the conditions stated below and are to be substantiated or revised based on the Phase 1 performance testing and evaluation done by JANSEN at the initiation of the project.

9.1 Predicted Performance

Predicted performance data is submitted for G-P's convenience only. Such data is not offered by JANSEN, or to be construed by G-P as a proposal, offer, contract obligation, representation, warranty, or guarantee.

Table 9-1 provides predicted future operating conditions for waste wood firing only and combination of waste wood and natural gas.

Table 9.1 Predicted Performance			
	Units	**Waste Wood Only**	**MCR on Wood and Natural Gas**
Total Steam Production	lb/hr	262,500	360,000
Steam Production from Waste Wood	lb/hr	262,500	293,000
Wood Fuel Burned (as-fired wet)	ton/hr	50.0	56.1
Wood Fuel Burned (as-fired wet)	ton/day	1,200	1,346
Natural gas	scfh	0.0	92,243
No. 6 Fuel Oil	lb/hr	0.0	0.0
Waste Wood Fuel Moisture Content	%	50	50
Feedwater Temperature	°F	445	445
Flue Gas O_2 at Boiler Bank Outlet	vol. %, wet	4.1	4.1
Total Combustion Air Flow	lb/hr	407,800	539,200
Air Temperature from TAH	°F	523	559
Flue Gas Temperature from TAH	°F	420	477
Boiler Thermal Efficiency	%	65.7	66.4
Total Heat Input	10^6 Btu/hr-ft^2	412.9	558.3
Grate Heat Release	10^6 Btu/hr-ft^2	1.07	1.2
Particulate Matter at Generating Bank Outlet	grains/dscf @8% O_2	1.15	1.50

9.2 Fuel Quality

The performance information and performance guarantees provided in this section pertain to operation of the unit while burning waste wood fuel and natural gas that are similar in elemental composition (ultimate analysis), moisture content, and heating value as listed in Table 9-2.

9.3 Performance Guarantees

The guarantees presented below are subject to the conditions specified in this section at the waste wood and natural gas quantities specified in Table 9-1.

The fuel used during the performance testing shall have a moisture content, nitrogen content, and heating value not less favorable than the values in Table 9-2. The remaining fuel components specified in Table 9-2 may vary by ±10% during the testing. The waste wood size distribution is to be as described below:

100% shall be smaller than 4 inches in any direction, a maximum of 50% shall pass through a 1/4 inch screen, and no more than 25% shall pass through a 1/8 inch screen.

Table 9-2. Fuel Composition

	Unit	Waste Wood	Natural Gas
Carbon	%, dry	49.8	69.3
Hydrogen	%, dry	6.1	22.7
Nitrogen *	%, dry	<0.2	8.0
Sulfur	%, dry	0.0	0.0
Oxygen	%, dry	42.5	0.0
Ash	%, dry	1.5	0.0
Moisture Content	%, as-received	50	0.0
HHV (Dry)	Btu/lb	8,200	23,000
HHV (Wet)	Btu/lb	4,100	23,000

*Nitrogen content to be determined by Kjeldahl method

9.3.1 Steam Generation Rate

9.3.1.1 JANSEN guarantees that the No. 4 Combination Boiler will be able to sustain an average steam generation rate of 360,000 lb/hr on waste wood and natural gas with the quantity of steam from waste wood of 293,000lb/hr, provided that the fuel qualities are as specified in Table 9-2 over an eight (8) hour test period.

9.3.1.2 JANSEN guarantees that the No. 4 Combination Boiler will be able to sustain an average steam generation rate of 262,500 lb/hr on waste wood only, with the fuel qualities specified in Table 9-2 over an eight (8) hour test period.

9.3.2 Emissions

Under the conditions specified in paragraph 9.3.1.1 above, JANSEN guarantees the following emission levels at the stack:

The average of three (3) one-hour tests within an eight (8) hour test period for nitrogen oxides (NO_x) will not exceed 0.22 lb/MMBtu.

This NO_x guarantee is based on the premise that if the initial Phase 1 evaluation determines that an OFA system is not sufficient by itself to meet the guarantee, the use of flue gas recirculation, auxiliary fuel burner modifications, and/or changes in non-condensable gas incineration practices are acceptable options to enhance the NO_x emissions reduction. The commercial terms for the additional work would be mutually agreed upon by GP and JANSEN.

9.4 Performance Tests

JANSEN has guaranteed a certain performance level as per section 9.3. In order to determine the attainment of these guarantees, a performance test shall be performed. All performance tests shall be carried out on the boiler at the sole expense of G-P. These tests will be conducted within 60 days following start-up of the boiler, with the boiler in a clean state. G-P shall give JANSEN at least 15 days notice of the date or dates on which tests will be made. Test conditions will also require:

1. The general arrangement of equipment furnished by JANSEN, and the general design and arrangement of related equipment furnished by others shall not be less favorable than described in this Proposal. The equipment shall have been erected in accordance with JANSEN's plans and specifications, properly maintained and operated by G-P, and shall be in operating conditions satisfactory to both G-P and JANSEN.

2. The system for blending and feeding the fuel, and combustion control strategy shall be acceptable to both G-P and JANSEN. Further, G-P shall provide JANSEN with sufficient time to optimize the unit's operation over the load and fuel range prior to performance testing.

3. The existing boiler equipment and components shall be in good working condition. The heat absorbing surfaces shall be clean inside and out. The boiler casing, setting, and ducting shall be free from excessive air in-leakage. The auxiliary burners shall not have excessive air leakage into the furnace.

4. The treatment of feedwater and conditions of boiler water are beyond the control of JANSEN. Therefore, JANSEN shall not be held responsible for damage due to the presence of oil, grease, scale, or deposits on the internal surfaces of the equipment; or for damage resulting from foaming caused by chemical condition of the water; or for damage resulting from corrosion.

5. G-P shall satisfy JANSEN that all instrumentation used for the test is satisfactorily calibrated and accurate.

6. JANSEN representative shall have access to the records at all times

7. The heat and mass balance calculations for determining the grate fuel firing rate shall be consistent with the ASME Performance Test Code as agreed upon by both G-P and JANSEN.

8. Each performance guarantee acceptance test shall be executed for a time period not exceeding eight (8) hours.

9. The bark distribution system, bark refining/delivery systems and undergrate air system shall be operating to the satisfaction of GP and JANSEN.

10. G-P shall provide JANSEN with sufficient time to optimize the unit's operation at the firing conditions required by the performance guarantees prior to the actual guarantee acceptance test.

11. If G-P fails to perform the guarantee acceptance testing within 60 days after startup and the OFA system is operating as intended, or the conditions for testing stipulated herein are not met during testing, JANSEN will have met its obligations under these guarantees.

12. A complete copy of test data and results shall be furnished to JANSEN.

Other criteria for these tests, if any, shall be mutually agreed upon between JANSEN and G-P.

The equipment shall be considered as accepted if tests show that the guarantees have been fulfilled, or if G-P shall fail to have said equipment tested within the period mentioned.

9.5 Remedies For Failure To Pass Performance Test

Should the Performance Tests demonstrate that the equipment fails to conform as specified herein, and G-P notifies JANSEN, JANSEN shall at its sole expense, including all parts, labor, materials, on-site work and other expenses, correct the nonconformance to the equipment. Such corrective action may include, but shall not be limited to:

Repair, replacement, modification of the equipment, or additional design, equipment and construction services.

Upon completion of the corrective action, JANSEN shall notify G-P and additional tests shall be scheduled by G-P and conducted by G-P.

Any out-of-pocket expense to G-P for additional testing, except the expenses for G-P's mill operators and the raw materials required for the re-testing, shall be reimbursed by JANSEN.

JANSEN's total liability under this Section 9.5 is limited to the lesser of $77,000 or 10% of the final contract price, including any change orders.

ATTACHMENT IV

From: Bill Buckley [mailto:bbuckley@synterprise.com]
Sent: Thursday, December 22, 2005 11:18 PM
To: Orender, Robert H.
Subject: GP - PAL - Palatka Ecotube System Cost & Performance Estimates 12-22-05
Importance: High

Robert: Thank you so much again for your continuing interest in the Ecotube technology and its potential application in your Palatka, Florida operation. As you are probably aware, we have just commissioned our fifth project in the US with very positive results and have several other Ecotube projects on the drawing boards for calendar year 2006.

Following review of your information, it appears that a system consisting of two Ecotube assemblies would be appropriate for the Palatka boiler with a furnace dimension that's approximately 20 feet square. With that basis in mind, I have attached a "draft budgetary" purchase order for an "air only" system that will provide you with an estimated "turnkey" cost, a view of project division of responsibilities, Synterprise and GP obligations and possible milestone and payment schedules for a project with a target completion date of mid September 2006. We have just experienced a price increase in November from Ecomb but I feel confident that we can still meet or possibly beat this cost structure based on the results of an on-site engineering study.

The on-site engineering study is necessary to get an accurate sense of furnace temperature profiles which will help us determine the optimum elevation(s) for the actual Ecotube penetrations, obtain a more accurate estimate of project cost and performance benefits. Obviously, that location will determine the extent of structural steel support that might be required, obstacle clearance issues that must be addressed and things of that nature. In addition, the engineering study will generally consist of the following scope:

Synterprise Associate(s) will work closely with client personnel to:

- Schedule, coordinate and perform the required Engineering testing and site assessment activities
- Collect all plant operating, general equipment and electrical/mechanical design information necessary for Ecotube system installation
- Analyze all collected operating and design information
- Prepare Ecotube System Engineering Study Report

Some of the more specific value points of the Engineering Study process include:

A. Boiler performance measurements and variance analysis will provide the client, and Synterprise, with a better understanding of current boiler operational modes
    - Boiler flame pattern analysis of combustion conditions (Video analysis)
    - Furnace gas temperatures (Multiple tests with optical pyrometer)
    - Boiler operational data review and analysis –
      Air heater exit gas temp.
      Air heater air inlet temp.
      Relative humidity
      Excess air
      Cost of fuel $/ton
      Capacity factor
      Gross heat rate BTU/kwh
      O2 % at boiler exit
      Reheat spray flow lb/hr [if applicable]
    - Review of original boiler design acceptance test information and any additional performance analysis data that may be available
    - Boiler fuel analysis
      Fuel heating value btu/lb

Ultimate fuel analysis
% by Weight
- Ash
- Sulfur
- Hydrogen
- Carbon
- Nitrogen
- Oxygen
- Moisture

- Boiler ash analysis - unburned carbon

B. Provide projected operational performance improvement based on implementation of the Ecotube system will provide the client with boiler performance improvement potential
- Boiler performance assessment and projected improvement opportunity identification
- Predicted performance projection based on Synterprise proprietary spreadsheet model built using ASME boiler performance criteria (if applicable)

C. Provide an equipment configuration arrangement and a project plan
- Ecotube system project equipment configuration plan developed to obtain projected performance objectives
- Project plan developed to install the required Ecotube system lance assemblies and wall boxes as required
- Location of equipment, platforms (if required), and control equipment
- Air and source of cooling water requirements will be defined

Our clients (even those that have not elected to go forward with Ecotube projects) have found significant value in the Engineering Studies. Typical pricing for a study is $35,000 but I expect to have a team in the southeast region in mid January so, if you're interested, Synterprise will offer to perform the study at Palatka for $27,400 during that period which will keep the project on a fast track toward a possible completion date in the September 2006 timeframe.

From an emissions reduction performance perspective, it is realistic to assume that a minimum NOx reduction of 20% and a CO reduction of 80% can be achieved with an "air only" installation. Our actual results have ranged close to 40% for NOx reduction and 90% for CO reduction in certain applications.

If reagent is added to the Ecotube system for purposes of NOx reduction, a minimum NOx reduction of 60% should be attainable. Actual results have indicated that NOx reduction with reagent may approach 70-75% in certain cases. The "ballpark" added cost for a reagent storage and delivery system with controls integrated into the Ecotube system would be around $800 for a budgetary view.

As you know, the Ecotube technology also differentiates itself from many of the other "parasitic" emission reduction systems because Ecotube offers substantial combustion optimization value as well. Synterprise would be pleased to schedule a webcast or a direct visit to further discuss the Ecotube technology with GP personnel. In addition, we would be pleased to coordinate an actual site tour at either the Stratton or Ashland sites in Maine where Ecotube systems are in service on boilers with steam flows in the same region as your Palatka boiler.

Since you mentioned the potential replacement of your overfire air system at Palatka, let me advise you of another possible product that might be of interest. Synterprise now offers the Ecojet technology, which is a new proprietary "high energy", separated and "tunable" overfire air concept that has been developed by Synterprise during the last year (patent pending) to address issues that have been raised by a variety of clients. Basically, many clients are constrained by limited Capex, have serious combustion problems and have found that existing overfire air systems (both OEM and aftermarket offerings) are inadequate from a performance perspective. To address this need, we have successfully developed, completed production and conducted initial testing of the Ecojet system which now positions Synterprise to offer an integrated and phased strategy designed to give our clients the most appropriate system, yielding maximum benefits with lowest costs that best matches their particular business plans and objectives.

Again Robert, thank you very much for your continued interest in Synterprise's products and professional services and we'll look forward to your feedback. Please advise if you wish to proceed directly with an Engineering Study at Palatka and I'll get a proposal to you right away to initiate that effort.

Have a Joyous and Prosperous Holiday Season!

Very Best Regards,
Bill

William J. Buckley

Vice President Engineering and Construction

423 267 5363 Office
423 265 2350 Fax

www.synterprise.com

Innovative Solutions for
Operational Excellence

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

MEMORANDUM

To: Bruce Mitchell - Florida Department of Environmental Protection

From: Jim Little - EPA Region 4 (404-562-9118)

Subj: Georgia-Pacific Palatka Mill Draft Permit

Date: May 23, 2007

Thank you for sending the draft prevention of significant deterioration permit (PSD-FL-380) and accompanying technical evaluation and preliminary determination for a modification of the Georgia-Pacific Consumer Operations mill in Palatka, Florida. These documents are detailed and well written. We have only the following brief comments. The terms "we" and "our" in these comments refer to the Region 4 office of the U.S. Environmental Protection Agency (EPA).

1. Particulate Matter - $PM_{2.5}$ is a regulated new source review (NSR) pollutant that will be emitted from the modified emissions units. The only reference we see to $PM_{2.5}$ is in the best available control technology (BACT) section of the preliminary determination on page 7 where this statement appears: "Throughout the BACT analysis, the Department will use PM emissions as a surrogate to also reduce $PM_{2.5}$ and PM_{10} emissions." We first note that current EPA guidance is to use PM_{10} as a surrogate for $PM_{2.5}$. Second, we recommend that a statement about $PM_{2.5}$ be added to the final determination indicating that a surrogate approach was used for the air quality analysis as well as for the BACT analysis.

2. Compliance Averaging Period for Carbon Monoxide Emissions Limit - The compliance averaging period for the No. 4 Recovery Boiler carbon monoxide (CO) emissions limit is a 30-day rolling average. Our usual preference is (a) for at least one emissions limit for a given pollutant to be equal to the emissions rate used for air quality impact modeling purposes and (b) for the compliance averaging period associated with this limit to be generally consistent with the modeled averaging period(s). For CO, the modeled averaging periods were 1-hour and 8-hour averaging periods, not a 30-day period. In this case, however, we recognize that modeled CO concentrations are far below the reference values used to assess the modeling results and that the CO emissions limits for other emissions units affected by the project are short-term limits.

3. Netting Analysis - A netting analysis was performed for this project to demonstrate that several regulated NSR pollutants are not subject to PSD review. For an emissions decrease to be creditable in a PSD netting analysis, it must have "approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change [Florida Regulation 62-210.200(209)(f)3]. We understand that the Department took this requirement into account when excluding pollutants from PSD review based on netting.

Mitchell, Bruce

From: Little.James@epamail.epa.gov
Sent: Wednesday, May 23, 2007 1:44 PM
To: Mitchell, Bruce
Subject: Minor Items on G-P Palatka

Bruce -

Your preliminary determination and draft permit for Georgia-Pacific Palatka were excellent. I probably will send a couple of "official" comments in a separate e-mail message. While I finish those, here are some minor items for your use.

The table that starts at the bottom of page 5 of the preliminary determination and carries over to page 6 has footnote superscripts "1" and "4" in some of the column headings. However, I do not see any footnotes after the table where they would normally appear.

On page 13 of the draft permit under EXISTING APPLICABLE REGULATIONS, Item 2. (related to NSPS), I believe "NESHAP Subpart BB of 40 CFR 63" on the second line should be "NSPS Subpart BB of 40 CFR 60."

On page E-1 (Appendix E) of the draft permit, the last line of the table on that page has "VOC" with a footnote superscript "e." I see footnotes a. through d. (on page E-2), but I don't see footnote e.

Jim Little - EPA Region 4
(404) 562-9118

Mitchell, Bruce

From: Little.James@epamail.epa.gov
Sent: Wednesday, May 23, 2007 4:42 PM
To: Mitchell, Bruce
Subject: Comments on Georgia-Pacific Palatka Draft PSD Permit

Attachments: G-P Palatka - Region 4 Comments PSD-FL-380.doc

G-P Palatka -
Region 4 Comment..

Bruce -

Attached are Region 4's comments on the Georgia-Pacific Palatka mill draft PSD permit. Please call me if you have any questions.

Jim Little - U.S. EPA Region 4
(404) 562-9118

(See attached file: G-P Palatka - Region 4 Comments PSD-FL-380.doc)

E-mailed / received 5-16-07
Bruce

Georgia-Pacific

Palatka Pulp and Paper Operations
Consumer Products Division

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

May 7, 2007

Mr. Christopher L. Kirts, P.E.
District Air Program Administrator
State of Florida
Department of Environmental Protection
7825 Baymeadows Way Suite B200
Jacksonville, FL 32256-7590

RE: Draft Air Permit No. PSD-FL-380
Project No. 1070005-038-AC
Georgia-Pacific Consumer Products LLC – Palatka Mill
Modification of No. 5 Power Boiler, No. 4 Lime Kiln, No. 4 Recovery Boiler, and No. 4 Multiple Effect Evaporators

Dear Mr. Kirts:

Georgia-Pacific Consumer Products LLC (GP) has received the Florida Department of Environmental Protection's (DEP's) subject draft permit package dated April 13, 2007, and offers the following comments organized by document, section, and page number as appropriate:

Draft Permit

Section 3. Emissions Unit Specific Conditions.

Part C. No. 4 Lime Kiln.

Page 10 of 17, Condition 5 – Permitted Capacity:

Comment: The "material" that is limited to 41.5 tons/hr should be identified instead as "lime mud solids" for clarity.

Page 11 of 17, Condition 9 – PM Standard:

Comment: As with the previous comment, the standard would be more correctly stated in terms of: "lb per ton of lime mud solids processed".

Page 12 of 17, Condition 22 – Records and Reports, Kiln Process Rate

Comment: Revise to state that lime mud "solids" input shall be monitored and recorded, in order to be consistent with above comments.

Discussion: Lime Mud flow and density (% solids) to the lime kiln are monitored on a continuous basis. This data is averaged hourly and converted to tons per hour of lime mud solids. The proposed revisions will serve to more accurately describe the material input to the kiln and clarify that it is measured on a dry basis.

Page 12 of 17, Condition 20 – Fuel monitoring:

Comment and Discussion: This condition is a duplicate of condition 16, page 9, in section B. (No. 5 Power Boiler) and is not applicable to the lime kiln. This condition should be deleted from the lime kiln section. Lime kiln fuel records are addressed in condition 23 (page 12).

Part D, No. 4 Recovery Boiler

Pages 13 & 14 of 17, Condition 6 – Capacities, Fuels, and Restrictions:

Comment: Permitting Note at the end of this condition should be revised to note that the identified heating value of BLS is an average value. (suggested change: *The maximum heat input from firing BLS is 1345 MMBtu/hour based on the permitted capacity and an* ***average*** *heating value of 6410 Btu/lb of BLS.*)

Page 14, Condition 8 – CEMS:

Comment and Discussion: The condition requires installation of continuous monitors to determine the flue gas oxygen content and exhaust flow rate. The boiler currently has a stack O2 monitor that is used in conjunction with the TRS and SO2 CEMS. GP would utilize the existing stack O2 monitor to meet this requirement. Additionally, in lieu of the cost of installation and maintenance of a stack flow CEMS, GP would prefer to have the flexibility to develop a site-specific F-factor using stack test data and process information to establish a correlation between stack flow rate and other parameters, such as BLS firing rate, or to establish a maximum flow rate to be used for mass flow compliance calculations.

I, the undersigned, am the responsible official of the source for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and the data contained in this document are true, accurate, and complete.

If you have any questions regarding this correspondence, please contact Ron Reynolds at (386) 325-2001, ext. 4672.

Sincerely,

Keith Wahoske

Keith Wahoske
Vice President

cc: B. T. Champion, Atlanta
S. D. Matchett, Atlanta
W. Galler, Atlanta
T. Wyles, Atlanta
M.W. Curtis, Palatka
R.E. Reynolds, Palatka

Friday, Barbara

Permit Signed 5/29/07

From: Harvey, Mary
Sent: Tuesday, May 29, 2007 3:45 PM
To: 'Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC'; 'David A. Buff:'; Kirts, Christopher; 'Mr. Dee Morse, National Park Service'
Cc: Adams, Patty; Mitchell, Bruce; Gibson, Victoria
Subject: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC
Attachments: 1070005.038.AC.F_pdf.zip

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

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The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From:	Harvey, Mary
Sent:	Tuesday, May 29, 2007 3:46 PM
To:	'Ms. Kathleen Forney, EPA Region 4'; 'Mr. Jim Little, EPA Region 4'
Cc:	Adams, Patty; Mitchell, Bruce
Subject:	FW: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC
Attachments:	1070005 038- AC PSD FL 380 Final FD.PDF; Appendix - PSD-FL-380 - 1070005-038-AC-FINAL.PDF; Final Permit - PSD-FL-380 - ID #1070005-038-AC-FINAL.PDF; Signed Douments for Facility ID #1070005-038-FINAL.pdf

---

From: Harvey, Mary
Sent: Tuesday, May 29, 2007 3:45 PM
To: 'Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC'; 'David A. Buff:'; Kirts, Christopher; 'Mr. Dee Morse, National Park Service'
Cc: Adams, Patty; Mitchell, Bruce; Gibson, Victoria
Subject: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

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Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From:	Harvey, Mary
Sent:	Wednesday, May 30, 2007 9:10 AM
To:	Adams, Patty; Mitchell, Bruce
Subject:	FW: FW: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC
Attachments:	1070005 038- AC PSD FL 380 Final FD.PDF; Appendix - PSD-FL-380 - 1070005-038-AC-FINAL.PDF; Final Permit - PSD-FL-380 - ID #1070005-038-AC-FINAL.PDF; Signed Douments for Facility ID #1070005-038-FINAL.pdf

1070005 038- AC PSD FL 380 Fin... | Appendix - ;D-FL-380 - 107000 | Final Permit - PSD-FL-380 - ID... | Signed Douments for Facility I...

-----Original Message-----
From: Forney.Kathleen@epamail.epa.gov [mailto:Forney.Kathleen@epamail.epa.gov]
Sent: Wednesday, May 30, 2007 8:22 AM
To: Harvey, Mary
Subject: Re: FW: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

Thanks Mary

Katy R. Forney
Air Permits Section
EPA - Region 4
61 Forsyth St., SW
Atlanta, GA 30024

Phone: 404-562-9130
Fax: 404-562-9019

"Harvey, Mary"
<Mary.Harvey@dep.state.fl.us>

05/29/2007 03:46 PM

To
Kathleen Forney/R4/USEPA/US@EPA, James Little/R4/USEPA/US@EPA

cc
"Adams, Patty" <Patty.Adams@dep.state.fl.us>, "Mitchell, Bruce" <Bruce.Mitchell@dep.state.fl.us>

Subject
FW: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

From: Harvey, Mary
Sent: Tuesday, May 29, 2007 3:45 PM
To: 'Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC'; 'David A. Buff:'; Kirts, Christopher; 'Mr. Dee Morse, National Park Service'
Cc: Adams, Patty; Mitchell, Bruce; Gibson, Victoria
Subject: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

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Thank you,
DEP, Bureau of Air Regulation

(See attached file: 1070005 038- AC PSD FL 380 Final FD.PDF)(See attached file: Appendix - PSD-FL-380 - 1070005-038-AC-FINAL.PDF)(See attached file: Final Permit - PSD-FL-380 - ID #1070005-038-AC-FINAL.PDF) (See attached file: Signed Douments for Facility ID #1070005-038-FINAL.pdf)

Friday, Barbara

From: Harvey, Mary
Sent: Wednesday, May 30, 2007 9:15 AM
To: Adams, Patty; Mitchell, Bruce
Subject: FW: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

From: Curtis, Michael [mailto:MICHAEL.CURTIS@GAPAC.com]
Sent: Tuesday, May 29, 2007 4:58 PM
To: Harvey, Mary
Subject: Read: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

Your message

To: MICHAEL.CURTIS@GAPAC.com
Subject:

was read on 5/29/2007 4:58 PM.

Friday, Barbara

From: Harvey, Mary
Sent: Wednesday, May 30, 2007 9:09 AM
To: Mitchell, Bruce; Adams, Patty
Subject: FW: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

From: Kirts, Christopher
Sent: Wednesday, May 30, 2007 9:02 AM
To: Harvey, Mary
Subject: Read: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

Your message

To:	'Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC'; 'David A. Buff:'; Kirts, Christopher; 'Mr. Dee Morse, National Park Service'
Cc:	Adams, Patty; Mitchell, Bruce; Gibson, Victoria
Subject:	Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC
Sent:	5/29/2007 3:45 PM

was read on 5/30/2007 9:02 AM.

Friday, Barbara

From: Harvey, Mary
Sent: Tuesday, May 29, 2007 4:01 PM
To: Adams, Patty; Mitchell, Bruce
Subject: FW: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

From: Wahoske, Keith [mailto:KEITH.WAHOSKE@GAPAC.com]
Sent: Tuesday, May 29, 2007 3:59 PM
To: Harvey, Mary; Curtis, Michael; Aguilar, Mark J.; David A. Buff:; Kirts, Christopher; Mr. Dee Morse, National Park Service
Cc: Adams, Patty; Mitchell, Bruce; Gibson, Victoria
Subject: RE: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

Dear Ms. Harvey

We are in receipt of your Email.

Thank you

Keith Wahoske

-----Original Message-----
From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Tuesday, May 29, 2007 3:45 PM
To: Wahoske, Keith; Curtis, Michael; Aguilar, Mark J.; David A. Buff:; Kirts, Christopher; Mr. Dee Morse, National Park Service
Cc: Adams, Patty; Mitchell, Bruce; Gibson, Victoria
Subject: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

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Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From: Harvey, Mary
Sent: Tuesday, May 29, 2007 3:53 PM
To: Adams, Patty; Mitchell, Bruce
Subject: FW: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

From: Buff, Dave [mailto:DBuff@GOLDER.com]
Sent: Tuesday, May 29, 2007 3:52 PM
To: undisclosed-recipients
Subject: Read: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

Your message

To: DBuff@GOLDER.com
Subject:

was read on 5/29/2007 3:52 PM.

Friday, Barbara

From: Harvey, Mary
Sent: Tuesday, May 29, 2007 4:33 PM
To: Adams, Patty; Mitchell, Bruce
Subject: FW: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

Follow Up Flag: Follow up
Flag Status: Red

-----Original Message-----
From: Dee_Morse@nps.gov [mailto:Dee_Morse@nps.gov]
Sent: Tuesday, May 29, 2007 4:27 PM
To: Harvey, Mary
Subject: Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC

Return Receipt

Your document:	Georgia Pacific Consumer Operation, LLC - Facility #1070005-038-AC
was received by:	Dee Morse/DENVER/NPS
at:	05/29/2007 02:27:13 PM

PERMITTEE

Georgia-Pacific Consumer Operations LLC
Post Office Box 919
Palatka, Florida 32178-0919

Authorized Representative:
Mr. Keith Wahoske, Vice President

Air Permit No. 1070005-038-AC
PSD No. PSD-FL-380
Georgia-Pacific Palatka Mill
PSD Modification
SIC Nos. 2611 and 2621
Permit Expires: November 1, 2009

FACILITY AND LOCATION

Georgia-Pacific Consumer Operations LLC operates the Palatka Mill, which is a Kraft process pulp and paper mill located North of County Road 216 and West of U.S. Highway 17 in Palatka, Putnam County, Florida. The map coordinates are: UTM Zone 17; 434.0 km East; and, 3283.4 km North. This permit requires permanent shutdown of the No. 4 Power Boiler and authorizes modifications to the No. 5 Power Boiler, No. 4 Lime Kiln, No. 4 Recovery Boiler, and No. 4 multiple effect evaporator set.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Parts 60 and 63 of the Code of Federal Regulations (CFR). The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

CONTENTS

Joseph Kahn, Director
Division of Air Resource Management

5/29/2007
Effective Date

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Georgia-Pacific Consumer Operations LLC
P.O. Box 919
Palatka, Florida 32178-0919

Authorized Representative:
Mr. Keith Wahoske, Vice President – Palatka Operations

Air Permit No. PSD-FL-380
Project No. 1070005-038-AC
Palatka Mill
PSD Modification
Putnam County, Florida

Enclosed is the final PSD air construction permit, which authorizes the following major modifications: permanent shutdown of the No. 4 Power Boiler; conversion of the No. 5 Power Boiler to natural gas; replacement of the hot-end section and cooler tubes for the No. 4 Lime Kiln; extensive tube replacement and modification of the combustion air system (including the addition of a fourth level of overfire air) for the No. 4 Recovery Boiler; and, the addition of a crystallizer with associated storage/flash tank and modifications to the two concentrators associated with the No. 4 multiple effect evaporator set. The proposed work will be conducted at the existing Palatka Mill, which is located in Putnam County located North of CR 216 and West of US 17, in Palatka, Florida. As noted in the attached Final Determination, only minor changes and clarifications were made to the permit as drafted. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Permit and Final Determination) was sent by electronic mail with received receipt requested to the persons listed below.

Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC (keith.wahoske@gapac.com)
Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC (michael.curtis@gapac.com)
Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC (MJAGUILA@GAPAC.com)
Mr. David Buff, P.E., Golder Associates, Inc. (dbuff@golder.com)
Mr. Chris Kirts, Northeast District Office (chris.kirts@dep.state.fl.us)
Ms. Kathleen Forney, U.S. EPA, Region 4 (forney.kathleen@epa.gov)
Mr. Jim Little, U.S. EPA, Region 4 (little.james@epamail.epa.gov)
Mr. Dee Morse, National Park Service (Dee_Morse@nps.gov)

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 D Hanny (Clerk) 5/29/07 (Date)

Memorandum

Florida Department of Environmental Protection

TO: Joseph Kahn, Division of Air Resource Management

THRU: Trina Vielhauer, Bureau of Air Regulation
Jeff Koerner, Air Permitting North Section

FROM: Bruce Mitchell

DATE: May 25, 2007

SUBJECT: Air Permit No. PSD-FL-380
Project No. 1070005-038-AC
Georgia-Pacific Consumer Products LLC
Palatka Mill
Modifications to the No. 5 Power Boiler and the Nos. 4 Lime Kiln, Multiple Effect Evaporator Set and Recovery Boiler

The Final Permit for this project is attached for your approval and signature, which authorizes the following major modifications: permanent shutdown of the No. 4 Power Boiler; conversion of the No. 5 Power Boiler to natural gas; replacement of the hot-end section and cooler tubes for the No. 4 Lime Kiln; extensive tube replacement and modification of the combustion air system (including the addition of a fourth level of overfire air) for the No. 4 Recovery Boiler; and, the addition of a crystallizer with associated storage/flash tank and modifications to the two concentrators associated with the No. 4 multiple effect evaporator set. The equipment modifications will be made at the existing Palatka Mill located North of CR 216 and West of US 17, in Palatka, Putnam County, Florida. The project results in a major source air construction permit and is subject to PSD preconstruction review for PM/PM_{10}, NO_X, VOC and CO.

The Department distributed an "Intent to Issue Permit" package on April 13, 2007. The applicant published the "Public Notice of Intent to Issue" in the Palatka Daily News on April 24, 2007. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed. Timely comments were received from the applicant and are addressed in the Final Determination. The comments are considered to be minor.

I recommend your approval of the attached Final Permit for this project.

Attachments

PERMITTEE

Georgia-Pacific Consumer Products LLC
P.O. Box 919
Palatka, Florida 32178-0919

PERMITTING AUTHORITY

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

PROJECT

Air Permit No. PSD-FL-380
Project No. 1070005-038-AC
Palatka Mill

This project authorizes the following major modifications: permanent shutdown of the No. 4 Power Boiler; conversion of the No. 5 Power Boiler to natural gas; replacement of the hot-end section and cooler tubes for the No. 4 Lime Kiln; extensive tube replacement and modification of the combustion air system (including the addition of a fourth level of overfire air) for the No. 4 Recovery Boiler; and, the addition of a crystallizer with associated storage/flash tank and modifications to the two concentrators associated with the No. 4 multiple effect evaporator set. The equipment modifications will be made at the existing Palatka Mill located North of CR 216 and West of US 17, in Palatka, Putnam County, Florida. The project results in a major source air construction permit and is subject to PSD preconstruction review for PM/PM_{10}, NO_X, VOC and CO.

NOTICE AND PUBLICATION

The Department distributed an Intent to Issue Permit package on April 13, 2007. The applicant published the Public Notice of Intent to Issue in the Palatka Daily News on April 24, 2007. The Department received the proof of publication on April 30, 2007. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed.

COMMENTS

Applicant

On May 7, 2007, the Department received timely comments on the Draft Permit from the applicant. The following summarizes the comments and the Department's response.

1. In Specific Condition C.5. of the permit for the No. 4 Lime Kiln, it was requested that the term "material" be replaced with "lime mud solids" when describing the capacity.

   Response: The request better describes what is being processed in the No. 4 Lime Kiln. The Department agrees with the request and the change was made.

2. In Specific Condition C.9. of the permit for the No. 4 Lime Kiln, it was requested that the phrase "actual material" be replaced with "lime mud solids" in describing the particulate matter (PM) standard.

   Response: As stated above, the request is acceptable and the change was made.

3. In Specific Condition C.22. (renumbered to C.21.) of the permit for the No. 4 Lime Kiln, it was requested that "lime mud solids" instead of "lime mud" be monitored and recorded to be consistent with the previous requests.

   Response: As stated above, the request is acceptable and the change was made.

4. In the permit, the fuel specifications stated in Specific Condition C.20. is applicable to the No. 5 Power Boiler, not the No. 4 Lime Kiln, and is appropriately stated in Specific Condition B.16. for the No. 5 Power Boiler. The fuel specifications for the No. 4 Lime Kiln are stated in Specific Condition C.23. It is requested that Specific Condition C.20. be deleted.

   Response: The Department agrees with the request and Specific Condition C.20. was deleted and the subsequent Specific Conditions were renumbered.

5. In Specific Condition D.6. (renumbered to D.5.) of the permit for the No. 4 Recovery Boiler, specifically in the "Permitting Note", it is requested to insert the word "average" to describe the heating value of black liquor solids.

   Response: The Department agrees with the request and the change was made.

6. In Specific Condition D.8. (renumbered to D.7.) of the permit for the No. 4 Recovery Boiler, it is requested to allow the opportunity to develop an F-factor in lieu of installing a continuous monitor for the exhaust flow rate.

   Response: The Department agrees with the request and the following text was added:

   As an alternative to a continuous flow monitor, the permittee may develop a site specific F-factor for BLS in accordance with the following procedure:

   a. Submit a test protocol for approval to the Bureau of Air Regulation for developing a site specific F-factor for BLS.

   b. Upon written approval from the Bureau of Air Regulation, conduct the testing program in accordance with the protocol.

   c. Develop a site-specific F-factor for BLS based on the testing program and operational data.

   d. Submit a report on the testing program to the Bureau of Air Regulation summarizing: the tests conducted, explanations of any deviations from the test protocol, the data collected, the proposed site-specific F-factor for BLS, and an evaluation of the estimated flow rates compared to the actual measured flow rates.

   e. Submit a request for approval to the Bureau of Air Regulation to use the proposed site-specific F-factor for BLS.

   f. Upon written approval by the Bureau of Air Regulation, the permittee may begin using the site-specific F-factor for BLS to determine the exhaust flow rate. If the Bureau of Air Regulation does not approve the site-specific F-factor for BLS, the permittee shall install a continuous flow monitor.

U.S. EPA Region 4 Office

On May 23, 2007, the Department received comments from Mr. Jim Little of U.S. EPA Region 4 Office. The following summarizes the comments and the Department's response.

1. In Specific Condition D.2. of the permit for the No. 4 Recovery Boiler and under "Existing Applicable Regulations", it is stated that the emissions unit is subject to the requirements specified in "NESHAP Subpart BB of 40 CFR 63" and probably should read as "NSPS Subpart BB of 40 CFR 60".

   Response: The Department agrees that this is the proper reference. However, after further review, the No. 4 Recovery Boiler was built in 1976 and has not been modified since. Therefore, it is not subject to the provisions of the NSPS. The text was deleted and the subsequent specific conditions were renumbered.

2. Since the current EPA guidance is to use PM_{10} as a surrogate for $PM_{2.5}$ and the Department used PM as a surrogate for PM_{10} and $PM_{2.5}$ in its BACT analysis discussions, it is recommended that the permitting authority address this issue in the Final Determination.

   Response: Appendix E (Final BACT Determinations and Emissions Summary) of the Final Permit includes the following statement, "Throughout this appendix particulate matter emissions are referred to as PM emissions, which serve as a surrogate for regulating $PM_{2.5}$ and PM_{10} emissions." This surrogate approach was also used in the air quality analysis.

3. EPA's preference for establishing an emission limit and averaging period for a pollutant is to use the emissions rate used for the air quality impact modeling (if more than one exists, then use at least one). For CO, the modeled averaging periods were 1-hour and 8-hour. However, EPA recognizes that the modeled CO concentrations are far below the reference values used to assess the modeling results and that the CO limits for other emissions units affected by the project are short-term limits.

   Response: This project represents the first CO monitor required for a recovery boiler. As indicated in the Air Quality Analysis, the maximum predicted CO impacts were only 4% and 13% of the Class II significant impact levels for the 1-hour and 8-hour averaging periods. In addition to ensuring continuous compliance, the purpose of the CEMS was to obtain actual data for use in evaluating the relationship between CO and NOx with the modified overfire air system. The 30-day averaging period provides operational flexibility and reasonable assurance of compliance with the ambient air quality standards.

4. In a PSD netting analysis, a creditable emissions decrease must have "approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change". The EPA concurs that the PSD netting analysis was done this way for this project.

   Response: The Department did consider the qualitative significance of the emissions increases and decreases.

CONCLUSION

The final action of the Department is to issue the permit with the minor revisions, corrections, and clarifications as described above.

4.1 Effects on other Emission Units

Due to the proposed modification to the B SAP and A and B PAPs, several other emission units at the Plant City facility may potentially be affected (i.e., increased production rates or actual emission rates). The following sections describe the other emission units at CF to be affected by the proposed modifications.

4.1.1 Molten Sulfur Handling System

There will be no physical modifications to the Molten Sulfur Storage and Handling System as part of this project. CF recently received a PSD construction permit (0570009-019-AC/PSD-FL-339) to increase the maximum potential molten sulfur throughput from 930,750 TPY to 965,388 TPY to facilitate an H_2SO_4 production increase at the C and D SAPs. The maximum rate of 965,388 TPY for the Molten Sulfur Handling System is considered to be adequate to support the potential increase in the production rate for the B SAP as well.

Since the maximum permitted molten sulfur throughput rate will not be increasing, and since the Molten Sulfur Handling System has recently undergone PSD review in a separate application with the maximum rate, the Molten Sulfur Handling System is not considered to be affected by the proposed project.

4.1.2 A, C and D Sulfuric Acid Plants

The increased production of the PAPs will be facilitated by the installation of additional reactor flash cooling equipment, increased evaporation capacity equipment, and increased amount of H_2SO_4 produced in the B SAP. Therefore, the H_2SO_4 production at the A, C and D SAPs will not be affected due to the proposed project. CFI is also proposing a 24-hour average SO_2 emission rate of 250 lb/hr for the A SAP (EU ID 002), which currently has a 3-hour average SO_2 emission rate of 303.3 lb/hr. The lower emissions rate was used to demonstrate compliance with the 24-hour ambient air quality standard for SO_2 in the modeling analysis.

Currently, most of the H_2SO_4 required for the P_2O_5 production is manufactured onsite. The balance is imported from outside. However, since the potential H_2SO_4 production at the B SAP will be increasing as part of the proposed project, CF will be importing less H_2SO_4 in the future. Trucks and railcars are used to import purchased H_2SO_4. Therefore, fewer trucks will be driven onsite to import purchased H_2SO_4 in the future.

4.1.3 MAP/DAP Plants

The facility is permitted to operate four MAP/DAP plants: A, X, Y and Z. The A MAP/DAP plant has been in cold shutdown for the past five years and was operational for only a few days in October 2005 for a compliance test. The Plant City complex plans to keep the A MAP/DAP plant in cold shutdown and start it only in case of emergency need. Therefore, there will be no change in operation of the A MAP/DAP plant due to the proposed project.

At the MAP/DAP plants, phosphoric acid is reacted with ammonia to produce fertilizer. Due to the increased production of phosphoric acid, the actual production of fertilizer is also expected to increase. However, the permitted capacities of the A, X, Y and Z MAP/DAP plants will not change.

CFI is also proposing more stringent short term limits for PM for the A and Z MAP/DAP plants. The lower emission rate was used to demonstrate compliance with the ambient air quality standard for PM in

FACILITY DESCRIPTION

Georgia-Pacific operates an existing paper and pulp mill in Palatka, Florida using the Kraft sulfate process. In the Kraft process, the digesting liquor (white liquor) is a solution of sodium hydroxide and sodium sulfide that is mixed with wood chips and cooked under pressure. The spent liquor, known as weak black liquor, is concentrated and sodium sulfate is added to make up for chemical losses. The black liquor solids (BLS) are burned in the recovery furnace to produce a smelt of sodium carbonate and sodium sulfide. The smelt is dissolved in water to form green liquor to which quicklime (calcium oxide) is added to convert the sodium carbonate back to sodium hydroxide, which reconstitutes the cooking liquor. The spent lime cake (calcium carbonate) is recalcined in a rotary lime kiln to produce quicklime, which is used to convert the green liquor to cooking liquor. Other steam and energy needs are met by the power boilers, which burn a variety of fuels including fuel oil and natural gas.

REGULATORY CLASSIFICATION

- The facility is a major source of hazardous air pollutants (HAP).
- The facility operates no units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution.
- The facility is a major stationary source subject to the Prevention of Significant Deterioration (PSD) of Air Quality.

PROJECT DESCRIPTION

This permit authorizes the following major modifications: permanent shutdown of the No. 4 Power Boiler; conversion of the No. 5 Power Boiler to natural gas; replacement of the hot-end section and cooler tubes for the No. 4 Lime Kiln; extensive tube replacement and modification of the combustion air system (including the addition of a fourth level of overfire air) for the No. 4 Recovery Boiler; and the addition of a crystallizer with associated storage/flash tank and modifications to the two concentrators associated with the No. 4 multiple effect evaporator set. This permit affects the following emissions units.

ID	Emission Unit Description
014	No. 4 Power Boiler
015	No. 5 Power Boiler
016	No. 4 Combination Boiler
017	No. 4 Lime Kiln
018	No. 4 Recovery Boiler
037	Noncondensable Gas System including the No. 4 Multiple Effect Evaporator (MEE) Set

The permittee conducted a PSD netting analysis based on contemporaneous emissions increases and decreases to avoid PSD preconstruction review for sulfur dioxide (SO_2), sulfuric acid mist (SAM), and total reduced sulfur (TRS). The project is subject to PSD preconstruction review for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM), and volatile organic compounds (VOC). For this permit, the Department determined the Best Available Control Technology (BACT) for the following units: the No. 5 Power Boiler (CO and VOC); the No. 4 Lime Kiln (CO, NO_X, PM, and VOC); and the No. 4 Recovery Boiler (CO, NO_X, PM, and VOC). The No. 4 Combination Boiler is currently under PSD preconstruction review in Project No. 1070005-045-AC for CO, NO_X, PM, and VOC. Throughout this permit, particulate matter emissions are referred to as PM emissions, which serve as a surrogate for regulating $PM_{2.5}$ and PM_{10} emissions.

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action: the permit application and additional information received to make it complete; the draft permit package including the Department's Technical Evaluation and Preliminary Determination; publication and comments; the Department's Final Determination; previous air construction permits; and the current Title V air operation permit.

1. Permitting Authority: The Permitting Authority for this project is the Bureau of Air Regulation in the Division of Air Resource Management of the Department. The mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The phone number is 850/488-0114.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's Northeast District Office. The mailing address is 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida, 32256. The phone number is 904/807-3300.

3. Appendices: The following Appendices are attached as part of this permit:

   a. Appendix A. Citation Formats

   b. Appendix B. General Conditions

   c. Appendix C. Common Conditions

   d. Appendix D. Standard Testing Requirements

   e. Appendix E. Standard Continuous Monitoring Requirements

   f. Appendix F. Final BACT Determinations and Emissions Summary

   g. Appendix G. On-Specification Used Oil Requirements

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.

5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

6. Modifications: No emissions unit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Source Obligation:

   (a) Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit.

   (b) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

(c) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

[Rule 62-212.400(12), F.A.C.]

8. Title V Permit: This permit authorizes specific modifications and/or new construction on the affected emissions units as well as initial operation to determine compliance with conditions of this permit. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after completing the required work and commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Air Resource Section of the Department's Northeast District Office. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

9. Previous Air Construction Permits: This permit supplements all previous permits issued for the affected emissions units. The conditions of this permit satisfy the applicable requirements for the emissions increases related to the project. These conditions supersede corresponding similar conditions specified in previous air construction permits. However, if not specifically regulated by this permit, other standards and permit requirements from previous air construction permits remain valid. The affected emissions units remain subject to all applicable standards and regulations as regulated by the Title V air operation permit. [Rules 62-212.300 and 62-212.400 (BACT), F.A.C.]

This subsection of the permit addresses the following emissions units.

ID	Emission Unit Description
014	No. 4 Power Boiler
016	No. 4 Combination Boiler

{Permitting Note: In accordance with Rule 62-212.400 (PSD), F.A.C., the permittee conducted a PSD netting analysis that used contemporaneous emissions decreases from the permanent shutdown of the No. 4 Power Boiler to avoid PSD preconstruction review for SO_2, SAM, and TRS.}

PERFORMANCE RESTRICTIONS

1. Shutdown: The No. 4 Power Boiler is currently not in operation. As part of this project, the permittee shall permanently shutdown the No. 4 Power Boiler. Within 90 days of issuance of this permit, the permittee shall provide written notice of the permanent shutdown of this unit. [Rules 62-4.070(3) and 62-212.400(12), F.A.C.]
2. PSD Review: The permittee plans to modify the No. 4 Combination Boiler. Although a review is being conducted under Project No. 1070005-045-AC, emissions increases from this unit were included in the PSD netting analysis. That project is also subject to PSD preconstruction review for CO, NO_X, PM, and VOC emissions. [Rule 62-212.400 (PSD), F.A.C.]
3. Oil Firing – No. 4 Combination Boiler: The maximum sulfur content of oil is 2.35% by weight. No more than 5,100,000 gallons of oil shall be fired during any consecutive 12 months. The permittee shall keep records on a monthly basis to ensure compliance with the oil firing restriction. *{Permitting Note: This limits oil firing to an annual capacity factor of approximately 21% of the total maximum heat input rate to the unit.}*

B. No. 5 Power Boiler

This subsection of the permit addresses the following emissions unit.

ID	Emission Unit Description
015	**No. 5 Power Boiler**: This unit fires natural gas to produce steam and power for use at the mill. The permitted capacity is 568.9 MMBtu per hour of heat input to produce approximately 445,200 lb/hour of steam. CO, NO_X and VOC emissions are controlled by the burner design and efficient combustion of natural gas, which also minimizes PM/PM_{10}, SAM and SO_2 emissions. At permitted capacity, the exhaust gas flow rate is 135,400 dscfm at 10% oxygen with an exit temperature of 500° F. Exhaust gases exit a stack that is 9.0 feet in diameter and 156.5 feet tall.

{Permitting Note: In accordance with Rule 62-212.400 (PSD), F.A.C., the above emission unit is subject to BACT determinations for CO and VOC emissions, which are presented in Appendix E of this permit.}

EXISTING APPLICABLE REQUIREMENTS

1. State Rule for Kraft Pulp Mills: The No. 5 Power Boiler is subject to the applicable requirements of Rule 62-296.404, F.A.C. for Kraft Pulp Mills.
2. State Rule for Large Boilers: The No. 5 Power Boiler is subject to the applicable requirements of Rule 62-296.405, F.A.C. for Fossil Fuel Steam Generators with More than 250 MMBtu per hour of Heat Input.
3. NESHAP Subpart S for Kraft Pulp Mills: The No. 5 Power Boiler is subject to the applicable MACT requirements in NESHAP Subpart S in 40 CFR 63.
4. NESHAP Subpart DDDDD for Industrial Boilers: The No. 5 Power Boiler is subject to the applicable requirements for existing units specified in NESHAP Subpart DDDDD of 40 CFR 63 for Industrial, Commercial, and Institutional Boilers and Process Heaters.
5. PCP Exemption: This current permitting action does not affect the previous authorization of Permit No. 1070005-024-AC issued on July 2, 2004 for destroying DNCGs issued as a Pollution Control Project (PCP) pursuant to Rule 62-212.400(2)(a)2.b, F.A.C. That permit specified the strategy for complying with the applicable requirements of the MACT standards in NESHAP Subpart S in 40 CFR 63. That permit authorizes the No. 5 Power Boiler to destroy dilute non-condensable gases (DNCGs) from the high-volume, low-concentration (HVLC) system, which include emissions from brown stock washers, pressure knotters, the bleach plant pre-washer, the oxygen delignification system, and softwood/hardwood high density storage tanks. The DNCGs are introduced with the primary fuel, directed into the flame zone, or added with the combustion air. Optionally, the DNCGs may also be directed to the No. 4 Combination Boiler, which shares common permit conditions with the No. 5 Power Boiler. Permit No. 1070005-024-AC limits SO_2 emissions to 82.6 lb/hour and 236.3 tons per year from the destruction of DNCGs in any combination of the No. 4 Combination Boiler and the No. 5 Power Boiler. [Permit No. 1070005-024-AC; Rule 62-212.400 (PSD), F.A.C.]

MODIFICATIONS AND CAPACITIES

6. Natural Gas Conversion: The permittee shall convert the No. 5 Power Boiler to a natural gas-fired boiler. The permittee shall remove the oil burners and install natural gas burners that will achieve the emissions standards and capacities specified in this permit. If necessary to achieve the NO_X standard, the permittee is authorized to install a flue gas recirculation system consisting of the necessary fans, ductwork, and dampers. The conversion to natural gas shall be completed by April 1, 2008. Once converted to natural gas, the existing electrostatic precipitator may be removed from the No. 5 Power Boiler. It may be used as additional fields for controlling PM emissions from the No. 4 Combination Boiler. [Application No. 1070005-038-AC; Rule 62-212.400 (PSD), F.A.C.]

7. Authorized Fuels: The No. 5 Power Boiler shall be converted to fire pipeline natural gas as the sole fuel. After completing the project, the firing of oil is prohibited. As a control device, the No. 5 Power Boiler is authorized to destroy dilute non-condensable gases (DNCGs) from the high-volume, low-concentration (HVLC) system *{Permitting Note: The No. 5 Power Boiler currently fires oil with a maximum sulfur content of 2.35% by weight. After conversion to natural gas, potential annual SO_2 emissions will be less than 2 tons per year and potential SAM and TRS emissions will be negligible.}* [Application No. 1070005-038-AC; Rule 62-212.400 (PSD), F.A.C.]

8. Permitted Capacity: After converting to natural gas, the permitted capacity of the No. 5 Power Boiler shall be 568.9 MMBtu of heat input per hour based on a 24-hour average. At this heat input rate, the unit will produce approximately 445,200 lb/hour of steam based on a 24-hour average. Hours of operation are not restricted (8760 hours/year). [Application No. 1070005-038-AC; Rules 62-210.200 (PTE) and 62-212.400 (PSD), F.A.C.]

EMISSIONS AND PERFORMANCE STANDARDS

9. CO Standard: As determined by EPA Method 10, CO emissions shall not exceed 0.185 lb per MMBtu of heat input and 105.2 lb/hour based on the average of three test runs. The CO standard serves as a surrogate standard for minimizing VOC emissions as a result of the efficient combustion of natural gas. *{Permitting Note: VOC emissions are expected to be less than 14 tons per year from firing natural gas.}* [Rule 62-212.400 (BACT), F.A.C.]

10. NO_X Standard: As determined by EPA Method 7E, NO_X emissions shall not exceed 0.125 lb/MMBtu of heat input and 71.1 lb/hour based on the average of three test runs. [Rules 62-4.070(3) and 62-212.400(12), F.A.C.]

COMPLIANCE MONITORING AND TESTING

11. Standard Testing Requirements: All required emissions tests shall be conducted in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. [Rules 62-204.800 and 62-297.100, F.A.C.; and 40 CFR 60, Appendix A]

12. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. [Rule 62-297.310(7)(a)9, F.A.C.]

13. Test Methods: When required, tests shall be performed in accordance with the following methods.

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Note: The method shall be based on a continuous sampling train.}
19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)

Tests shall also be conducted in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

14. Initial Stack Tests: In accordance with the specified test methods, the No. 5 Power Boiler shall be tested to demonstrate compliance with the emissions standards for CO and NO_X. Initial stack tests for these pollutants shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial startup on natural gas. All initial tests shall be conducted with the emissions unit operating at 90% to 100% of the permitted capacity; otherwise, this permit shall be modified to reflect the true maximum capacity as constructed. The Department may require the permittee to repeat some or all of the initial stack tests after major replacement or major repair of emissions-related equipment. [Rules 62-4.070(3), 62-212.400(PSD) and 62-297.310(7), F.A.C.]

15. Annual Stack Tests: During each federal fiscal year (October 1st to September 30th), the No. 5 Power Boiler shall be tested to demonstrate compliance with the emission standards for CO and NO_X. Testing of emissions shall be conducted with the emissions unit operating at 90% to 100% of the permitted capacity. If it is impractical to test within this range, the emissions unit may be tested at less than 90% of the maximum permitted capacity. In this case, subsequent emissions unit operation is limited to 110% of the tested 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. *{Permitting Note: Additional tests may be required by other applicable requirements.}* [Rules 62-4.070(3), 62-212.400(PSD) and 62-297.310(7), F.A.C.]

16. Fuel Monitoring: The permittee shall install equipment to continuously monitor the flow rates of natural gas and DNCGs to the No. 5 Power Boiler. This may consist of fuel flow meters with integrators to monitor each flow rate. [Rules 62-4.070(3) and 62-212.400(12), F.A.C.]

RECORDS AND REPORTS

17. Test Reports: For each required test, the permittee shall file a report with the Compliance Authority on the results of each required test in accordance with the requirements of Rule 62-297.310(8), F.A.C.

18. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the No. 5 Power Boiler on a daily average basis considering the number of hours of operation during each day. This shall be achieved through monitoring daily rates of consumption and heat content of natural gas. The information shall be documented and recorded for each day of operation. Records shall be made available to the Compliance Authority upon request. [Rule 62-4.070(3), F.A.C.]

This subsection of the permit addresses the following emissions unit.

ID	Emission Unit Description
017	**No. 4 Lime Kiln**: This unit recalcines the spent lime cake (calcium carbonate) to produce the quicklime (calcium oxide), which is used to convert the green liquor to cooking liquor. The kiln fires residual fuel oil and has a maximum processing rate of 41.5 tons of material per hour based on a 24-hour average. Particulate matter emissions are controlled by a cyclonic dust collector followed by a wet venturi scrubber. TRS emissions, scrubber pressure drop, and scrubber flow rate are continuously monitored and recorded. At permitted capacity, the exhaust gas flow rate is 54,200 dscfm at 10% oxygen with an exit temperature of 164° F. Exhaust gases exit a stack that is 4.4 feet in diameter and 131 feet tall.

{Permitting Note: In accordance with Rule 62-212.400 (PSD), F.A.C., the above emission unit is subject to BACT determinations for CO and VOC emissions, which are presented in Appendix E of this permit.}

EXISTING APPLICABLE REQUIREMENTS

1. State Rule for Kraft Pulp Mills: The No. 4 Lime Kiln remains subject to the applicable requirements of Rule 62-296.404, F.A.C. for Kraft Pulp Mills.
2. NESHAP Subpart MM for Kraft Pulp Mills: The No. 4 Lime Kiln remains subject to the applicable MACT requirements in NESHAP Subpart S in 40 CFR 63.
3. PSD Permit: Unless otherwise specified by condition in this permit, the No. 4 Lime Kiln remains subject to the applicable requirements of Permit No. PSD-FL-171.

MODIFICATIONS AND CAPACITIES

4. Kiln Modification: For the No. 4 Lime Kiln, the permittee is authorized to replace approximately 62 feet of the hot-end kiln shell and all 10 coolers located in this section. The new coolers will be mounted with an improved bracket design to prevent stress cracks underneath the coolers. [Rule 62-210.300(1), F.A.C.]
5. Permitted Capacity: The maximum processing rate of the No. 4 Lime Kiln is 41.5 tons of lime mud solids per hour based on a 24-hour average. This corresponds to a maximum production rate of 19.4 tons per hour of quicklime. There is no restriction on the hours of operation (8760 hours/year). At permitted capacity, the maximum flue gas flow rate is 54,200 dscfm @ 10% oxygen. The lime kiln typically operates at flue gas oxygen contents in the range of 4% to 6% by volume. [Application No. 1070005-038-AC; Rule 62-210.200 (PTE), F.A.C.]
6. Authorized Fuels: The No. 4 Lime Kiln is authorized to fire residual fuel oil with a maximum fuel sulfur content of 2.35% by weight as the primary fuel. On-specification used oil meeting the requirements in Appendix G of this permit may be blended with the residual oil and fired at a rate of no more than 10% of the fuel consumed. Natural gas is authorized as a startup and alternate fuel. The maximum heat input rate is 140 MMBtu per hour when firing a maximum of 933 gallons per hour of residual oil with a heating value of 150,000 Btu per gallon. No more than 8,173,000 gallons of oil shall be fired during any consecutive 12 months. [Application No. 1070005-038-AC; Rule 62-210.200 (PTE), F.A.C.]

EMISSIONS AND PERFORMANCE STANDARDS

7. CO Standard: As determined by EPA Method 10, CO emissions shall not exceed 69.0 ppmvd at 10% O_2 and 16.3 lb/hour based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

8. NOx Standard: As determined by EPA Method 7E, NO_X emissions shall not exceed 140.0 ppmvd at 10% O_2 and 54.2 lb/hour based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

9. PM Standard: As determined by EPA Method 5, PM emissions from the No. 4 Lime Kiln shall not exceed 0.55 lb per ton of lime mud solids processed and 22.9 lb/hour based on the average of three test runs. *{Permitting Note: The venturi scrubber causes a wet plume, which interferes with the determination of opacity. The scrubber monitoring provisions will be used to ensure proper operation of the venturi scrubber.}* [Rule 62-212.400 (BACT), F.A.C.]

10. SO_2 Standard: As determined by EPA Method 8, SO_2 emissions shall not exceed 16.9 ppmvd at 10% O_2 and 9.1 lb/hour based on the average of three test runs. [Rule 62-212.400(12), F.A.C.]

11. TRS Standard: As determined by the existing CEMS, TRS emissions shall not exceed 25.1 tons per year based on a 12-month rolling CEMS total. [Rule 62-212.400(12), F.A.C.]

12. VOC Standard: As determined by EPA Method 25A, VOC emissions from the lime kiln shall not exceed 70.0 ppmvd at 10% O_2 and 9.4 lb/hour (total hydrocarbons determined as methane) based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

COMPLIANCE MONITORING AND TESTING

13. Standard Testing Requirements: All required emissions tests shall be conducted in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. [Rules 62-204.800 and 62-297.100, F.A.C.; and 40 CFR 60, Appendix A]

14. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. [Rule 62-297.310(7)(a)9, F.A.C.]

15. Test Methods: When required, tests shall be performed in accordance with the following methods.

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5	Determination of Particulate Matter from Stationary Sources
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Note: The method shall be based on a continuous sampling train.}
19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)

Tests shall also be conducted in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

16. Initial Compliance Tests: The No. 4 Lime Kiln shall be tested to demonstrate initial compliance with the emissions standards specified for CO, NO_X, PM, SO_2, and VOC. The initial tests shall be conducted within 60 days after completing the kiln modification and achieving permitted capacity, but not later than 180 days after initial operation of the unit. [Rules 62-297.310(7)(a)1 and 62-212.400 (BACT), F.A.C.]

17. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the No. 4 Lime Kiln shall be tested to demonstrate compliance with the emissions standards for CO, NO_X, PM, SO_2, and VOC. If consecutive annual tests for CO or VOC emissions show compliance at 50% of the standard or less, the test frequency for that pollutant is reduced to testing prior to renewal of the operation permit. Annual testing shall resume for any subsequent failure to demonstrate compliance at renewal. [Rules 62-297.310(7)(a)4 and 62-212.400 (BACT), F.A.C.]

18. Tests Prior to Renewal: Within the 12-month period prior to expiration of the operation permit, the No. 4 Lime Kiln shall be tested to demonstrate compliance with the emission standards for CO, NO_X, PM, SO_2, and VOC. [Rules 62-297.310(7)(a)3 and 62-212.400 (BACT), F.A.C.]

19. Scrubber Monitoring: The permittee shall install, operate, and maintain equipment to continuously monitor and record the venturi scrubber pressure drop and flow rate. In accordance with the monitoring requirements specified in NESHAP Subpart MM, minimum operating levels shall be determined for these parameters; however, the operating levels shall be selected to ensure compliance with the BACT standard specified in this permit. If monitors show operation below the minimum operating levels, the permittee shall take appropriate corrective actions to regain proper operation of the control system. [Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

RECORDS AND REPORTS

20. Scrubber Records: The permittee shall continuously monitor and record the venturi scrubber pressure drop and flow rate in accordance with the monitoring requirements specified in NESHAP Subpart MM. The permittee shall document and record corrective actions taken to regain proper operation of the control system if operation falls below the minimum operating levels. [Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

21. Kiln Process Rate: The permittee shall monitor and record the total lime mud solids input to the No. 4 Lime Kiln on an hourly basis and record the daily average in tons per hour. [Rule 62-4.070(3), F.A.C.]

22. Fuel Records: On a monthly basis, the permittee shall document the amount of oil fired during each calendar month and the 12-month rolling total. [Rule 62-4.070(3), F.A.C.]

23. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. For each test run, the report shall also indicate the lime kiln processing rate, the fuel firing rate, the venturi scrubber pressure differential, and the venturi scrubber flow rate. [Rule 62-297.310(8), F.A.C.]

This subsection of the permit addresses the following emissions unit.

ID	Emission Unit Description
018	**No. 4 Recovery Boiler**: This unit fires black liquor solids (BLS) as the primary fuel to facilitate the recovery of the cooking liquor. Residual fuel oil is fired as a startup and supplemental fuel. The maximum steam production rate is 789,000 lb/hour (24-hour average) for steam conditions of 850° F to 900° F at 1250 psi. Particulate matter emissions are controlled by an electrostatic precipitator (ESP) with automatic voltage control, 2-chambers, and 6 electric fields per chamber. Total reduced sulfur emissions are reduced by the low-odor design. NO_X emissions are controlled by a four-level overfire air system. CO and VOC emissions are controlled by good combustion design and operating practices. CO, NO_X, SO_2, TRS, and opacity are continuously monitored and recorded. At permitted capacity, the exhaust gas flow rate is 294,000 dscfm at 8% oxygen with an exit temperature of 400° F. Exhaust gases exit a stack that is 12 feet in diameter and 230 feet tall.

{Permitting Note: In accordance with Rule 62-212.400 (PSD), F.A.C., the above emission unit is subject to BACT determinations for CO, NO_X, PM, and VOC emissions, which are presented in Appendix E of this permit.}

EXISTING APPLICABLE REGULATIONS

1. State Rule for Kraft Pulp Mills: The No. 4 Recovery Boiler is subject to the applicable requirements for existing units in Rule 62-296.404, F.A.C. These standards are specified in the Title V air operation permit.
2. NESHAP Subpart MM: The No. 4 Recovery Boiler is subject to the applicable requirements specified in NESHAP Subpart MM of 40 CFR 63 for recovery combustion sources at Kraft pulp mills. These standards are specified in the Title V air operation permit.
3. PSD Permits: Unless otherwise specified by condition in this permit, the No. 4 Recovery Boiler remains subject to the applicable requirements of Permit Nos. PSD-FL-171 and PSD-FL-226.

MODIFICATIONS AND CAPACITIES

4. No. 4 Recovery Boiler Modifications: The permittee is authorized to perform the following modifications to the No. 4 Recovery Boiler in accordance with the following preliminary schedule: modify the combustion air system; add a fourth level of overfire air (quaternary air); and replace tubes in the superheater, economizer, and walls of the recovery boiler. These changes will not increase the existing permitted capacity of the recovery boiler or the pulp mill. The preliminary schedule is to begin construction in May of 2007. [Application No. 1010005-038-AC; Rules 62-212.300 and 62-212.400 (PSD), F.A.C.]
5. Capacities, Fuels and Restrictions: The No. 4 Recovery Boiler fires BLS as the primary fuel for the recovery process as well as the following fuels: natural gas as a startup and supplemental fuel; residual fuel oil with a maximum sulfur content of 2.35% by weight; and limited amounts of on-specification used oil meeting the requirements in Appendix G of this permit. The permitted capacity is 210,000 lb/hour of BLS based on a 24-hour average. The maximum consumption of oil (residual oil and on-specification used oil) shall not exceed 7,860,640 gallons during any consecutive 12-months. On-specification used oil shall be blended with residual oil and shall not exceed 10% of the oil consumed. Hours of operation are not restricted (8760 hours/year). *{Permitting Note: The maximum heat input from firing BLS is 1345 MMBtu/hour based on the permitted capacity and an average heating value of 6410 Btu/lb of BLS. The oil firing restriction maintains an annual capacity factor of less than 10% for fossil fuel firing.}* [Application No. 1070005-038-AC; Rules 62-210.200 (PTE) and 62-212.400 (PSD), F.A.C.]

6. Fuel Monitoring: The permittee shall install equipment to continuously monitor the flow rates of all fuels for the No. 4 Recovery Boiler. This may consist of fuel flow meters with integrators to monitor each flow rate. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

7. CEMS: To demonstrate compliance with the emissions standards for the No. 4 Recovery Boiler, the permittee shall properly install, calibrate, operate and maintain continuous emissions monitoring systems (CEMS) to measure and record CO and NO_X emissions in the terms of the applicable standard. The systems shall include continuous monitors to determine the flue gas oxygen content and exhaust flow rate. Each CEMS shall be installed such that representative measurements of emissions or process parameters from the facility are obtained. The permittee shall locate the CEMS by following the procedures contained in the applicable performance specification of 40 CFR Part 60, Appendix B. Within 240 calendar days of completing construction of the fourth level of overfire air, the permittee shall install and certify the required CEMS in accordance with the applicable performance specifications identified in Appendix F (Standard Continuous Monitoring Requirements) of this permit. *{Permitting Note: This unit has existing continuous monitors for determining opacity, SO_2 and TRS emissions.}*

   As an alternative to a continuous flow monitor, the permittee may develop a site specific F-factor for BLS in accordance with the following procedure:

   a. Submit a test protocol for approval to the Bureau of Air Regulation for developing a site specific F-factor for BLS.

   b. Upon written approval from the Bureau of Air Regulation, conduct the testing program in accordance with the protocol.

   c. Develop a site-specific F-factor for BLS based on the testing program and operational data.

   d. Submit a report on the testing program to the Bureau of Air Regulation summarizing: the tests conducted, explanations of any deviations from the test protocol, the data collected, the proposed site-specific F-factor for BLS, and an evaluation of the estimated flow rates compared to the actual measured flow rates.

   e. Submit a request for approval to the Bureau of Air Regulation to use the proposed site-specific F-factor for BLS.

   f. Upon written approval by the Bureau of Air Regulation, the permittee may begin using the site-specific F-factor for BLS to determine the exhaust flow rate. If the Bureau of Air Regulation does not approve the site-specific F-factor for BLS, the permittee shall install a continuous flow monitor.

   [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

EMISSIONS AND PERFORMANCE STANDARDS

8. CO Standards:

   a. After completing installation of the four-level overfire air system, CO emissions shall not exceed 800.0 ppmvd @ 8% O_2 and 1025.4 lb/hour as determined by EPA Method 10 stack testing. *{Permitting Note: Once compliance with this standard is demonstrated and the CO CEMS is certified, this standard becomes obsolete.}*

   b. Once the CO CEMS is certified, compliance shall be determined by data collected from the required CEMS. For the initial 180 calendar days after certifying the CEMS, CO emissions shall not exceed 800.0 ppmvd @ 8% O_2 and 1025.4 lb/hour based on a 30-day rolling CEMS average, excluding periods of startup and shutdown. Thereafter, CO emissions shall not exceed 400.0 ppmvd @ 8% O_2 and 512.7 lb/hour based on a 30-day rolling CEMS average, excluding periods of startup and shutdown. [Rule 62-

212.400 (BACT), F.A.C.]

9. NOx Standards:

   a. After completing installation of the four-level overfire air system, NO_X emissions shall not exceed 80.0 ppmvd @ 8% O_2 and 168.5 lb/hour as determined by EPA Method 10 stack testing. *{Permitting Note: Once compliance with this standard is demonstrated and the NO_X CEMS is certified, this standard becomes obsolete.}*

   b. As determined by data collected from the required CEMS, NO_X emissions shall not exceed 80.0 ppmvd @ 8% O_2 and 168.5 lb/hour based on a 30-day rolling CEMS average, excluding periods of startup and shutdown. [Rule 62-212.400 (BACT), F.A.C.]

10. Opacity Standard: Once the ESP in placed in service during startup of the recovery boiler, visible emissions shall not exceed 20% opacity based on a 6-minute average as determined by the existing COMS and EPA Method 9. [Rule 62-212.400 (BACT), F.A.C.]

11. PM Standard: As determined by EPA Method 5 or 29, PM emissions shall not exceed 0.030 grains per dscf @ 8% O_2 and 75.6 lb/hour based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

12. SO_2 Standard: As determined by data collected from the existing CEMS, SO_2 emissions shall not exceed 153.9 tons per year based on a 12-month rolling CEMS total. [Rule 62-212.400(12), F.A.C.]

13. TRS Standard: As determined by data collected from the existing CEMS, TRS emissions shall not exceed 34.2 tons per year based on a 12-month rolling CEMS total. [Rule 62-212.400(12), F.A.C.]

14. VOC Standard: As determined by EPA Method 25A, VOC emissions shall not exceed 0.20 lb/ton of BLS and 21.0 lb/hour (THC determined as methane) based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

15. ESP Operation: The permittee shall operate and maintain the ESP to minimize PM emissions. The permittee may conduct additional stack tests with fields removed from service to determine compliance with the PM and opacity standards for these periods. During such tests, the permittee shall continuously monitor and record the parameters necessary to determine the secondary power input to the ESP. If these tests demonstrate compliance, the permittee is authorized to operate the ESP under the operating conditions of the tests when conducting repairs or maintenance on the ESP. [Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

COMPLIANCE MONITORING AND TESTING

16. Compliance by CEMS: Compliance with the opacity, SO_2, and TRS standards shall be demonstrated with data collected from the existing COMS and CEMS. Compliance with the CO and NO_X standards shall be demonstrated with data collected from the CEMS required by this permit. The permittee shall comply with the conditions of Appendix F (Standard Continuous Monitoring Requirements) of this permit as the compliance method for the corresponding emissions standards. [Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

17. Standard Testing Requirements: All required emissions tests shall be conducted in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

18. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. [Rule 62-297.310(7)(a)9, F.A.C.]

19. Test Methods: When required, tests shall be performed in accordance with the following methods.

EPA Method	Description of Method and Comments
1 - 4	Methods for Determining Traverse Points, Velocity, Flow Rate, Gas Analysis, and Moisture Content These methods shall be performed as necessary to support other methods.
5	Method for Determining Particulate Matter Emissions
7E	Method for Determining NOx Emissions (Instrumental)
9	Method for Determining Opacity Observations
10	Method for Determining Carbon Monoxide Emissions (Instrumental) The method shall be based on a continuous sampling train.
19	Methods for Determining NO_X, PM, and SO_2 Mass Emission Rates
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)
29	Method for Determining Metals Emissions from Stationary Sources

The above methods are specified in Appendix A of 40 CFR 60 and are adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-4.070(3), 62-204.800(8) and 62-212.400 (BACT), F.A.C.; 40 CFR 60, Appendix A]

20. Compliance Tests: In accordance with the following requirements, the permittee shall have stack tests conducted to demonstrate compliance with the emissions standards specified in this permit for CO, NO_X, PM and VOC.

    a. *Initial Tests*: Initial compliance tests shall be conducted within 60 calendar days of installing the fourth level of overfire air and achieving permitted capacity, but no later than 180 calendar days after initial startup. For the initial CO and NO_X tests prior to certification of the CEMS, the permittee shall demonstrate compliance with at least three hours of data, but no more than nine hours of data. [Rules 62-212.400 (BACT) and 62-297.310(7), F.A.C.]

    b. *Subsequent Tests*: During each federal fiscal year (October 1st to September 30th), compliance tests shall be conducted to determine PM emissions. Because VOC emissions are expected to be low and the CO CEMS will ensure efficient combustion, subsequent tests shall be conducted prior to renewal of the operation permit or when the Department requests a special test pursuant to Rule 62-297.310(7)(b), F.A.C.

    c. *Test Fuel*: Compliance tests shall be conducted when firing BLS at permitted capacity. [Rules 62-4.070(3), 62-212.400 (BACT) and 62-297.310, F.A.C.]

    d. *Operational Data for Tests*: For each test run, the permittee shall monitor and record the following information: fuel feed rate; the secondary power input to the ESP; the flue gas oxygen content (%); CO, NO_X, SO_2 and TRS CEMS data; and opacity COMS data. [Rules 62-297.310 and 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

21. Stack Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Compliance Authority on the results of each such test. The required test report shall be filed with the Compliance Authority as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Compliance Authority 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 information specified in Rule 62-297.310(8), F.A.C. The stack test

shall also report all operational data collected during each test run. [Rule 62-297.310(8), F.A.C.]

22. Semiannual Monitoring Reports: The permittee shall submit a written report to the Compliance Authority summarizing the following for each calendar quarter: CO, NO_X, SO_2, and TRS emissions; opacity; CEMS monitor availability; gallons of oil fired; and total hours of operation. The reports shall identify any exceedance of an emissions or performance limitation. The reports are due within 30 days following the second and fourth calendar quarters. [Rule 62-4.070(3), F.A.C.]

E. No. 4 Multiple Effect Evaporator Set

This subsection of the permit addresses the following emissions unit.

ID	Emission Unit Description
037	Thermal Oxidizer handling the Noncondensable Gas System from the No. 4 Multiple Effect Evaporator (MEE) Set

EXISTING APPLICABLE REGULATIONS

1. State Rule for Kraft Pulp Mills: This emissions unit is subject to the applicable requirements for existing units in Rule 62-296.404, F.A.C. These standards are specified in the Title V air operation permit.
2. NSPS Subpart BB: This emissions unit is subject to the applicable requirements specified in NESHAP Subpart BB of 40 CFR 63 for recovery combustion sources at Kraft pulp mills. These standards are specified in the Title V air operation permit.

MODIFICATIONS AND CAPACITIES

3. No. 4 MEE Set: The permittee is authorized to install a new crystallizer and associated storage/flash tank as a modification to the existing multiple effect evaporator (MEE) set with two associated concentrators (EU-032). The purpose is to increase the temperature and flash-off moisture from the black liquor, which will increase the solids content of the BLS from 65% to approximately 75%. The BLS fired in the existing No. 4 Recovery Boiler will contain less moisture. Emissions from the crystallizer and associated storage/flash tank shall be directed back to the MEE set and collected as part of the existing noncondensable gas (NCG) collection system. The preliminary schedule is to begin construction in May of 2007 and startup the new equipment by May of 2008. [Application No. 1010005-038-AC; Rules 62-212.300 and 62-212.400 (PSD), 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

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

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 these 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 and 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 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 not 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 permittee to cause pollution in contravention of F.S. 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 or 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 and records 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 noncompliance, 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 F.S. 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 F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. 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:
    a. Determination of Best Available Control Technology;
    b. Determination of Prevention of Significant Deterioration; and
    c. Compliance with New Source Performance Standards.
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 or 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:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) 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.

COMMON CONDITIONS

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 (VOC) or organic solvents (OS) 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(Definitions), 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% 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.]

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

RECORDS AND REPORTS

10. 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 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]
11. 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(3), F.A.C.]

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

COMPLIANCE TESTING REQUIREMENTS

1. 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.]
2. 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.]
3. Calculation of Emission Rate: 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.]
4. Applicable Test Procedures [Rule 62-297.310(4), F.A.C.]
   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.

5. Determination of Process Variables [Rule 62-297.310(5), F.A.C.]

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.

6. Sampling Facilities: 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.

7. 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

8. 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 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.

[Rule 62-297.310(8), F.A.C.]

FINAL BACT DETERMINATIONS AND EMISSIONS SUMMARY

PROJECT DESCRIPTION

Georgia-Pacific Consumer Operations LLC operates an existing paper and pulp mill in Palatka using the Kraft sulfate process. In the Kraft process, the digesting liquor (white liquor) is a solution of sodium hydroxide and sodium sulfide that is mixed with wood chips and cooked under pressure. The spent liquor, known as weak black liquor, is concentrated and sodium sulfate is added to make up for chemical losses. The black liquor solids (BLS) are burned in the recovery furnace to produce a smelt of sodium carbonate and sodium sulfide. The smelt is dissolved in water to form green liquor to which quicklime (calcium oxide) is added to convert the sodium carbonate back to sodium hydroxide, which reconstitutes the cooking liquor. The spent lime cake (calcium carbonate) is recalcined in a rotary lime kiln to produce quicklime, which is used to convert the green liquor to cooking liquor. Other steam and energy needs are met by the power boilers, which burn a variety of fuels including oil and natural gas.

This permit authorizes the following major modifications: permanent shutdown of the No. 4 Power Boiler (EU-014); conversion of the No. 5 Power Boiler (EU-015) to natural gas; replacement of the hot-end shell and coolers for the No. 4 Lime Kiln (EU-017); extensive tube replacement and the addition of a fourth level of over-fire air for the No. 4 Recovery Boiler (EU-018); and, the addition of a crystallizer with associated storage/flash tank and modifications to the two existing concentrators associated with the No. 4 multiple effect evaporator set (EU-032).

The permittee conducted a PSD netting analysis based on contemporaneous emissions increases and decreases to avoid PSD preconstruction review for sulfur dioxide (SO_2), sulfuric acid mist (SAM), and total reduced sulfur (TRS). The project is subject to PSD preconstruction review for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM), and volatile organic compounds (VOC). For this permit, the Department determined the Best Available Control Technology (BACT) for the following units: the No. 5 Power Boiler (CO and VOC); the No. 4 Lime Kiln (CO, NO_X, PM, and VOC); and the No. 4 Recovery Boiler (CO, NO_X, PM, and VOC). The No. 4 Combination Boiler is currently under PSD preconstruction review in Project No. 1070005-045-AC for CO, NO_X, PM, and VOC. Throughout this appendix particulate matter emissions are referred to as PM emissions, which serve as a surrogate for regulating $PM_{2.5}$ and PM_{10} emissions.

FINAL BACT DETERMINATIONS

For this project, the applicant conducted a PSD netting analysis that included all contemporaneous emissions increases and decreases. In accordance with Rule 62-212.400 (PSD), F.A.C., the Department establishes the following standards as BACT for CO, NO_X, PM, and VOC emissions.

Pollutant	BACT Standards	Control Technology	Monitoring
No. 5 Power Boiler			
CO [a]	0.185 lb/MMBtu and 105.2 lb/hour	good combustion design and practices for firing natural gas	annual tests
VOC [a]	CO is surrogate standard		no tests required
No. 4 Lime Kiln			
CO [b]	69.0 ppmvd at 10% O_2 and 16.3 lb/hour	good combustion design and practices	annual tests
NO_X	140.0 ppmvd at 10% O_2 and 54.2 lb/hour	good combustion design and practices	annual tests
Opacity	Due to wet plume, scrubber pressure differential and flow rate are continuously monitored.		
PM	0.55 lb/ton processed and 22.9 lb/hour	cyclones and wet venturi scrubber	annual tests
VOC [b]	70.0 ppmvd at 10% O_2 and 9.4 lb/hour	good combustion design and practices	annual tests
No. 4 Recovery Boiler			
CO [c]	400.0 ppmvd @ 8% O_2 and 512.7 lb/hour	good combustion design and practices	CEMS
NO_X [c]	80.0 ppmvd @ 8% O_2 and 168.5 lb/hour	four-level over-fire air system	CEMS
Opacity [d]	20%, 6-minute averages	electrostatic precipitator	COMS
PM	0.030 grains/dscf @ 8% O_2 and 75.6 lb/hour	electrostatic precipitator	annual tests
VOC [e]	0.20 lb/ton of BLS and 21.0 lb/hour	good combustion design and practices	initial/renewal tests

a. For the No. 5 Power Boiler, only CO and VOC emissions will increase after converting to natural gas. All other pollutants will decrease.

b. For the No. 4 Lime Kiln, the testing frequency may be reduced to testing prior to renewal of the operating permit if consecutive tests show emissions below 50% of the emissions standard. CO and VOC emissions are expected to be low due to relatively high kiln temperature and a long residence time. EPA Method 25A used to determine total hydrocarbons measured as methane.

c. For the No. 4 Recovery Boiler, the CO and NO_X standards are based on a 30-day rolling CEMS average excluding emissions data collected during startup and shutdown. For the first 180 days after certifying the CEMS, CO emissions shall not exceed 800.0 ppmvd @ 8% O_2 and 1025.4 lb/hour based on a 30-day rolling CEMS average, excluding data collected during startup and shutdown. The purpose of this interim standard is to provide sufficient time to develop good combustion practices for the four-level overfire air system.

d. For the No. 4 Recovery Boiler, the opacity standard applies once the electrostatic precipitator is placed in service during startup.

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 and the Final Determination issued concurrently with this final PSD air construction permit.

OTHER EMISSIONS STANDARDS

This permit establishes the following additional standards that allow the project to avoid PSD preconstruction review for NO_X, SAM, SO_2, and TRS.

Pollutant	Standards	Monitoring
No. 5 Power Boiler		
NO_X	0.125 lb/MMBtu and 71.1 lb/hour	annual tests
No. 4 Lime Kiln		
SO_2	16.9 ppmvd @ 10% O_2 and 9.1 lb/hour	annual tests
TRS	25.1 tons per year, 12-month rolling CEMS total	CEMS
No. 4 Recovery Boiler		
SO_2	153.9 tons per year, 12-month rolling CEMS total	CEMS
TRS	34.2 tons per year, 12-month rolling CEMS total	CEMS

EMISSIONS SUMMARY

Pollutant	Annual Potential Emissions, tons/year		
	No. 5 Power Boiler [a]	No. 4 Lime Kiln	No. 4 Recovery Boiler
CO	460.8	71.4	2245.6
NO_X	311.4	237.4	738.0
PM	18.9	100.3	331.1
SO_2	1.5	39.9	153.9
TRS	Negligible	25.1 [b]	34.2
VOC	13.7	41.2	92.0

a. Emissions from the No. 5 Power Boiler are based on firing 100% natural gas.

b. Based on current TRS standard in Title V permit.

STANDARD CONTINUOUS MONITORING REQUIREMENTS

The No. 4 Recovery Boiler (EU-018) is subject to the following requirements for the new continuous emissions monitoring systems (CEMS) required for CO and NO_X emissions. The unit also has existing CEMS for SO_2 and TRS emissions and a continuous opacity monitoring systems (COMS).

CEMS OPERATION PLAN

1. CEMS Operation Plan: The permittee shall create and implement a plan for the proper installation, calibration, maintenance, and operation of each CEMS required by this permit. The permittee shall submit the CEMS Operation Plan to the Bureau of Air Monitoring and Mobile Sources for approval prior to CEMS installation. The CEMS Operation Plan shall become effective 60 days after submittal or upon its approval. If the CEMS Operation Plan is not approved, the permittee shall submit a new or revised plan for approval. *{Permitting Note: The Department maintains both guidelines for developing a CEMS Operation Plan and example language that can be used as the basis for the facility-wide plan required by this permit. Contact the Emissions Monitoring Section of the Bureau of Air Monitoring and Mobile Sources at 850/488-0114.}* [Rule 62-4.070(3), F.A.C.]

MONITORS, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

2. Span Values and Dual Range Monitors: The permittee shall set appropriate span values for the CEMS based on the emissions standards and range of operation. If necessary, the permittee shall install dual range monitors in accordance with the CEMS Operation Plan. [Rule 62-4.070(3), F.A.C.]

3. Diluent Monitor: If required by permit to correct the CEMS output to the oxygen concentrations specified in the applicable emissions standard, the permittee shall either install an oxygen monitor or install a CO_2 monitor and use an appropriate F-Factor computational approach. [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

4. Moisture Correction: If necessary, the permittee shall install a system to determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

5. Continuous Flow Monitor: For compliance with mass emission flow rate standards, the permittee shall install a continuous flow monitor to determine the stack exhaust flow rate. The flow monitor shall be certified pursuant to 40 CFR Part 60, Appendix B, Performance Specification 6. Alternatively, the permittee may install a fuel flow monitor and use an appropriate F-Factor computational approach to calculate stack exhaust flow rate. *{Permitting Note: The CEMS Operation Plan will contain additional details and procedures for CEMS installation.}* [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

6. Performance Specifications: The permittee shall evaluate the "acceptability" of each CEMS by conducting the appropriate performance specification. CEMS determined to be "unacceptable" shall not be considered "installed" for purposes of meeting the timelines of this permit. For CO monitors, the permittee shall conduct Performance Specification 4 of 40 CFR Part 60, Appendix B. For NO_X monitors, the permittee shall conduct Performance Specification 2 of 40 CFR Part 60, Appendix B. [Rule 62-4.070(3), F.A.C.]

7. Quality Assurance: The permittee shall follow the quality assurance procedures of 40 CFR Part 60, Appendix F. For CO, the required relative accuracy test audit (RATA) tests shall be performed using EPA Method 10 in Appendix A of 40 CFR Part 60. For NO_X, the RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR Part 60. [Rule 62-4.070(3), F.A.C.]

CALCULATION APPROACH FOR SIP COMPLIANCE

8. CEMS for Compliance: Once adherence to the applicable performance specification for each CEMS is demonstrated, the permittee shall use the CEMS to demonstrate compliance with the applicable emission standards as specified by this permit. [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

9. CEMS Data: Each CEMS shall monitor and record emissions during all operations and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments, and span adjustments. [Rule 62-4.070(3), F.A.C.]

10. Operating Hours and Operating Days: For purposes of this Appendix, the following definitions shall apply. An hour is

the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit. [Rule 62-4.070(3), F.A.C.]

11. 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.

    a. Hours that are not operating hours are not valid hours.

    b. For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

    [Rule 62-4.070(3), F.A.C.]

12. Calculation Approaches: The permittee shall implement the calculation approach specified by this permit for each CEMS, as follows:

    a. *Daily Averages*: A daily average shall be calculated and recorded for each operating day as the arithmetic average of all valid hourly averages occurring from midnight to midnight.

    b. *Rolling 30-day Average*. Compliance with the 30-day rolling average shall be determined after each operating day by calculating and recording the arithmetic average of all valid hourly averages for the previous 30 operating days (compliance period).

    c. *Rolling 12*-month Average:

    d. *Rolling 12*-month Totals:

    [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

13. Minimum Valid Hours: At least one valid hourly average shall be used to calculate the emissions over any averaging period specified by this permit. One valid hourly average shall be sufficient to calculate the emissions over any averaging period. [Rule 62-4.070(3), F.A.C.]

MONITOR AVAILABILITY

14. Monitor Availability: Monitor availability shall be calculated on a quarterly basis for each emission unit as the number of valid hourly averages obtained by the CEMS, divided by the number of operating hours, times 100%. The monitor availability calculation shall not include periods of time where the monitor was functioning properly, but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit, or relative accuracy audits (RAA). Monitor availability for each CEMS shall be 95% or greater in any calendar quarter. Monitor availability shall be reported in the quarterly excess emissions report. In the event 95% availability is not achieved, the permittee shall provide the Department 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. [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

15. Definitions:

    a. *Excess Emissions* (under the Florida SIP) are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction.

    b. *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.

c. *Shutdown* means the cessation of the operation of an emissions unit for any purpose.

d. *Malfunction* means 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.

[Rule 62-210 (Definitions), F.A.C.]

16. 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. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rules 62-210.700(4), F.A.C.]

17. Data Exclusion for SIP Compliance: As per the procedures in this condition, limited amounts of CO and NO_X CEMS emissions data may be excluded from the corresponding compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions replace the provisions in Rule 62-210.700(1), F.A.C.

a. *Excess Emissions.* For purposes of SIP-based permit limits, excess emissions data collected during periods of startup and shutdown may be excluded from compliance calculations as allowed by the permit standards.

b. *Limiting Data Exclusion.* If the compliance calculation using all valid CEMS emission data (as defined in this Appendix) indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

c. *Event Driven Exclusion.* The excess emissions must occur due to an underlying event (startup or shutdown). If there is no underlying event, then no data may be excluded.

d. *Continuous Exclusion.* Data shall be excluded on a continuous basis per event. Data from discontinuous periods shall not be excluded for the same underlying event.

e. *Reporting Excluded Data.* These procedures for excluding SIP-based excess emissions from compliance calculations are not necessarily the same procedures used for "excess emissions" as defined by federal rules. Semiannual reports required by this permit shall indicate the duration of data excluded from SIP compliance calculations as well as the number of excess emissions as defined in the applicable federal rules.

{Permitting Note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.} [Rules 62-212.400 (BACT) and 62-210.700(4), F.A.C.]

18. Notification Requirements: The permittee shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate non-compliance for a given averaging period.

CALCULATING AND REPORTING ANNUAL EMISSIONS

19. CEMS for Calculating Annual Emissions: As defined by this Appendix, all valid data shall be used when calculating annual emissions.

a. Annual emissions shall include data collected during startup, shutdown, and malfunction periods.

b. Annual emissions shall include data collected during periods when the emission unit is not operating, but emissions are being generated (for example, firing fuel to warm up a process for some period of time prior to the emission unit's "official" startup).

c. Annual emissions shall not include data from periods of time where the monitor was functioning properly but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit, or RAA. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

d. Annual emissions shall not include data from periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

20. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hour block average that begins at the top of each hour. For each hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the permittee shall account for emissions during that hour using site-specific data to generate a reasonable estimate of the 1-hour block average.

21. Emissions Calculation: Annual emissions shall be calculated as the sum of all valid emissions occurring during the year.

22. Reporting Annual Emissions: The permittee shall use data from each required CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rules 62-210.370(3) and 62-212.300(1)(e), F.A.C. [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

APPENDIX G. ON-SPECIFICATION USED OIL REQUIREMENTS

The permittee shall comply with the following requirements for on-specification used oil.

1. Specifications for Used Oil: Only "on-specification" used oil containing a PCB concentration of less than 50 ppm shall be fired at this facility.

   a. "On-specification" used oil is defined as used oil that meets the specifications of 40 CFR 279 (Standards for the Management of Used Oil) as listed below.

Constituent/Property	Allowable Level
Arsenic	5 ppm, maximum
Cadmium	2 ppm, maximum
Chromium	10 ppm, maximum
Lead	100 ppm, maximum
Total Halogens	1000 ppm, maximum
Flash point	100° F, minimum

   Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil. The firing of off-specification used oil at this facility is prohibited.

   b. Used oil containing a PCB concentration of 50 ppm or more shall not be fired at this facility and shall not be blended to meet this requirement.

   c. On-specification used oil with a PCB concentration of 2 ppm to less than 50 ppm shall be fired only at normal unit operating temperatures and shall not be fired during periods of startup or shutdown.

   d. On-specification used oil with a PCB concentration of 2 ppm or less may be fired at any time.

   e. On-specification used oil shall meet the maximum sulfur content specified in the permit.

   [40 CFR 279.61]

2. Used Oil Certifications: For each delivery of used oil, the owner or operator shall receive from the marketer a certification that the used oil meets the specifications for "on-specification" used oil and that it contains a PCB concentration of less than 50 ppm. This certification shall also describe the basis for the certification, such as analytical results. Used oil to be fired for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs. Note that a claim that used oil does not contain quantifiable levels of PCBs (<2 ppm) must be documented by analysis or other information. The first person making the claim that the used oil does not contain PCBs is responsible for furnishing the documentation. The documentation can be tests, personal or special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the used oil contains no detectable PCBs. [40 CFR 761.20]

3. Notification to Marketers: Before accepting from each marketer the first shipment of on-specification used oil with a PCB concentration of 2 to less than 50 ppm, the owner or operator shall provide each marketer with a one-time written and signed notice certifying that the owner or operator will fire the used oil in a qualified combustion device and must identify the class of combustion device. The notice must state that EPA or a RCRA-delegated state agency has been given a description of the used oil management activities at the facility and that an industrial boiler or furnace will be used to fire the used oil with a PCB concentration of 2 to 49 ppm. The description of the used oil management activities may be submitted to the Administrator, Hazardous Waste Regulation Section, Florida Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, FL 32399-2400. [and 40 CFR 761.20(e)]

4. Sampling and Analysis:

   a. If the owner or operator does not receive certification from the marketer as described above, the owner or operator shall sample and analyze each batch of used oil to be fired for the following parameters: arsenic, cadmium, chromium, lead, total halogens, flash point, PCBs, and percent sulfur content by weight, ash, and BTU value (BTU per gallon).

b. If the owner or operator receives the required certification from the marketer, the owner or operator shall sample at least one delivery of used oil received each calendar quarter and analyze the sample for arsenic, cadmium, chromium, lead, total halogens, flash point, PCBs, and percent sulfur content by weight, ash, and BTU value (BTU per gallon).

c. Sampling and analysis shall be performed using approved methods specified in latest edition of EPA Publication SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods.

d. If the analytical results show that the used oil does not meet the specifications for on-specification used oil, or that it contains a PCB concentration of 50 ppm or greater, the owner or operator shall immediately cease firing the used oil. The owner or operator shall also immediately notify the appropriate Compliance Authority of the analytical results and indicate the proposed means of disposal of the used oil.

[Rule 62-4.070(3), F.A.C.; 40 CFR Parts 279 and 761]

5. Used Oil Recordkeeping Required: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Compliance Authority:

   a. Within 15 days following each calendar month, record the gallons of on-specification used oil received and fired during the previous calendar month and the previous 12 calendar months.

   b. The name and address of all marketers delivering used oil to the facility.

   c. Copies of the marketer certifications and any supporting information.

   d. If claimed, documentation that the used oil contains less than 2 ppm of PCBs, including the name and address of the person making the claim.

   e. Results of any sampling/analyses conducted.

   f. A copy of the notice to EPA and a copy of the one-time written notice provided to each marketer.

   [Rule 62-4.070(3), F.A.C.; 40 CFR 279.61; and, 40 CFR 761.20(e)]

6. Used Oil Reporting Required: Within 30 days following each calendar quarter, the owner or operator shall submit to the appropriate Compliance Authority, the analytical results and the total amount of on-specification used oil received and fired during the quarter. [Rule 62-4.070(3), F.A.C.; 40 CFR Parts 279 and 761]

Georgia-Pacific

Palatka Pulp and Paper Operations
Consumer Products Division

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

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APR 30 2007

BUREAU OF AIR REGULATION

April 25, 2007

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

RE: Georgia-Pacific, Palatka Operations
Title V No. 1070005-038-AC/Draft PSD-FL-380

Dear Mr. Koerner:

Please find enclosed Proof of Publication of Public Notice for Intent to Issue a Title V Air Operation Permit regarding the modification of the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler.

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

Sincerely,

Michael W. Curtis
Environmental Lead

tk

Enclosure

cc: B. T. Champion, GP Atlanta
Scott Matchett, GP Atlanta

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APR 30 2007
BUREAU OF AIR REGULATION

STATE OF FLORIDA

County of Putnam

The undersigned personally appeared before me, a Notary Public for the State of Florida, and deposes that the Palatka Daily News is a daily newspaper of general circulation, printed in the English language and published in the City of Palatka in said County and State; and that the attached order, notice, publication and/or advertisement:

Florida Department of Enviro

Was published in said newspaper 1 time(s) with said publication being made on the following dates:

04/24/2007

The Palatka Daily News has been continuously published as a daily newspaper, and has been entered as second class matter at the post office at the City of Palatka, Putnam County, Florida, each for a period of more than one year next preceding the date of the first publication of the above described order, notice and/or advertisement.

M. McGill

Sworn to and subscribed to before me this 24th day of April, 2007 by Mary McGill, Administrative Assistant, of the Palatka Daily News, a Florida corporation, on behalf of the corporation.

Mary Kaye Wells

Mary Kaye Wells, Notary Public
My commission expires July 22, 2007

Notary Seal
Seal of Office:

MARY KAYE WELLS
MY COMMISSION # DD 196678
EXPIRES: July 22, 2007
Bonded Thru Notary Public Underwriters

____ Personally known to me, or
____ Produced identification:
__✓__ Did take an oath

PUBLIC NOTICE

Florida Department of Environmental Protection
Bureau of Air Regulation

Project No. 1070005-038-AC/Draft Air Permit No. PSD-FL-380

Georgia-Pacific Consumer Operations LLC - Palatka Mill

Putnam County, Florida

Applicant: The applicant for this project is the Georgia-Pacific Consumer Operations LLC. The applicant's authorized representative and mailing address is: Mr. Keith Washoske, Vice President - Palatka Operations, Georgia-Pacific Consumer Operations LLC, P.O. Box 919, Palatka, Florida 32178-0919.

Facility Location: Georgia-Pacific Consumer Operations LLC operates an existing paper and pulp mill in Palatka located North of CR 216 and West of US 17 in Putnam County, Florida.

Project: The applicant proposes to modify the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler. The project will result in the following potential emissions increases: 1473 tons/year of carbon monoxide (CO); 405 tons/year of nitrogen oxides (NOx); 105 tons/year of particulate matter (PM); 64 tons/year of particulate matter with an aerodynamic diameter of 10 microns or less (PM10); 4.2 tons/year of sulfuric acid mist; and 418 tons/year of volatile organic compounds (VOC). The project includes conversion of the No. 5 Power Boiler from a primary fuel of residual oil to natural gas. This will result in a reduction of more than 3400 tons per year of sulfur dioxide. Pursuant to Rule 62-212.400, F.A.C., the project is subject to preconstruction review for the prevention of significant deterioration (PSD) of air quality for emissions of CO, NOx, PM, PM10, and VOC. The draft permit establishes emissions standards for these pollutants based on the Best Available Control Technologies as determined by the Department.

An air quality impact analysis was conducted. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. The maximum predicted PSD Class II increments of NO2, SO2, and PM10 consumed by all sources in the area, including this project, will be as follows:

PSD Class II Increment

PM10

24-hour	
Consumed (ug/m3)	22
Allowable (ug/m3)	30
Percent Consumed	73
Annual	
Consumed (ug/m3)	0
Allowable (ug/m3)	17
Percent Consumed	0

SO2

3-hour	
Consumed (ug/m3)	125
Allowable (ug/m3)	512
Percent Consumed	24
24-hour	
Consumed (ug/m3)	60
Allowable (ug/m3)	91
Percent Consumed	66
Annual	
Consumed (ug/m3)	6
Allowable (ug/m3)	20
Percent Consumed	40

NO2

Annual	
Consumed (ug/m3)	3
Allowable (ug/m3)	25
Percent Consumed	12

NO2 and PM10 emissions from the project have no significant impact on the PSD Class I Okefenokee National Wilderness Area (NWA), the Chassahowitzka NWA and Wolf Island NWA. The maximum predicted PSD Class I increments of SO2 consumed in these Class I areas by all sources, including this project, will be as follows:

PSD Class I Increment

SO2

3-hour

Annual	
Consumed (ug/m3)	0
Allowable (ug/m3)	2
Percent Consumed	0

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.

Notice of Intent to Issue Air 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 the 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 Draft Permit for a period of 30 days from the date of publication of the Public Notice. Written comments must be postmarked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of this Public Notice or receipt of a written notice, 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 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 (in a proceeding initiated by another party) 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 when and how each petitioner received notice of the agency action or decision; (d) A statement of all disputed issues of material fact; (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 including an explanation of how the alleged facts relate to the specific rules or statutes; 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.

Legal No. 04530987
4/24/07

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APR 30 2007

BUREAU OF AIR REGULATION

STATE OF FLORIDA

County of Putnam

The undersigned personally appeared before me, a Notary Public for the State of Florida, and deposes that the Palatka Daily News is a daily newspaper of general circulation, printed in the English language and published in the City of Palatka in said County and State; and that the attached order, notice, publication and/or advertisement:

Florida Department of Enviro

Was published in said newspaper 1 time(s) with said publication being made on the following dates:

04/24/2007

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M. McGill

Sworn to and subscribed to before me this 24th day of April, 2007 by Mary McGill, Administrative Assistant, of the Palatka Daily News, a Florida corporation, on behalf of the corporation.

Mary Kaye Wells

Mary Kaye Wells, Notary Public
My commission expires July 22, 2007

Notary Seal
Seal of Office:

MARY KAYE WELLS
MY COMMISSION # DD 196678
EXPIRES: July 22, 2007
Bonded Thru Notary Public Underwriters

_____ Personally known to me, or
_____ Produced identification:
__✓__ Did take an oath

PUBLIC NOTICE

Florida Department of Environmental Protection
Bureau of Air Regulation

Project No. 1070005-038-AC/Draft Air Permit No. PSD-FL-380

Georgia-Pacific Consumer Operations LLC - Palatka Mill

Putnam County, Florida

Applicant: The applicant for this project is the Georgia-Pacific Consumer Operations LLC. The applicant's authorized representative and mailing address is: Mr. Keith Wahoska, Vice President - Palatka Operations, Georgia-Pacific Consumer Operations LLC, P.O. Box 919, Palatka, Florida 32178-0919.

Facility Location: Georgia-Pacific Consumer Operations LLC operates an existing paper and pulp mill in Palatka located North of CR 216 and West of US 17 in Putnam County, Florida.

Project: The applicant proposes to modify the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler. The project will result in tha following potential emissions increases: 1473 tons/year of carbon monoxide (CO); 405 tons/year of nitrogen oxides (NOx); 105 tons/year of particulate matter (PM); 84 tons/year of particulate matter with an aerodynamic diameter of 10 microns or less (PM10); 4.2 tons/year of sulfuric acid mist; and 418 tons/year of volatile organic compounds (VOC). The project includes conversion of the No. 5 Power Boiler from a primary fuel of residual oil to natural gas. This will result in a reduction of more than 3400 tons per year of sulfur dioxide. Pursuant to Rule 62-212.400, F.A.C., the project is subject to preconstruction review for the prevention of significant deterioration (PSD) of air quality for emissione of CO, NOx, PM, PM10, and VOC. The draft permit establishes emissions standards for these pollutants based on the Best Available Control Technologies as determined by tha Department.

An air quality impact analyats was conducted. Emissions from the facility will not significantly contribute to or cause a violation of any stato or federal ambient air quality standards. The maximum predicted PSD Class II increments of NO2, SO2, and PM10 consumed by all sources in the area, including this project, will be as follows:

PSD Class II Increment

PM10

24-hour	
Consumed (ug/m3)	22
Allowable (ug/m3)	30
Percent Consumed	73

Annual	
Consumed (ug/m3)	0
Allowable (ug/m3)	17
Percent Consumed	0

SO2

3-hour	
Consumed (ug/m3)	125
Allowable (ug/m3)	512
Percent Consumed	24

24-hour	
Consumed (ug/m3)	60
Allowable (ug/m3)	91
Percent Consumed	66

Annual	
Consumed (ug/m3)	8
Allowable (ug/m3)	20
Percent Consumed	40

Annual	
Consumed (ug/m3)	0
Allowable (ug/m3)	2
Percent Consumed	0

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.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. Tha applicant has provided reasonable assurance that operation of the 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 Draft Permit for a period of 30 days from the date of publication of the Public Notice. Written comments must be postmarked by the close of business (5:00 p.m.), on or before tha end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting

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 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of this Public Notice or receipt of a written notice, 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 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 (in a proceeding initiated by another party) 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 when and how each petitioner received notice of the agency action or decision; (d) A statement of all disputed issues of material fact; (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 including an explanation of how the alleged facts relate to the specific rules or statutes; 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 stata 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

Friday, Barbara

From: Harvey, Mary
Sent: Monday, April 16, 2007 1:21 PM
To: Adams, Patty
Subject: FW: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

Intent 4/13/07

-----Original Message-----
From: Dee_Morse@nps.gov [mailto:Dee_Morse@nps.gov]
Sent: Monday, April 16, 2007 11:51 AM
To: Harvey, Mary
Subject: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

Return Receipt

Your document:	Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT
was received by:	Dee Morse/DENVER/NPS
at:	04/16/2007 09:51:22 AM MDT

Friday, Barbara

From: Harvey, Mary
Sent: Monday, April 16, 2007 9:14 AM
To: Adams, Patty
Subject: FW: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

From: Wahoske, Keith [mailto:KEITH.WAHOSKE@GAPAC.com]
Sent: Friday, April 13, 2007 5:40 PM
To: Harvey, Mary
Subject: RE: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

Ms. Harvey:

We are in receipt of your Email dated 4/13/07

Thank you

Keith Wahoske

-----Original Message-----
From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Friday, April 13, 2007 3:48 PM
To: Wahoske, Keith; Curtis, Michael; Aguilar, Mark J.; Mr. David Buff, P.E., Golder Associates, Inc.; Mr. Chris Kirts, Northeast District Office; Mr. Dee Morse, National Park Service
Cc: Mitchell, Bruce; Koerner, Jeff; Adams, Patty; Gibson, Victoria
Subject: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From:	Harvey, Mary
Sent:	Friday, April 13, 2007 3:50 PM
To:	'little.james@epamail.epa.gov'
Cc:	Mitchell, Bruce; Koerner, Jeff; Adams, Patty
Subject:	FW: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT
Attachments:	Appendix - PSD-FL-380 - FACILITY #1070005-038-AC-DRAFT.PDF; Draft Permit - PSD-FL-380 - FACILITY #1070005-038-AC-DRAFT.PDF; PSD-FL-380 - Intent to Issue - FACILITY #1070005-038-AC-DRAFT.PDF; SIGNED DOCUMENTS FOR PERMIT #1070005-038-AC-DRAFT.pdf; TEPD - 1070005-038-AC - FACILITY #1070005-038-AC-DRAFT.PDF

From: Harvey, Mary
Sent: Friday, April 13, 2007 3:48 PM
To: 'Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC'; 'Mr. David Buff, P.E., Golder Associates, Inc.'; 'Mr. Chris Kirts, Northeast District Office'; 'Mr. Dee Morse, National Park Service'
Cc: Mitchell, Bruce; Koerner, Jeff; Adams, Patty; Gibson, Victoria
Subject: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

Dear Sir/Madam:

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The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

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Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From: Harvey, Mary
Sent: Friday, April 13, 2007 4:24 PM
To: Adams, Patty
Subject: FW: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

From: Curtis, Michael [mailto:MICHAEL.CURTIS@GAPAC.com]
Sent: Friday, April 13, 2007 4:17 PM
To: Harvey, Mary
Subject: Read: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

Your message

To: MICHAEL.CURTIS@GAPAC.com
Subject:

was read on 4/13/2007 4:17 PM.

Friday, Barbara

From: Harvey, Mary

Sent: Friday, April 13, 2007 3:48 PM

To: 'Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC'; 'Mr. David Buff, P.E., Golder Associates, Inc.'; 'Mr. Chris Kirts, Northeast District Office'; 'Mr. Dee Morse, National Park Service'

Cc: Mitchell, Bruce; Koerner, Jeff; Adams, Patty; Gibson, Victoria

Subject: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

Attachments: 1070005.038.AC.D_pdf.zip

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

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The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Florida Department of

Memorandum　Environmental Protection

TO: Trina Vielhauer, Chief - Bureau of Air Regulation

THROUGH: Jeff Koerner, Air Permitting North JK

FROM: Bruce Mitchell

DATE: April 13, 2007

SUBJECT: Draft Air Permit No. PSD-FL-380
Project No. 1070005-038-AC
Georgia-Pacific Consumer Operations LLC
Modifications to the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination (with BACT Determination);
- Draft PSD Permit; and
- P.E. Certification

The P.E. certification briefly summarizes the proposed permit project. The Technical Evaluation and Preliminary Determination provide a detailed description of the project, rationale, and conclusion. I recommend your approval of the attached Draft Permit for this project.

Attachments

P.E. CERTIFICATION STATEMENT

APPLICANT

Georgia-Pacific Consumer Operations LLC
P.O. Box 919
Palatka, Florida 32178-0919

Project No. 1070005-038-AC
Permit No. PSD-FL-380
PSD Modification
Palatka Mill
Putnam County, Florida

PROJECT DESCRIPTION

Georgia-Pacific operates an existing Kraft sulfate process pulp and paper mill located North of County Road 216 and West of U.S. Highway 17 in Palatka, Putnam County, Florida. This permit authorizes the following major modifications: permanent shutdown of the No. 4 Power Boiler; conversion of the No. 5 Power Boiler to natural gas; replacement of the hot-end section and cooler tubes for the No. 4 Lime Kiln; extensive tube replacement and modification of the combustion air system (including the addition of a fourth level of overfire air) for the No. 4 Recovery Boiler; and the addition of a crystallizer with associated storage/flash tank and modifications to the two concentrators associated with the No. 4 multiple effect evaporator set.

The permittee conducted a PSD netting analysis based on contemporaneous emissions increases and decreases to avoid PSD preconstruction review for SO_2, SAM, and TRS. The project is subject to PSD preconstruction review for CO, NO_X, PM, and VOC. For this permit, the Department determined the Best Available Control Technology (BACT) for the following units: the No. 5 Power Boiler (CO and VOC); the No. 4 Lime Kiln (CO, NO_X, PM, and VOC); and the No. 4 Recovery Boiler (CO, NO_X, PM, and VOC). The No. 4 Combination Boiler is currently under PSD preconstruction review in Project No. 1070005-045-AC for CO, NO_X, PM, and VOC.

I HEREBY CERTIFY *that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including, but not limited to, the electrical, mechanical, structural, hydrological, geological, and meteorological features).*

Jeffery F. Koerner 4-13-07

Jeffery F. Koerner, P.E.
Registration No. 49441

(Date)

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

April 13, 2007

Mr. Keith Wahoske
Georgia-Pacific Consumer Operations LLC
Palatka Mill
P.O. Box 919
Palatka, Florida 32178-0919

Re: Draft Air Permit No. PSD-FL-380
Project No. 1070005-038-AC
Georgia-Pacific Consumer Operations LLC – Palatka Mill
Request to Modify the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler

Dear Mr. Wahoske:

On July 18, 2006, Georgia-Pacific Consumer Operations LLC submitted an application to modify the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler at the Palatka Mill, which is located North of CR 216 and West of US 17, Palatka, Putnam County, Florida. Enclosed are the following documents: Technical Evaluation and Preliminary Determination, Draft Permit, Written Notice of Intent to Issue Air Permit, and Public Notice of Intent to Issue Air Permit.

The Technical Evaluation and Preliminary Determination summarizes the Bureau of Air Regulation's technical review of the application and provides the rationale for making the preliminary determination to issue a draft permit. The proposed Draft Permit includes the specific conditions that regulate the emissions units covered by the proposed project. The Written Notice of Intent to Issue Air Permit provides important information regarding: the Permitting Authority's intent to issue an air permit for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue an air permit; the procedures for submitting comments on the Draft Permit; the process for filing a petition for an administrative hearing; and the availability of mediation. The Public Notice of Intent to Issue Air Permit is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project.

If you have any questions, please contact the Project Engineer, Bruce Mitchell, at 850/413-9198.

Sincerely,

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Georgia-Pacific Consumer Operations LLC
P.O. Box 919
Palatka, Florida 32178-0919

Authorized Representative:
Mr. Keith Wahoske, Vice President – Palatka Operations

Draft Air Permit No. PSD-FL-380
Project No. 1070005-038-AC
Palatka Mill
Modifications of the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler
Putnam County, Florida

Facility Location: Georgia-Pacific Consumer Operations LLC operates an existing paper and pulp mill in Palatka located North of CR 216 and West of US 17 in Putnam County, Florida.

Project: The applicant proposes to modify the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler. Details of the project are provided in the application and the enclosed "Technical Evaluation and Preliminary Determination".

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.

Notice of Intent to Issue Air 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 the 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.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Permit (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at the address or phone number listed above. Pursuant to Rule 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 7 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of 30 days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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 (Telephone: 850/245-2241; Fax: 850/245-2303). 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 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 (in a proceeding initiated by another party) 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 when and how each petitioner received notice of the agency action or decision; (d) A statement of all disputed issues of material fact; (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 including an explanation of how the alleged facts relate to the specific rules or statutes; 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.

Trina 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 electronically (received receipt requested) before the close of business on 4/13/07 to the persons listed below.

Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC (keith.wahoske@gapac.com)
Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC (michael.curtis@gapac.com)
Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC (MJAGUILA@GAPAC.com)
Mr. David Buff, P.E., Golder Associates, Inc. (dbuff@golder.com)
Mr. Chris Kirts, Northeast District Office (chris.kirts@dep.state.fl.us)
Mr. Jim Little, U.S. EPA, Region 4 (little.james@epamail.epa.gov)
Mr. Dee Morse, National Park Service (dee_morse@nps.gov)

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 (Clerk) 4/13/07 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Bureau of Air Regulation
Project No. 1070005-038-AC/Draft Air Permit No. PSD-FL-380
Georgia-Pacific Consumer Operations LLC – Palatka Mill
Putnam County, Florida

Applicant: The applicant for this project is the Georgia-Pacific Consumer Operations LLC. The applicant's authorized representative and mailing address is: Mr. Keith Wahoske, Vice President – Palatka Operations, Georgia-Pacific Consumer Operations LLC, P.O. Box 919, Palatka, Florida 32178-0919.

Facility Location: Georgia-Pacific Consumer Operations LLC operates an existing paper and pulp mill in Palatka located North of CR 216 and West of US 17 in Putnam County, Florida.

Project: The applicant proposes to modify the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler. The project will result in the following potential emissions increases: 1473 tons/year of carbon monoxide (CO); 405 tons/year of nitrogen oxides (NO_X); 105 tons/year of particulate matter (PM); 84 tons/year of particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}); 4.2 tons/year of sulfuric acid mist; and 418 tons/year of volatile organic compounds (VOC). The project includes conversion of the No. 5 Power Boiler from a primary fuel of residual oil to natural gas. This will result in a reduction of more than 3400 tons per year of sulfur dioxide. Pursuant to Rule 62-212.400, F.A.C., the project is subject to preconstruction review for the prevention of significant deterioration (PSD) of air quality for emissions of CO, NO_X, PM, PM_{10}, and VOC. The draft permit establishes emissions standards for these pollutants based on the Best Available Control Technologies as determined by the Department.

An air quality impact analysis was conducted. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. The maximum predicted PSD Class II increments of NO_2, SO_2, and PM_{10} consumed by all sources in the area, including this project, will be as follows:

PSD Class II Increment

	Consumed ($\mu g/m^3$)	Allowable ($\mu g/m^3$)	Percent Consumed
PM_{10}			
24-hour	22	30	73
Annual	0	17	0
SO_2			
3-hour	125	512	24
24-hour	60	91	66
Annual	8	20	40
NO_2			
Annual	3	25	12

NO_2 and PM_{10} emissions from the project have no significant impact on the PSD Class I Okefenokee National Wilderness Area (NWA), the Chassahowitzka NWA and Wolf Island NWA The maximum predicted PSD Class I increments of SO_2 consumed in these Class I areas by all sources, including this project, will be as follows:

PSD Class I Increment

	Consumed ($\mu g/m^3$)	Allowable ($\mu g/m^3$)	Percent Consumed
SO_2			
3-hour	24.4	25	98
24-hour	4.14	5	83
Annual	0	2	0

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.

Notice of Intent to Issue Air 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 the 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 Draft Permit for a period of 30 days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of this Public Notice or receipt of a written notice, 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 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 (in a proceeding initiated by another party) 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 when and how each petitioner received notice of the agency action or decision; (d) A statement of all disputed issues of material fact; (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 including an explanation of how the alleged facts relate to the specific rules or statutes; 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.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

PROJECT

Draft Permit No. 1070005-038-AC (PSD-FL-380)
Georgia-Pacific Palatka Mill
Facility ID No. 1070005
Modification of the No. 5 Power Boiler, No. 4 Lime Kiln, and No. 4 Recovery Boiler

COUNTY

Putnam County, Florida

APPLICANT

Georgia-Pacific Consumer Operations LLC
Palatka Mill
P.O. Box 919
Palatka, Florida 32178-0919

PERMITTING AUTHORITY

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

April 13, 2007

1. GENERAL PROJECT INFORMATION

Facility and Location

The Georgia-Pacific Consumer Operations LLC operates an existing pulp and paper mill (SIC Nos. 2611 and 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. This site is in an area that is in attainment (or designated as unclassifiable) for each air pollutant subject to a National Ambient Air Quality Standard (NAAQS).

The existing mill uses the Kraft sulfate process in which the digesting liquor (white liquor) is a solution of sodium hydroxide and sodium sulfide that is mixed with wood chips and cooked under pressure. The spent liquor, known as weak black liquor, is concentrated and sodium sulfate is added to make up for chemical losses. The black liquor solids (BLS) are burned in the recovery furnace to produce a smelt of sodium carbonate and sodium sulfide. The smelt is dissolved in water to form green liquor to which quicklime (calcium oxide) is added to convert the sodium carbonate back to sodium hydroxide, which reconstitutes the cooking liquor. The spent lime cake (calcium carbonate) is recalcined in a rotary lime kiln to produce quicklime, which is used to process the green liquor to cooking liquor.

Steam and energy needs are met by the power boilers, which burn a variety of fuels including fuel oil and natural gas. The recovery boiler, lime kiln, and power boiler all fire fuels and produce products of incomplete combustion, including carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), total reduced sulfur (TRS), and volatile organic compounds (VOC). On the following page, Figure 10.2-1 shows the typical process flow for a Kraft sulfate pulping and recovery process.

Facility Regulatory Categories

- The facility is a major source of hazardous air pollutants (HAP).
- The facility operates no units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution.
- The facility is a major stationary source subject to the Prevention of Significant Deterioration (PSD) of Air Quality.

Project Description

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

No. 5 Power Boiler (EU-015): Currently, the No. 5 Power Boiler fires residual oil with a maximum sulfur content of 2.35% by weight. This boiler is the largest source of SO_2 emissions at the plant and is considered an eligible unit subject to Rule 62-296.340, F.A.C. for the Best Available Retrofit Technology (BART). In conjunction with this PSD project and the BART program, the No. 5 Power Boiler will be completely converted to fire natural gas as the sole fuel. This modification results in large reductions of SAM and SO_2 emissions to avoid PSD preconstruction review for the project and also satisfy the program requirements for BART. Since the unit will be limited only to gaseous fuel, the existing electrostatic precipitator will be removed.

No. 4 Lime Kiln (EU-017). Approximately 62 feet of the hot-end kiln shell and all ten coolers located in this section will be replaced. The new coolers will be mounted with an improved bracket design to prevent stress cracks underneath the coolers. The total cost of the lime kiln project is estimated at $1.8 million.

No. 4 Recovery Boiler (EU-018) and No. 4 Multiple Effect Evaporator Set (EU-032): The applicant proposes numerous physical changes to the recovery boiler, including:

- Extensive replacement of tubes will be made in the superheater, economizer, main generating banks and floor. The tube replacements are not considered routine because the original tubes have been in place since the unit was originally constructed in the 1970s. The estimated cost for re-tubing the boiler is $24 million.
- Physical changes will be made to the combustion air system to lower the peak furnace exhaust gas temperature and velocity into the superheater. This effort is intended to reduce potential corrosion and pluggage of the superheater. The modified air system is also expected to reduce PM/PM_{10} carry over and fouling in the boiler convection tube banks. By staging the combustion air, an increase in boiler efficiency is anticipated, which may reduce some pollutants due to better combustion (i.e., CO, PM/PM_{10}, and TRS), but may result in slight increases in NO_X. 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 of steam for a 24-hour average based on steam conditions of 850° F to 900° F at 1250 psi. The maximum fuel firing rate of 210,000 lbs/hour of BLS will not change. The estimated cost to modify the combustion air system is less than $2 million.

- The black liquor evaporator system, specifically the No. 4 Multiple Effect Evaporator (MEE) set, will be modified to increase the concentration of BLS from 65% to 75%. The purpose of the modification is to improve the combustion efficiency of the No. 4 Recovery Boiler by reducing the amount of water in the 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" the liquid water to a vapor. The vapor 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 by improving the firing of BLS. Increasing the recovery boiler efficiency should reduce the steam demand for other existing boilers that fire fuel oil. However, the increased solids content may result in increased particulate loading to the exhaust flue gas. The estimated cost to modify the black liquor evaporator system is $5 to $6 million.
- In the existing concentrators, some internal baffles will be removed and several downcomer piping resized. This effort will improve liquor circulation and increase velocity through the tubes, which should reduce scaling and fouling as well as the frequency of "boil outs", which reduces component life. 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 will allow the fuel feed system to more closely match the existing capacity of the No. 4 Recovery Boiler. Emissions generated from the external heat exchanger will be controlled by the existing NCG collection system.

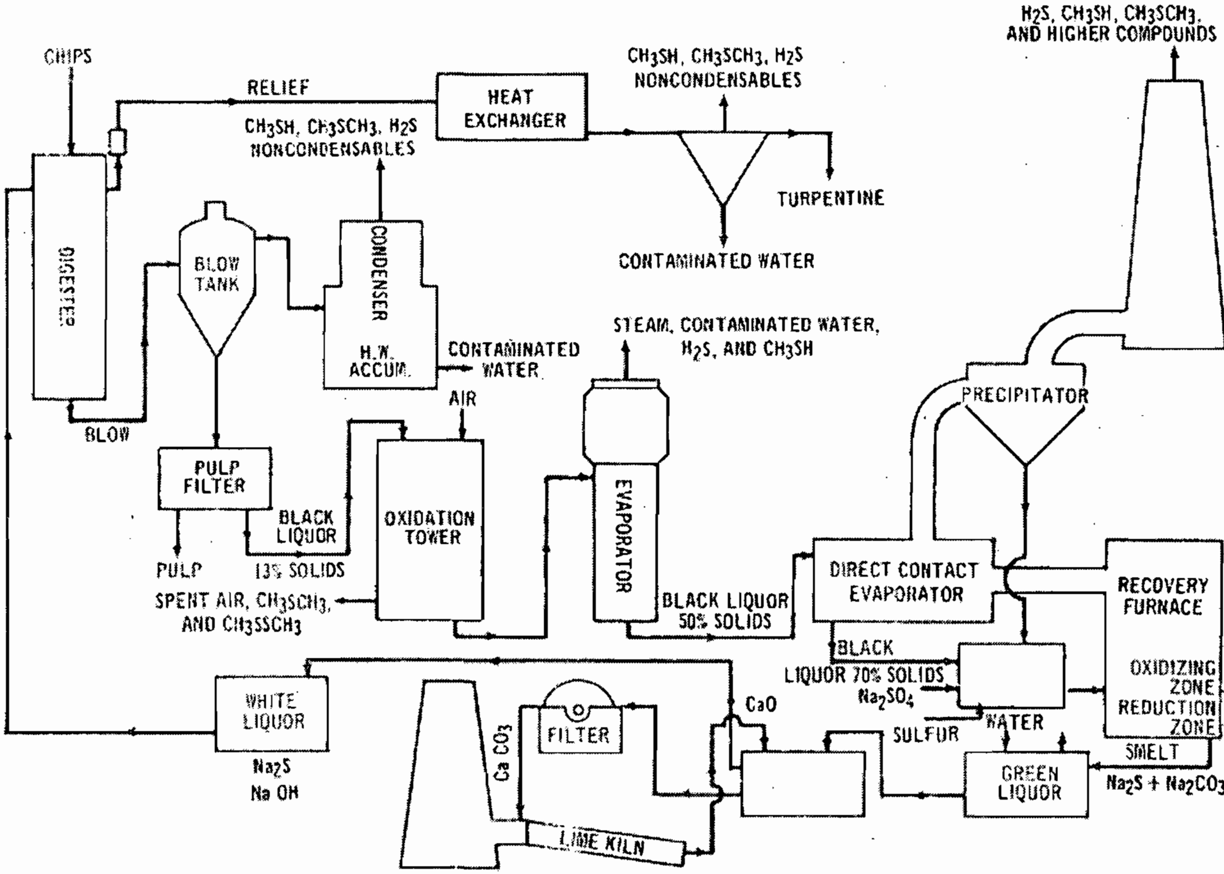

Figure 10.2-1. Typical kraft sulfate pulping and recovery process.

Reference: Section 10.2, Chemical Wood Pulping, AP 42, Fifth Edition, *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources*, September 1990.

Proposed Schedule

Excluding the cost of converting the No. 5 Power Boiler to natural gas, the total cost of the project is estimated to be approximately $32 million. The preliminary schedule is to complete all of the work except for the crystallizer project during the June/July 2007 outage. It is likely that construction on the crystallizer project will not begin until some time in 2008.

Reviewing and Processing Schedule

July 18, 2006: Receipt of application;

August 17, 2006: Request for additional information;

September 29, 2006: Receipt of additional information;

October 27, 2006: Request for additional information;

November 16, 2006: Receipt of additional information;

December 15, 2006: Request for additional information;

February 5, 2007: Receipt of additional information, but still incomplete per response #1;

March 15, 2007: Receipt of additional information;

March 16, 2007: Receipt of additional information; and

April 5, 2007: Receipt of additional information.

2. RULE APPLICABILITY

State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.), which authorize the Department of Environmental Protection (Department) 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 F.A.C.: 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); 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). The affected emissions units are subject to the following industry-specific regulations:

- Rule 62-296.404, F.A.C. for Kraft pulp mills;
- Rule 62-296.405, F.A.C. for fossil fuel steam generators with more than 250 MMBtu per hour of heat input; and
- Rule 62-212.400, F.A.C. for PSD preconstruction review.

The existing permits capture the applicable provisions for Rules 62-296.404 and 62-296.405, F.A.C. These requirements will not be repeated for this project.

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 NESHAPs based on the Maximum Achievable Control Technology (MACT) for given source categories. The Department adopts these federal regulations in Rule 62-204.800, F.A.C. Specifically, emissions units at the mill are subject to the following federal regulations:

- 40 CFR 60, NSPS Subpart A for the general provisions;
- 40 CFR 60, NSPS Subpart Db for industrial boilers;
- 40 CFR 60, NSPS Subpart Kb for petroleum storage tanks;
- 40 CFR 60, NSPS BB for Kraft pulp mills;
- 40 CFR 63, NESHAP Subpart A for the general provisions;

- 40 CFR 63, NESHAP Subpart S for Kraft pulp mills;
- 40 CFR 63, NESHAP Subpart MM for Kraft pulp mills;
- 40 CFR 63, NESHAP Subpart RR for individual drain systems;
- 40 CFR 63, NESHAP Subpart JJJJ for core manufacturing activities at pulp and paper mills; and
- 40 CFR 63, NESHAP Subpart DDDDD for industrial boilers.

The existing No. 5 Power Boiler, No. 4 Recovery Boiler and No. 4 Lime Kiln are not subject to any new NSPS or NESHAP provisions because the reconstruction costs for each emissions unit are less than 50% of the estimated costs to construct a new unit.

General PSD Applicability

The Department regulates major stationary sources in accordance with Florida's PSD program pursuant to Rule 62-212.400, F.A.C. A PSD preconstruction review is required in areas currently in attainment with the state and federal Ambient Air Quality Standards 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; 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 or more of lead.

New projects at existing PSD-major stationary sources are reviewed for PSD applicability based on net emissions increases from the project. Each PSD pollutant is evaluated for applicability based on emissions thresholds known as the Significant Emission Rates as defined in Rule 62-210.200, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant". In addition, applicants may choose to conduct a "PSD netting analysis" that includes all emissions increases as well as all emissions decreases for a 5-year period contemporaneous with the project to determine whether or not a PSD significant emissions increase will occur. Although a facility may be "major" for only one PSD pollutant, the project may be "significant" for several PSD pollutants. For each significant PSD pollutant, the applicant must employ the Best Available Control Technology (BACT) to minimize emissions and conduct an air quality analysis that demonstrates emissions from the project will not cause or contribute to 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 or otherwise designated as unclassifiable. The existing facility belongs to one of the 28 PSD Major Facility Categories (Kraft Pulp Mills) as defined for major stationary sources in Rule 62-210.200, F.A.C. Potential emissions of at least one pollutant from the existing plant are greater than 100 tons per year, which makes the plant a PSD major stationary source of air pollution. Therefore, the project must be reviewed for PSD applicability.

For the project under review, the applicant proposes modifications to the existing No. 4 Recovery Boiler, No. 4 Lime Kiln, and No. 5 Power Boiler. As a separate project, the applicant is also proposing to modify the No. 4 Combination Boiler in addition to a recent PSD permit that modified the existing bark handling system. Due to the nature and close timing of these projects, the Department will review the emissions increases as a single project. The applicant conducted a netting analysis to determine PSD applicability for the affected units considering all emissions increases as well as all emissions decreases for a 5-year period contemporaneous with the project. In this manner, the full emissions increases could be accounted for in the ambient air quality analysis and individual projects will not inadvertently escape BACT determinations. The following table summarizes the applicant's PSD netting analysis for this project.

Pollutant	Emissions in Tons per Year					Subject to PSD?
	Baseline Emissions [1]	Future Potential Emissions [1]	Contemporaneous Emission Changes [4]	Net Emissions Change	PSD Significant Emission Rates	
CO	2094.7	3548.3	19.6	1473.2	100	Yes
NO_X	1504.5	1913.1	- 3.4	405.2	40	Yes
PM	530.0	641.7	- 6.7	105.0	25	Yes
PM_{10}	433.5	521.3	- 4.3	83.5	15	Yes

Pollutant	Emissions in Tons per Year					Subject to PSD?
	Baseline Emissions [1]	Future Potential Emissions [1]	Contemporaneous Emission Changes [4]	Net Emissions Change	PSD Significant Emission Rates	
SAM	183.5	54.5	0.3	- 128.7	7	No
SO_2	4179.2	1064.6	- 362.0	- 3476.6	40	No
TRS	26.0	83.7	- 53.5	4.2	10	No
VOC	329.2	805.2	- 58.1	417.9	40	Yes
Lead	0.260	0.380	- 0.005	0.115	0.6	No
Mercury	0.006	0.008	~ 0	0.002	0.1	No
Fluorides	0.449	0.095	- 0.027	- 0.381	3	No

The PSD netting analysis includes the following emissions units directly affected by this project: No. 4 Power Boiler, No. 5 Power Boiler, No. 4 Lime Kiln, and No. 4 Recovery Boiler. Modification of the No. 4 Combination Boiler was included as a related project, which is under review in Project No. 1070005-045-AC. Subject to the conditions of Permit No. PSD-FL-341, modification of the bark handling system was included as part of this project. The PSD netting analysis also included the previous air construction permit projects from the contemporaneous period: MACT I Compliance, new package boiler, and brown stock washer and delignification system. Emissions from previous pollution control projects which were accounted for in a modeling analysis were not included in the netting analysis. See application for detailed emissions estimates for each unit and project.

Based on the applicant's netting analysis, the projects are subject to PSD preconstruction review for emissions of CO, NO_X, PM/PM_{10}, and VOC. The applicant is required to conduct an air quality analysis to determine ambient impacts and propose BACT controls for the emissions units affected by this project: No. 5 Power Boiler, No. 4 Lime Kiln and No. 4 Recovery Boiler. The No. 4 Power Boiler will be shut down as part of this current project. Previously, Permit No. 1070005-028-AC determined BACT for PM/PM_{10} and VOC emissions from the modified bark handling system. Pending Project No. 1070005-045-AC will determine BACT for CO, NO_X, PM/PM_{10}, and VOC from the No. 4 Combination Boiler.

General Requirements for BACT Reviews

Pursuant to Rule 62-210.200, F.A.C., the "Best Available Control Technology" or "BACT" is defined as:

(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. In general, the Department conducts such reviews consistent with the "top-down methodology" described by EPA. The proposed project requires the Department to make BACT determinations for CO, NO_X, PM/PM_{10}, and VOC emissions from the No. 4 Recovery Boiler and the No. 4 Lime Kiln. Once the No. 5 Power Boiler is converted to natural gas, CO and VOC emissions will potentially increase, but SO_2 and NO_X emissions will decrease. Therefore, the Department will only make BACT determinations for CO and VOC emissions from the No. 5 Power Boiler.

Throughout the BACT analysis, the Department will use PM emissions as a surrogate to also reduce $PM_{2.5}$ and PM_{10} emissions. For this project, conversion of the No. 5 Power Boiler to natural gas will directly reduce all forms of PM emissions as well as SAM and SO_2 emissions, which directly affect visibility.

General Requirements for the PSD Air Quality Analysis

In addition to the required BACT determinations, a PSD preconstruction review also requires an air quality analysis for each significant PSD pollutant. The air quality analysis consists of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of predicted project concentrations with the National Ambient Air Quality Standards and PSD increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility; and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. The proposed project requires the following air quality analyses: a significant impact analysis for CO, NO_2 and PM/PM_{10}; a PSD increment analysis for NO_2; an Ambient Air Quality Standards (AAQS) analysis for NO_2; and, an analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts.

3. BACT REVIEW FOR THE NO. 5 POWER BOILER (EU-015)

Discussion of Emissions Changes

Currently, the No. 5 Power Boiler fires residual oil with a maximum sulfur content of 2.35% by weight. This boiler is the largest source of SO_2 emissions at the plant and is considered an eligible unit subject to Rule 62-296.340 (BART), F.A.C. The Department is reviewing a request for an exemption from the BART program based on a visibility modeling analysis. In conjunction with this PSD project and the BART program, the No. 5 Power Boiler will be completely converted to fire natural gas as the sole fuel. The conversion allows this project to avoid PSD preconstruction review for SO_2 and SAM emissions and also satisfy the program requirements under BART. The project is subject to PSD preconstruction review for CO, NO_X, PM/PM_{10}, and VOC emissions. For these pollutants, the following table shows the applicant's estimate of potential emissions changes for these pollutants due to conversion to natural gas.

Pollutant	Emissions, Tons per Year		
	Baseline	Future Potential	Change
CO	48.9	460.8	+ 411.9
NO_X	459.6	311.5	- 148.1
PM	193.6	18.9	- 174.7
PM_{10}	166.5	18.9	- 147.6
VOC	2.7	13.7	+ 11.0

CO and NO_X emissions are based on the natural gas burner bid specifications. PM, PM_{10}, and VOC emissions are based on the emissions factors in Table 1.4-2 of AP-42 for natural gas combustion. Since only CO and VOC emissions are predicted to increase for the No. 5 Power Boiler as a result of the conversion to natural gas, a BACT review is required only for these pollutants. The applicant notes that actual emissions may decrease for all pollutants as a result of the project.

CO and VOC Emissions – No. 5 Power Boiler

Applicant's Proposal

Thermal and catalytic oxidation systems are technically feasible add-on controls. Both technologies would require the firing of additional natural gas to maintain proper destruction temperatures. The applicant conducted a cost analysis for a catalytic oxidation system that concluded annual costs would be more than $8000 per ton of CO removed. The applicant believes these costs are excessive. The applicant proposes a CO BACT limit of 0.185 lb/MMBtu of heat input based on the burner specifications and the efficient combustion of natural gas. Using the emissions factor in Table 1.4-2 of AP-42 for firing natural gas in an industrial boiler, VOC emissions are expected to be less than 0.005 lb/MMBtu and 14 tons per year. Because of the very low VOC emissions expected, the applicant proposes the CO BACT standard as a surrogate BACT standard for VOC emissions.

Department's Review

The burner specification of 0.185 lb CO per MMBtu of heat input at a flue gas oxygen content of 7% oxygen is equivalent to approximately 200 ppmvd. For comparison, the NESHAP Subpart DDDDD requirements for new industrial boilers establishes a CO standard of 400 ppmvd @ 7% oxygen as a surrogate for ensuring complete combustion resulting in low emissions of organic HAP. Natural gas consists of organic compounds, which the boiler will efficiently combust.

Available options for the control of CO and VOC emissions include thermal and catalytic oxidation equipment. However, at the expected low emissions rates for these pollutants, these add-on controls would be cost prohibitive. The Department accepts the applicant's proposal and makes the following draft BACT determinations based on the efficient combustion of natural gas:

> As determined by EPA Method 10, CO emissions shall not exceed 0.185 lb/MMBtu of heat input and 105.2 lb/hour based on the average of three test runs.

Compliance shall be determined by initial an annual stack tests for CO emissions. The CO standard also serves as a surrogate standard representing low VOC emissions from the efficient combustion of natural gas.

4. BACT ANALYSIS FOR THE NO. 4 LIME KILN (EU-017)

The No. 4 Lime Kiln recalcines the spent lime cake (calcium carbonate) to produce the quicklime (calcium oxide), which is used to convert the green liquor to cooking liquor. The maximum processing rate of the No. 4 Lime Kiln is 41.5 tons per hour of calcium carbonate (including inert materials) based on a 24-hour average. The maximum production rate is 19.4 tons per hour of lime. At permitted capacity, the maximum flow rate is 54,200 dscfm @ 10% oxygen. The lime kiln normally operates with flue gas oxygen contents in the 4 to 6 percent range (by volume). The lime kiln fires residual fuel oil containing 2.35% sulfur by weight as the primary fuel. The maximum heat input rate is 140 MMBtu per hour when firing a maximum of 933 gallons per hour of residual oil with a heating value of 150,000 Btu per gallon. There is no restriction on the hours of operation. Particulate matter emissions are controlled by a cyclonic dust collector followed by a wet venturi scrubber. The following table summarizes the applicant's estimated potential emissions changes for the No. 4 Lime Kiln due to the project.

Pollutant	Emissions, Tons per Year		
	Baseline	Future Potential	Change
CO	6.8	71.5	+ 64.7
NO_X	101.4	297.4	+ 196.0
PM	51.3	130.2	+ 78.9
PM_{10}	50.4	128.0	+ 77.6
VOC	2.5	41.4	+ 38.9

The applicant notes that it is likely that there will be no increase in actual emissions from the project. As shown in the above table, the project will increase emissions of CO, NO_X, PM, and VOC; therefore, BACT determinations are required for these pollutants.

Discussion of Exhaust Flow Rate

The Department's ARMS database identifies the exhaust flow rate through the lime kiln as 44,800 acfm, which is equivalent to 24,299 dscfm @ 4% oxygen and 37,400 dscfm @ 10% oxygen. The PSD application identifies the exhaust flow rate through the lime kiln as 58,900 acfm, which is equivalent to 54,200 dscfm @ 10% oxygen. Subsequent tests in 1993 indicated the maximum flow rate was 44,500 dscfm @ 10% oxygen, which was presented in a 1995 PSD application. More recent tests identify the maximum flow rate as 54,200 dscfm @ 10% oxygen. The applicant requests that the maximum flow rate be updated to 58,900 acfm and 54,200 dscfm @ 10% oxygen. In addition, the applicant requests that the mass emissions rates be based on the updated flow rate.

PM Emissions - No. 4 Lime Kiln

The lime dust is made up of particles of sizes ranging from 1 to 100 microns in diameter, while the soda fume consist of very small particles, most less than 1 micron in diameter. Therefore, the lime dust is easily removed from the exhaust gas, but the soda fume proves more difficult. For the existing lime kiln, lime dust is captured by cyclones and recycled back into the process. Exhaust gas from the cyclone is further controlled by a wet venturi scrubber. The most stringent current PM standard for the lime kiln is the NESHAP Subpart MM standard of 0.064 grains per dscf @ 10% O_2, which is equivalent to 29.7 lb/hour.

Applicant's Proposal

Common control equipment for removing PM includes baghouses, electrostatic precipitators, wet scrubbers, and cyclonic separators. Baghouses typically consist of a series of hanging, fine mesh bags and can be designed for removal efficiencies greater than 99%. Electrostatic precipitators charge particles for collection on large hanging plates with removal efficiencies greater than 99%. High-energy wet scrubbers are effective in removing particulate matter with control efficiencies of 95% to 99%. Cyclonic separators use centrifugal forces and low pressure caused by the spinning motion to remove particles with efficiencies ranging from 25% to 95% depending on material density, size and shape. Based on the RACT/BACT/LAER Clearinghouse (RBLC) entries from 1990 to present, all of these control technologies have been applied to lime kilns.

The lime kiln exhaust has a moisture content of approximately 35% and an exit temperature of approximately 600° F (range of 550 to 700° F). Condensation of moisture in a baghouse controlling lime dust would cause blinding, plugging, high pressures, and premature bag failures. For this reason, the applicant believes that a baghouse is better suited for "dry" gas streams and rejects a baghouse for application on the lime kiln.

The existing No. 4 Lime Kiln is currently equipped with a cyclonic dust collector followed by a wet venturi scrubber using fresh water as the scrubbing media. Potentially, an electrostatic precipitator or baghouse could be added to further reduce PM emissions. The applicant identified the following mills that employ the combination of electrostatic precipitator/venturi scrubber on a lime kiln: Koch Cellulose Mill in Leaf River, Mississippi; Koch Cellulose Mill in Brunswick, Georgia; Georgia-Pacific Mill in Port Hudson, Louisiana; and Georgia-Pacific Mill in Naheola, Alabama. Due to the applicant's concerns regarding feasibility of a baghouse, the applicant provided only a cost analysis for adding an electrostatic precipitator to the existing system.

The applicant estimates the annualized cost to operate and maintain an electrostatic precipitator (including capital recovery) at $1,403,393. After control by the existing combination of cyclones/venturi scrubber, baseline PM emissions were estimated as 58 tons per year. Assuming 99% control efficiency for the electrostatic precipitator, the additional PM emissions removed would be 57 tons per year. Based on these estimates, the cost effectiveness to add an electrostatic precipitator is more than $24,000 per ton of PM removed. The applicant believes these costs are excessive.

The applicant also conducted an incremental cost effectiveness calculation to compare the existing cyclones/venturi scrubber system to the cyclones/venturi scrubber/ electrostatic precipitator system. The applicant estimates the annualized costs for the venturi scrubber as $463,435. Total annualized costs for the cyclones/venturi scrubber/electrostatic precipitator system would be $1,866,828. The applicant asserts that the control efficiency for the cyclones/venturi scrubber/electrostatic precipitator system would be 99.9%$^+$, which would emit approximately 6 tons of PM per year. Therefore, the applicant estimates the incremental cost as:

Incremental Costs = ($1,866,828 - $463,435) / (58 tons PM/year – 6 tons PM/year) > $26,000 per ton PM removed

The applicant believes the incremental cost difference between the two control options is excessive. The applicant comments that the existing mills with electrostatic precipitator/venturi scrubbers in place installed the electrostatic precipitators to regain compliance with the emissions standards. Cost effectiveness estimations were not required under these scenarios. In addition to the cost analysis, the applicant considered the following:

- Lime kilns are subject to a PM standard of 0.13 grains per dscf @ 10% O_2 when firing liquid fossil fuel as specified in NSPS Subpart BB.
- The No. 4 Lime Kiln is subject to an existing BACT standard for PM of 0.081 grains per dscf @ 10% O_2 as specified in Permit No. PSD-FL-171 (AC54-192551) issued on June 12, 1991.
- Lime kilns are subject to a PM standard of 0.064 grains per dscf @ 10% O_2 as specified in NESHAP Subpart MM.

- For lime kilns, the RBLC identifies previous BACT determinations for PM emissions in the range of 0.01 to 0.033 grains per dscf @ 10% O_2.

Although many of the RBLC BACT standards are based on control by an electrostatic precipitator, the applicant maintains that a high-energy wet venturi scrubber is an effective PM control technology. Therefore, based on the existing cyclones/venturi scrubber system, the applicant proposes to retain the current PM standard of 0.064 grains per dscf @ 10% O_2 and 29.73 lb/hour as BACT for the lime kiln, which is equivalent to the PM standard in NESHAP Subpart MM for lime kilns.

For visible emissions, the applicant indicated that the current standard is "less than 20% opacity". Although this is the Department's general visible emissions standard specified in Rule 62-296.320(4)(b)1, F.A.C., Permit No. PSD-FL-171 (AC54-192551) did not require adherence due to moisture interference. For a visible emissions observation of 20% opacity or more, the Department could require the permittee to conduct a special PM mass emissions tests. The applicant requests that this same protocol for visible emissions remain as previously established.

Department's Review

The Department does not endorse the applicant's cost analysis or equipment cost estimates. Although consideration is given to existing controls, the evaluation of new equipment should be based on the potential reductions from the lowest enforceable emissions rate and the control capabilities of the new system. The cost analysis should be based on the following assumptions: applicant's estimated annualized cost for an electrostatic precipitator of $1,403,393; a new controlled PM emissions rate of 4.65 lb/hour (99.8% reduction and 0.01 grains per dscf); and the current lowest controlled emissions rate of 0.064 grains per dscf @ 10% O_2 specified by NESHAP Subpart MM (29.7 lb/hour). This results in a cost effectiveness estimate of more than $12,000 per ton of PM removed by the proposed electrostatic precipitator. The revised cost effectiveness is about half of the applicant's estimate, but remains very high due to the existing controls. Although a detailed cost analysis was not conducted, the cost effectiveness for a baghouse would also be cost prohibitive due to the relatively low controlled emissions rate for the existing cyclones/venturi scrubber.

Based on a review of EPA's RBLC, a summary of PM BACT determinations since 1990 for similar lime kiln throughputs is shown below. The maximum lime production rate for the No. 4 Lime Kiln is 467 tons per day (TPD).

Facility/Location/Permit Issued	Status/Capacity	Control System	PM Limit	Basis
Weyerhaeuser - Flint River, GA May 2003	New 370 TPD	Electrostatic Precipitator	0.01 gr/dscf @ 10% O_2	Subpart MM (new unit)
Port Hudson, LA January 2002	Unit 1 Existing 340 TPD	Wet Scrubbers	25.76 lbs/hr	BACT
Port Hudson, LA January 2002	Unit 2 Existing 270 TPD	Wet Scrubbers	20.45 lbs/hr	BACT
Weyerhaeuser Company, MS September 1996	Existing 504 TPD	Electrostatic Precipitator	0.033 gr/dscf @ 10% O_2	BACT
Buckeye Florida, FL August 1996	Existing 750 TPD	Electrostatic Precipitator	20 lbs/hr	BACT
Williamette - Marlboro Mill, SC April 1996	New 450 TPD	Electrostatic Precipitator	0.033 gr/dscf @ 10% O_2	BACT
International Paper - FL (formerly Champion International) March 1994	Existing 500 TPD	Electrostatic Precipitator/ Venturi Scrubber/ Packed Column Mist Separator	10.90 lbs/hr	BACT
Gulf States Paper – AL January 1994	New 650 TPD	Electrostatic Precipitator	22 lbs/hr @ 10% O_2 (gas) 42 lbs/hr @ 10% O_2 (oil)	BACT

For comparison purposes, capacity of the No. 4 Lime Kiln is 996 TPD. Note that BACT standards have been set in terms of grains per dscf, lb/hour, or both. In general, the term "grains per dscf" is used for units controlled by an electrostatic precipitator. Correcting PM standards for the oxygen content is generally used for pure combustion sources.

Performance Test Date	Tested PM Emissions			
	grains/dscf @ 10% O_2	lb/hr	Process Rate, TPH	lb/ton processed
07/25/2006	---	14.50	38.6	0.38
09/08/2005	---	17.60	*37.4*	*0.47*
08/26/2004	0.027	11.50	*37.4*	*0.31*
02/26/2004	0.01	4.20	39.3	0.11
01/14/2003	0.033	11.94	*37.4*	*0.32*
07/03/2002	0.028	9.51	*37.4*	*0.25*
07/13/2001	0.029	10.77	*37.4*	*0.39*
04/12/2000	0.044	16.03	*37.4*	*0.43*
05/17/1999	0.03	7.20	34.4	0.21
05/12/1998	---	13.00	37.5	0.35
02/13/1997	---	17.48	36.0	0.49
03/30/1996	---	12.30	37.0	0.33
04/27/1995	---	18.30	*37.4*	*0.49*

PM emissions from the lime kiln should primarily be a function of the process rate of the material introduced to the kiln. The uncontrolled PM emissions rate in Table 10.2-1 of AP-42 for a lime kiln is provided as 56 lb/ton of air-dried unbleached pulp. Based on a plant capacity of 77 tons per hour of air-dried unbleached pulp, the estimated uncontrolled PM emissions rate is approximately 4312 lb/hour. The PM emission factor in Table 1.3-1 of AP-42 for residual oil combustion is 24.8 lb/1000 gallons of oil fired with a maximum sulfur content of 2.35% by weight. For the No. 4 Lime Kiln, this equates to approximately 23 lb/hour, which represents less than 1% of the predicted total uncontrolled PM emissions. So, the majority of PM emissions are lime dust from the process.

Based on data from the Department's ARMS database, the table summarizes the actual tested PM emissions rates from the existing cyclone/wet venturi scrubbing system installed on the No. 4 Lime Kiln. Annual tests are conducted at 90% to 100% of the maximum processing rate. Hourly mass emissions rates have been as high as 18.3 lb/hour, as low as 4.2 lb/hour, and averaged 12.6 lb/hour. For tests that identified the process rate, the table also shows a corresponding emissions rate in terms of "lb/ton of lime cake processed". The maximum processing rate of the kiln is 41.5 tons/hour of lime cake. For tests without a known process rate, the processing rate was assumed at 90% of the maximum (*37.4 TPH*) since tests are generally conducted at rates greater than 90%.

The Department intends to establish the draft BACT standards based on the rate of lime cake fed to the kiln. Assuming a margin of 25% above the maximum hourly emissions rate of 18.3 lb/hour, the corresponding emissions rates would be 22.9 lb/hour and 0.55 lb/ton of lime cake processed, which represents a 99% reduction from the estimated uncontrolled emissions. All of the tested emissions rates were less than 0.55 lb/ton of lime cake. At a maximum flow rate of 54,200 dscfm @ 10% oxygen, the equivalent PM emissions rate would be:

PM = (22.9 lb/hour) (7000 grains/lb) (hour/60 minutes) (minute/54,200 dscf @ 10% O_2) = 0.049 grains per dscf @ 10% O_2

This is approximately 75% of the current lowest emissions applicable standard of 0.064 grains per dscf @ 10% O_2 specified by NESHAP Subpart MM. Therefore, the Department establishes the following draft BACT standards based on the demonstrated capabilities of the existing control configuration, the actual tested emissions rates, and the maximum process rate of the lime kiln.

As determined by EPA Method 5 tests, PM emissions from the No. 4 Lime Kiln shall not exceed 0.55 lb per ton of actual material processed and 22.9 lb/hour based on the average of three test runs.

The draft standard is similar to the terms for PM standards established for Portland cement kilns, which are based on material feed rates to the preheater. The draft standard represents a control efficiency of greater than 99% for the existing cyclone/venturi scrubber system. Initial and annual stack tests shall be conducted at permitted capacity to demonstrate compliance with these standards. Permitted capacity is between 90% and 100% for the maximum processing rate of 41.5 tons/hour.

Moisture in the exhaust plume due to the wet scrubber interferes with an accurate determination of opacity. In lieu of an opacity standard, the draft permit requires the permittee to conduct the same continuous parametric monitoring that is required for the PM standard specified in NESHAP Subpart MM for existing lime kilns. Acceptable parametric ranges must be established for the scrubber pressure drop and liquid flow rate based on stack tests demonstrating compliance *with the PM BACT standards*. Parameters must be continuously monitored and recorded at least every 15 minutes and a three-hour block average determined.

NO_x Emissions - No. 4 Lime Kiln

Discussion of NOx Emissions and Available Control Technologies

In general, NO_X emissions from the lime kiln are a combination of thermal NO_X and fuel NO_X. Thermal NO_X is produced from a series of chemical reactions in which diatomic nitrogen and oxygen present in the combustion air dissociate in a high temperature combustion zone and react to form NO_X. Fuel NO_X is generated from nitrogen available in the fuel oil that is oxidized to NO_X. The spent lime cake and residual fuel oil are low in nitrogen content, so the primary NO_X mechanism for lime kilns is thermal NO_X.

Based on the BACT determinations listed in the RBLC since 1990, the following NO_X control technologies were identified for lime kilns: no controls, low-NO_X burners, efficient operations, good combustion control, and preventive maintenance. It is also possible that the following add-on NO_X control technologies could be applied to a lime kiln.

- *Selective Catalytic Reduction (SCR)*: SCR systems work by injecting ammonia into the exhaust gas stream and passing the exhaust across a catalyst bed to further the chemical NO_X reduction reaction. This system converts NO_X to elemental nitrogen, carbon dioxide, and water vapor. The temperature range for a conventional SCR catalyst is 550° to 750° F; however, new catalyst formations are available for temperatures of 1000° F. SCR systems can achieve NO_X reductions approaching 90%.
- *Selective Non-Catalytic Reduction (SNCR)*: SNCR systems work by injecting ammonia or urea into a high-temperature portion of the furnace or ductwork to convert NO_X to elemental nitrogen and water vapor. The optimum temperature range for an ammonia-based system is 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. SNCR systems can achieve NO_X reductions of 50% on some applications.
- *Low-NO_x Burners (LNBs)*: LNBs provide a stable flame that has several different zones. Typically, the first zone is primary combustion, the second zone is re-burn with fuel added to chemically reduce NO_X, and the third zone is final combustion in low excess air to prevent high temperatures. NO_X reductions vary from 20% to 50%.
- *Low Excess Air (LEA)*: Excess combustion air has been correlated to the amount of thermal NO_X generated. Limiting the net excess air can reduce the thermal NO_X produced. NO_X reductions vary from 0 to 30%.

Applicant's Proposal

SCR technology has not been applied to lime kilns due to the variable exhaust temperatures associated with the process. Further, the applicant believes that the optimum temperature range for the catalytic reaction is 575 to 750° F. A lime kiln typically operates in the range of 1600° F - 2700° F. Injected ammonia may also react with sulfur to form ammonium bisulfate, which has the potential to create a visible and/or detached plume. The lime may also react with the sulfur to form calcium sulfate. Ammonium bisulfate and calcium sulfate coatings, along with other dusts, may block the catalyst pores, which can reduce catalyst effectiveness and lead to premature failure. The SCR unit could be placed downstream of the wet scrubber to alleviate the catalyst blockage problem; however, the flue gas is approximately 170° F and would require a heat exchanger (i.e., an additional gas-fired duct burner) system to achieve the desired reaction temperature of greater than 575° F. SCR technology is not listed for lime kilns in the RBLC. The applicant does not believe SCR technology is feasible for lime kilns because it has not been demonstrated and due to concerns over premature catalyst failure.

Several difficulties preclude use of an SNCR system for control of NO_X emissions from a lime kiln. The correct temperature window of 1600° F to 2100° F occurs inside the rotating body of the kiln. Locating injection nozzles in such an area is not technically feasible at the present time and has not been attempted on any lime kiln. If kiln temperatures exceed 2,100° F, ammonia injected with the SNCR system will oxidize and form additional NO_X. Due to load fluctuations, it will be difficult to maintain the correct ammonia-to-NO_X molar ratio, which leads to the over injection of ammonia. Excess ammonia, known as ammonia slip, would be released directly to the atmosphere. Ammonia slip may also lead to the formation of ammonium salts, which can form a visible plume from the stack. Further, the formation of ammonia salts in the kiln could cause process downtime due to "ringing" effects on the kiln interior causing the buildup of materials. SNCR technology is not listed for lime kilns in the RBLC. The applicant does not believe SNCR technology is feasible for lime kilns because it has not been demonstrated and due to the technical issues discussed.

Although LNBs have been extensively tested and used in utility boilers and industrial furnaces, the transfer of this technology to lime processing has been met with difficulties. Burner flame properties are critical to the quality control and calcining process to convert a high percentage of mud to re-burned lime in the lime kiln. The burner flame shape and properties have a dramatic effect on the calcining efficiency. Poor efficiency increases energy usage and decreases the calcining capacity of the kiln. Due to these technical complexities, the conversion of a standard lime kiln burner to low NO_X design is not yet technically feasible. Further, in a BACT determination for the Weyerhaeuser Mill, Georgia stated that there are no commercially available LNBs on the market for a lime kiln application. The applicant does not believe that LNBs are feasible or available for lime kilns.

Excess combustion air has been correlated to the amount of thermal NO_X generated. Limiting the net excess air can reduce the thermal NO_X produced. NO_X reductions vary from 0 to 30%. The current kiln system minimizes oxygen levels to approximately 4% to 6%.

NO_X formation can be minimized by proper kiln design and operation. Generally, emissions are minimized by properly controlling air in the air/fuel injection zones to maintain kiln temperatures at the lower end of the desired range. Ideally, maintaining a low-oxygen condition near fuel injection points approaches an off-stoichiometric, staged combustion process. For the No. 4 Lime Kiln, the flue gas oxygen content is low at 4% to 6% by volume when compared to the reference oxygen content of 10% by volume specified for other emissions standards in NESHAP Subpart MM. Good combustion practices and low excess air is technically feasible and currently in use for this unit.

Based on EPA's RBLC, NO_X BACT determinations for lime kilns since 1990 are in the range of 100 to 340 ppmvd @ 10% O_2 and are based on: no controls, LNBs, efficient operations, good combustion control, and preventive maintenance. There is only one entry listing LNBs for two small existing lime kilns (8.4 tons/hour of lime produced) firing recycled fuel oil with a NO_X standard of 3.5 lb/ton of lime produced. However, the current NO_X standard for the No. 4 Lime Kiln is 290 ppmvd @ 10% O_2 and 50.3 lb/hour, which is approximately 2.6 lb/ton of lime produced.

The current NO_X standard is at the high end of previous BACT determinations in EPA's RBLC. Based on tests, actual NO_X emissions were 33.7 lb/hour in 2004 and 17.9 lb/hour in 2005. Therefore, the applicant proposes reducing the NO_X standard from 290 to 175 ppmvd @ 10% O_2 with an equivalent mass emissions rate of 67.9 lb/hour at the increased flue gas flow rate.

Department's Review

Performance Test Date	Tested NO_X Emissions lb/hr
3/30/96	40.0
2/13/97	27.7
5/13/98	23.0
5/17/99	41.0
4/12/00	34.2
7/13/01	32.3
7/3/02	18.9
1/14/03	32.0
2/26/04	33.7
9/8/05	17.9
7/25/06	16.8

The table summarizes the results of annual tests conducted at 90% to 100% of the maximum capacity. As shown, the hourly mass emissions rates have been as high as 41.0 lb/hour, as low as 16.8 lb/hour, and averaged 28.9 lb/hour. Assuming permitted capacity, the range of NO_X emissions is approximately 43 to 106 ppmvd @ 10% O_2, which is relatively low for a calcining kiln. The Department is not aware of any lime kilns with SCR or SNCR systems installed; however, these systems are considered technically feasible given adequate temperature requirements. Neither is the Department aware of any low-NO_X kiln burners that will deliver significantly lower NO_X emissions levels.

Based on actual emissions from the No. 4 Lime Kiln and the nature of this project, it is likely that such add-on controls would be cost prohibitive. The Department also considers that the nature of the $2 million project is not to increase kiln production, but for major repair of the hot-end shell section and replacement of existing coolers. Therefore, the Department establishes the following draft BACT standards based on good combustion design and practices for the No. 4 Lime Kiln.

> As determined by EPA Method 7E, NO_X emissions shall not exceed 140.0 ppmvd @ 10% O_2 and 54.2 lb/hour based on the average of three test runs.

The standard is based on the demonstrated NO_X levels for the No. 4 Lime Kiln as well as the established BACT standards for similar units. Compliance with the NO_X standards shall be demonstrated by conducting initial and annual stack tests at permitted capacity.

CO and VOC Emissions - No. 4 Lime Kiln

Discussion of CO and VOC Emissions and Available Control Technologies

CO and VOC emissions are formed due to incomplete combustion of the fuels. The main options for reducing CO and

VOC emissions are thermal oxidation, catalytic oxidation and combustion modifications. Thermal oxidizers would rarely be used to control kiln exhausts because it would require high fuel firing rates to achieve the necessary oxidizing temperatures. In general, thermal oxidizers are used when there are high concentrations of organic compounds. For relatively dust-free exhausts such as gas turbines, oxidation catalysts may be used to reduce CO and VOC emissions. Oxidation catalysts typically operate at temperatures between approximately 600° F and 1100° F. Depending on the specific pollutants, inlet concentrations and other factors, reductions of more than 90% are possible.

Applicant's Proposal

The applicant believes that thermal incineration is cost prohibitive due to the additional fuel requirements to achieve and maintain the necessary destruction temperature. The applicant does not believe the use of catalytic oxidation is appropriate due to the potential for premature failure of the catalyst from poisoning (metals in residual oil) and plugging/fouling (high dust loading). Therefore, post-combustion controls do not seem feasible.

Minimizing the formation of CO emissions from lime kilns 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). Due to the long residence time and high temperatures in the lime kiln, CO emissions are low and have been verified by stack testing.

Based on EPA's RBLC database for CO BACT determinations from lime kilns since 1990, the following control technologies were identified: good combustion practices, kiln design, proper combustion techniques, and no controls. The RBLC data shows previous CO BACT determinations ranging from 45 to 1400 ppmvd @ 10% O_2. For the No. 4 Lime Kiln, the current CO standard is 69 ppmvd @ 10% O_2, which is at the low end for previous CO BACT determinations. Therefore, the applicant proposes to retain the current standard of 69 ppmvd @ 10% O_2 with an equivalent mass emissions rate of 16.3 lb/hour at the increased flow rate.

Based on EPA's RBLC database for VOC BACT determinations from lime kilns since 1990, the following control technologies were identified: good combustion practices, kiln design, proper combustion techniques, venturi scrubber using fresh water, and no controls. The RBLC data shows previous BACT determinations ranging from 25 to 185 ppmvd @ 10% O_2 for VOC emissions. For the No. 4 Lime Kiln, the current VOC standard is 185 ppmvd @ 10% O_2, which is at the high end for previous VOC BACT determinations. Therefore, the applicant proposes to reduce the VOC standard to 70 ppmvd @ 10% O_2 with an equivalent mass emissions rate of 9.4 lb/hour (determined as methane).

Department's Review

Test Date	CO, lb/hour	VOC, lb/hour
3/30/96	1.1	0.3
2/13/97	1.1	1.3
5/13/98	5.3	2.8
5/17/99	1.4	0.3
4/12/00	3.3	1.1
7/13/01	2.1	0.9
7/3/02	5.6	0.6
1/14/03	1.8	0.6
2/26/04	1.4	0.6
9/8/05	2.0	0.6
7/25/06	7.0	0.1

Based on the Department's ARMS database, CO emissions range from 1.1 to 7.0 lb/hour during the annual stack tests conducted at permitted capacity. Similarly, VOC emissions ranged from 0.1 to 2.8 lb/hour. The low emissions levels are expected due to the kiln temperatures and long residence times. Thermal and catalytic oxidation is technically feasible, but impractical for this application and would result in prohibitive costs due to currently low CO and VOC emissions. Therefore, the Department establishes the following draft BACT standards based on good combustion design and practices.

- As determined by EPA Method 10, CO emissions from the lime kiln shall not exceed 69.0 ppmvd @ 10% O_2 and 16.3 lb/hour based on the average of three test runs.
- As determined by EPA Method 25A, VOC emissions from the lime kiln shall not exceed 70.0 ppmvd @ 10% O_2 and 9.4 lb/hour (THC determined as methane) based on the average of three test runs.

The standards are based on the demonstrated CO and VOC levels for the No. 4 Lime Kiln as well as the established BACT standards for similar units. Compliance with the CO and VOC standards shall be demonstrated by conducting initial and annual stack tests at permitted capacity. If consecutive annual tests show compliance at 50% of the standard or less, the test frequency will be reduced to testing prior to renewal of the operation permit.

5. BACT ANALYSIS - NO. 4 RECOVERY BOILER (EU-018)

The No. 4 Recovery Boiler (EU-018) fires black liquor solids (BLS) as the primary fuel at a maximum permitted firing rate of 210,000 lb/hour of BLS. Based on an as-fired heating value of 6410 Btu per lb of BLS, the maximum heat input rate is 1346 MMBtu per hour. Residual fuel oil containing a maximum sulfur content of 2.35% by weight is fired as a startup and supplemental fuel. The firing of residual oil is restricted to no more than 7,860,640 gallons per consecutive 12 months, which is less than 10% of the maximum annual heat input. At permitted maximum capacity, the exhaust flow rate is 294,000 dscfm @ 8% O_2. There is no restriction on the hours of operation. The recovery boiler will remain subject to all existing emissions standards. The project is subject to PSD preconstruction review for emissions of CO, NO_X, PM, and VOC. The following table summarizes the applicant's estimated of potential emissions changes for the No. 4 Recovery Boiler due to the project.

Pollutant	Emissions, Tons per Year		
	Baseline	Future Potential	Change
CO	1249.3	2245.6	+ 996.3
NO_X	473.2	738.1	+ 264.9
PM	134.7	331.1	+ 196.4
PM_{10}	101.0	248.3	+ 147.3
VOC	9.5	92.0	+ 82.5

The applicant notes that actual emissions may not increase as a result of the project. As shown in the above table, the project will increase emissions of CO, NO_X, PM, and VOC; therefore, BACT determinations are required for these pollutants.

PM Emissions – No. 4 Recovery Boiler

PM emissions from the recovery boiler are currently controlled by an electrostatic precipitator. Removal of the entrained ash is crucial to overall material recovery as it is reused in the process.

Applicant's Proposal

Common control equipment for removing PM includes baghouses, electrostatic precipitators, and wet scrubbers. Baghouses typically consist of a series of hanging, fine mesh bags and can be designed for removal efficiencies greater than 99%. Electrostatic precipitators charge particles for collection on large hanging plates with removal efficiencies greater than 99%. High-energy wet scrubbers are effective in removing particulate matter with control efficiencies approaching 98%. As reflected in EPA's RBLC, nearly all recovery boilers at pulp and paper mills in the United States use electrostatic precipitators to control particulate matter emissions.

The applicant selects an electrostatic precipitator as the top control option. Since an electrostatic precipitator already controls PM emissions from the No. 4 Recovery Boiler, no additional controls are proposed. Based on the existing design, the applicant proposes a BACT standard of 0.030 grains per dscf @ 8% O_2. This is the current standard for the recovery boiler as established in Permit No. PSD-FL-226 issued on September 21, 1995. A review of EPA's RBLC identifies BACT limits ranging from 0.021 to 0.15 grains per dscf for recovery boilers. Therefore, the proposed standard is at the low end of the range for previous BACT determinations. For comparison purposes, EPA promulgated the following standards for recovery boilers:

- NSPS Subpart BB: PM $\leq$ 0.044 grains per dscf @ 8% O_2; and
- NESHAP Subpart MM: PM $\leq$ 0.044 grains per dscf @ 8% O_2 as a surrogate for reducing metal HAP emissions.

Also, the applicant requests retaining the current visible emissions standard of 20% opacity (normal operation) except for up to 6% of the opacity readings collected during a calendar quarter no greater than 35%, which is standard under 40 CFR 63, NESHAP Subpart MM. Compliance will be verified by the existing continuous opacity monitoring system (COMS).

Department's Review

Compliance tests conducted on the existing recovery boiler over the last 10 tears show PM emissions ranging from 0.004 to 0.030 grains per dscf @ 8% O_2. The applicant's proposed standard of 0.030 grains per dscf @ 8% O_2 is equivalent to

0.0036 lb PM per ton of air-dried unbleached pulp. The uncontrolled PM emission factor from Table 10.2-1 in AP-42 is 180 lb per ton of per ton of air-dried unbleached pulp. So, the estimated control efficiency of the existing electrostatic precipitator is greater than 99%. The Department agrees that an electrostatic precipitator is a top control system for the recovery boiler process. Therefore, the Department establishes the following draft BACT PM standards based on the existing electrostatic precipitator.

- As determined by EPA Method 5 or 29, PM emissions shall not exceed 0.030 grains per dscf @ 8% O_2 and 75.6 lb/hour based on the average of three test runs.
- Once the ESP is placed in service during startup of the recovery boiler, visible emissions shall not exceed 20% opacity as determined by COMS and EPA Method 9.

Compliance with the PM standard shall be demonstrated by conducting initial and annual stack tests. Compliance with the opacity standard shall be demonstrated by the existing COMS and EPA Method 9. The Department notes that Permit No. PSD-FL-171 (AC54-192550) issued on June 12, 1991 established a BACT standard for visible emissions of no more than 20% opacity for the existing recovery boiler.

NO_X Emissions – No. 4 Recovery Boiler

In general, NO_X emissions from recovery boilers are a combination of thermal NO_X and fuel NO_X. Thermal NO_X is produced from a series of chemical reactions in which diatomic nitrogen and oxygen present in the combustion air dissociate in a high temperature combustion zone and react to form NO_X. Fuel NO_X is generated when nitrogen available in the BLS or fuel oil is oxidized to NO_X. Due to moderate combustion zone temperatures (< 1500° F) and staged combustion techniques, thermal NO_X from a recovery boiler is not believed to be the significant portion of overall NO_X emissions. However, it is possible for higher temperatures in the combustion zone to oxidize more of the available fuel nitrogen to NO_X. In general, NO_X emissions from recovery boilers are relatively low (< 125 ppmvd) due to moderate furnace temperatures and low nitrogen content of BLS (< 0.10% by weight). For comparison, the nitrogen content of residual oil ranges from 0.2 to 0.5% by weight.

Applicant's Proposal

The applicant identified the following available NO_X controls.

- *Selective Catalytic Reduction (SCR)*: SCR systems work by injecting ammonia into the exhaust gas stream and passing the exhaust across a catalyst bed to further the chemical NO_X reduction reaction. This system converts NO_X to elemental nitrogen and water vapor. The optimum temperature range for a conventional SCR catalyst is 550° to 750° F; however, new catalyst formations are available for temperatures of 1000° F. SCR systems can achieve NO_X reductions approaching 90%.
- *Selective Non-Catalytic Reduction (SNCR)*: SNCR systems work by injecting ammonia or urea into a high-temperature portion of the furnace or ductwork to convert NO_X to elemental nitrogen and water vapor. The optimum temperature range for an ammonia-based system is 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. SNCR systems can achieve NO_X reductions of 50% on some applications.
- *Overfire Air (OFA)*: The recovery boiler currently stages combustion air with a 3-level OFA 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 added in two more stages to complete combustion of the fuel while maintaining the low temperatures that will prevent thermal NO_X formation. OFA systems can reduce NO_X emissions by 20% to 50%.
- *Low-NO_X Burners (LNBs)*: LNBs provide a stable flame that has several different zones. Typically, the first zone is primary combustion, the second zone is re-burn with fuel added to chemically reduce NO_X, and the third zone is final combustion in low excess air to prevent high temperatures. NO_X reductions vary from 20% to 50%.
- *Flue Gas Recirculation (FGR)*: Recirculation of cooler flue gas reduces the 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. NO_X reduction potential varies from 15% to 20%.

- *Low Excess Air (LEA)*: Excess combustion air has been correlated to the amount of thermal NO_X generated. Limiting the net excess air can reduce the thermal NO_X produced. NO_X reductions vary from 0 to 30%.

An SCR system is recognized as the top control option for reducing NO_X 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 BLS as the primary fuel, which results in high particulate matter loading of boiler exhaust. If the catalyst were installed prior to the electrostatic precipitator, the catalyst would quickly plug and foul due to deposits from particles in the flue gas. For this reason, the applicant does not believe installation of an SCR system prior to the electrostatic precipitator is technically feasible.

If the catalyst were installed after the existing electrostatic precipitator, the exhaust gas would have to be heated from ~425° F to ~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 such 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 cost for an SCR system of nearly $16 million and total annualized cost of nearly $7.5 million. The cost effectiveness of an SCR system is estimated at nearly $17,600 per ton of NO_X removed based on actual NO_X emissions (2004 – 2005) of 473.2 tons per year and 90% SCR control efficiency. The applicant rejects SCR due to the technical challenges and excessive costs.

SNCR is the next top control option for reducing NO_X emissions. The applicant believes that an SNCR system is not technically feasible for a recovery boiler, which is a complete chemical reaction process. Any disruption of the delicate balance of chemistry within the boiler could potentially damage it, reduce unit availability, impact the quality of the product, or otherwise 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 NO_X control option for recovery boilers. Based on these discussions, the applicant rejects SNCR because it is not commercially available for recovery boilers.

Of the remaining control options, staged combustion with OFA is the next likely control option. The existing recovery boiler currently employs staged combustion with primary, secondary and tertiary OFA. The applicant proposes to add a fourth level (quaternary) of OFA to further stage combustion air and inhibit NO_X formation. A well-designed OFA and control system promotes uniform combustion, which removes hot and cold spots in the combustion zone. OFA systems are routinely employed to reduce NO_X 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 RBLC shows previous 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 for the supplemental firing of natural gas. 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 No. 4 Recovery Boiler is 80 ppmvd @ 8% O_2 and 168.5 lb/hour. The vendor guarantees NO_X emissions in the range of 78 to 90 ppmvd @ 8% O_2 for the modified OFA system with a fourth level of OFA. This is based on a 75% solids content of the BLS, which is the proposed level once the new crystallizer is added. The current limit is within the vendor guarantee and at the low end of the previous NO_X BACT determinations for recovery boilers. Considering a reduction in CO emissions with the improved OFA system, the applicant proposes to retain the current NO_X limit of 80 ppmvd @ 8% O_2.

Department's 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 $17,600 per ton of NO_x removed was based on actual NO_X emissions and not potential NO_x emissions. However, the cost effectiveness would still be more than $10,000 per ton of NO_X removed assuming the applicant's estimated annualized cost of $7.5 million, potential NO_X emissions of 738 tons per year (based on 80 ppmvd), and 90% reduction. SCR will not be considered due to the high estimated costs, which are partially due to the relatively low NO_X emissions from this industrial boiler.

The Department found only the following reference to employing SNCR on a recovery boiler in Sweden (Sodra Skogsagma), "... Demonstrations of SNCR, in addition to municipal waste incinerators and wood- and coal-fueled district heating plant boilers, included a pulp and paper mill Kraft recovery boiler, where a 60% reduction from uncontrolled emissions of 60 ppm was attained.[1]" The Department contacted Fuel-Tech, an SNCR vendor, and discussed the technology for recovery boilers. The vendor could not identify any known installations of SNCR on a recovery boiler, but was aware of the performance test in Sweden. That test was conducted over only a few hours and then the equipment removed. The vendor was not aware of any long term performance tests.

Based on the discussions with SNCR vendors, the Department was unable to determine that SNCR is commercially available and demonstrated for recovery boilers at this time. A review of EPA's RBLC shows that previous NO_X BACT determinations have relied upon combustion control techniques. The Department's BACT determination will be based on adding a fourth level of combustion air.

In September of 1995, the Department issued Permit No. PSD-FL-226 (AC54-266676) for this unit with a NO_X BACT standard of 80 ppmvd @ 8% O_2. For reference, this is approximately 0.13 lb/MMBtu of heat input. A review of EPA's RBLC shows BACT standards ranging from 70 to 210 ppmvd @ 8% O_2. For the existing recovery boiler, actual test results for the No. 4 Recovery Boiler show NO_X emissions ranging from 48 to 74 ppmvd @ 8% O_2. The additional solids content of the BLS may result in higher temperatures, but the improved OFA system should compensate by further staging combustion to inhibit additional NO_X formation. The Department's draft NO_X BACT determination is:

> As determined by data collected from the required CEMS, NO_X emissions from the recovery boiler shall not exceed 80.0 ppmvd @ 8% O_2 and 168.5 lb/hour based on a 30-day rolling average, excluding periods of startup and shutdown.

The new CEMS-based standard will allow the continuous demonstration of compliance and ensure the use of good combustion practices. The new standard will replace the previous NO_X standard and is believed to be more stringent due to the continuous compliance demonstration. Although NO_X emissions should be low during startup and shutdown, the standard excludes data collected during these periods because emissions rely on staged combustion, which is not in full effect during these periods.

CO and VOC Emissions – No. 4 Recovery Boiler

CO and VOC emissions are formed due to incomplete combustion of the fuels. The main options for reducing CO and VOC emissions are thermal oxidation, catalytic oxidation and combustion improvements. CO and VOC emissions can be oxidized to carbon dioxide either thermally or catalytically. Thermal oxidizers are capable of control efficiencies of more than 90% at operating temperatures approaching 1800° F. However, thermal oxidizers are not considered for the control of boiler exhausts due to the large fuel requirements necessary to maintain the high oxidizing temperatures. For low-dust exhausts, oxidation catalysts may be used to further the reduction of CO and VOC emissions at lower operating temperatures (600° F to 1100° F). Oxidation catalysts are capable of reductions greater than 90% depending on the specific pollutants and inlet concentrations.

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 (adequate residence time at a sufficient combustion temperature). For the recovery boiler, good combustion includes adequate control of the ratio of BLS to combustion air in the furnace. In addition, staged combustion with overfire air promotes uniform mixing and complete combustion of the fuel. Minimizing the formation of CO/VOC emissions from boilers is generally achieved by ensuring efficient combustion.

<u>Applicant's Proposal</u>

Oxidation catalysts are sensitive to poisoning, blinding, plugging, fouling, and erosion. If installed before the electrostatic precipitator, particulate matter would soon erode, plug and foul the catalyst. If installed after the electrostatic precipitator, residual particles may still be sufficient to build-up and clog catalyst pore spaces and reduce effectiveness. In addition, BLS contain significant amounts of sodium (18.7% by weight), potassium (1.09% by weight), and 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 RBLC identifies the following CO and 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 good combustion design and practices. The applicant

[1] "White Paper on Selective Non-Catalytic Reduction", Institute of Clean Air Companies, Inc., May 2000

rejects an oxidation catalyst as technically infeasible for a recovery boiler due to poisoning from flue gas contaminants.

The existing No. 4 Recovery Boiler is subject to CO standards of 800 ppmvd @ 8% O_2 based on a three-hour average and 400 ppmvd @ 8% O_2 based on a 24-hour average, which were established as BACT in Permit No. PSD-FL-226 (AC54-266676) issued on September 21, 1995. EPA's RBLC shows previous CO BACT determinations for recovery boilers ranging from 200 to 3000 ppmv. These are case-by-case determinations and depend on the associated averaging period, age of the boiler, and OFA system. At Georgia-Pacific's mills, recovery boilers and other industrial boilers 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. Actual test data for the existing No. 4 Recovery Boiler indicates that CO emissions range from 102 to 756 ppmvd @ 8% O_2. The applicant proposes to retain these current CO emission limits based on an improved overfire air system and good combustion control.

The existing No. 4 Recovery Boiler is subject to VOC standards of 0.30 lb/ton of BLS (~ 60 ppmvd @ 8% O_2) and 31.5 lb/hour established as BACT in Permit No. PSD-FL-226 (AC54-266676) issued on September 21, 1995. Review of EPA's RBLC 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 lb/ton of BLS (~2 to 16 ppmvd @ 8% O_2, respectively). The applicant proposes a VOC emissions limit 0.20 lb/ton of BLS based on an improved OFA system and good combustion control.

Department's CO/VOC BACT Reviews

The Department is unaware of any cases where either thermal or catalytic oxidation was required for the control of CO and/or VOC emissions from recovery boilers firing BLS. The applicant proposes to retain the current CO standards of 800 ppmvd @ 8% O_2 based on a three-hour average and 400 ppmvd @ 8% O_2 based on a 24-hour average. However, the applicant has relied on short-term stack tests to demonstrate compliance with these standards. For comparison, NESHAP Subpart DDDDD establishes a CO standard of 400 ppmv based on a 30-day rolling CEMS average to ensure good combustion and serve as a surrogate for low organic HAP emissions. The Department does not consider an oxidation catalyst appropriate for the control of CO and VOC emissions from the recovery boiler due to concerns with catalyst poisoning and expected high costs to control relatively low emissions levels. Therefore, the Department accepts the proposed modification to add a fourth level of OFA as good combustion design and practices.

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 three-hour test. Of the 15 tests reported, 11 test averages are below 400 ppmvd. According to the application, there is an optimum operating level for the BLS-to-air ratio. However, test results actually indicate a poor relationship between this ratio and CO emissions, possibly due to the manual control of the OFA system. The Department believes that CO emissions are controllable on a long-term average basis as provided by the industrial boiler MACT standard. Therefore, the Department establishes the following draft BACT standards.

> For the initial 180 calendar days after certifying the CEMS, CO emissions from the recovery boiler shall not exceed 800 ppmvd @ 8% O_2 and 1025.4 lb/hour based on a 30-day rolling CEMS average, excluding periods of startup and shutdown. Thereafter, CO emissions from the recovery boiler shall not exceed 400 ppmvd @ 8% O_2 and 512.7 lb/hour based on a 30-day rolling CEMS average, excluding periods of startup and shutdown.

The new CEMS-based standard will allow the demonstration of continuous compliance, ensure the use of good combustion practices, and provide useful data for the operator controlling the system. The purposes of the initial standard is to provide sufficient time for the operators to gain experience and establish good operating practices with the new four-level OFA system. The new standard will replace the previous CO standards and is believed to be more stringent due to the continuous compliance demonstration.

For the No. 4 Recovery Boiler, the applicant proposes VOC standards of 0.20 lb/ton of BLS and 21.0 lb/hour. Test data from the Department's ARMS database shows actual VOC emissions ranging from 0.01 to 0.083 lb/ton of BLS. Of the 14 tests submitted, all have been below 0.10 lb/ton BLS. The addition of a fourth level of OFA is intended to provide improved combustion control. In addition, low CO emissions generally mean low VOC emissions. Therefore, the Department establishes the following draft BACT standards.

> As determined by EPA Method 25A, VOC emissions shall not exceed 0.20 lb/ton of BLS and 21.0 lb/hour (THC determined as methane) based on the average of three test runs.

Compliance with the VOC standards shall be demonstrated by conducting an initial stack test. Because emissions are expected to be low and the CO CEMS will ensure efficient combustion, subsequent tests shall be conducted prior to renewal of the operation permit or when the Department requests a special test pursuant to Rule 62-297.310(7)(b), F.A.C. The CO standard serves as a surrogate standard for VOC.

6. OTHER PERMIT CONDITIONS

Previous Air Construction Permits

This permit supplements all previous permits issued for the affected emissions units. The conditions of this permit satisfy the applicable requirements for the emissions increases related to the project. These conditions supersede corresponding similar conditions specified in previous air construction permits. However, if not specifically regulated by this permit, other standards and permit requirements from previous air construction permits remain valid. The affected emissions units remain subject to all applicable standards and regulations as regulated by the Title V air operation permit.

No. 4 Power Boiler (EU-014)

The No. 4 Power Boiler is not currently in operation. Emissions decreases from the permanent shutdown of this unit were used in the PSD netting analysis to avoid PSD preconstruction review for SAM, SO_2, and TRS emissions. Therefore, the draft permit requires the permanent shutdown of the No. 4 Power Boiler.

No. 5 Power Boiler (EU-015)

<u>Existing Applicable Requirements</u>

The draft permit establishes a NO_X standard of 0.185 lb/MMBtu of heat input and 71.1 lb/hour to avoid PSD review pursuant to Rule 62-212.400(12), F.A.C. Unless otherwise specified by this permit, the No. 5 Power Boiler also remains subject to the following existing applicable requirements, which are specified in the current Title V air operation permit.

- Rule 62-296.404, F.A.C. for Kraft Pulp Mills;
- Rule 62-296.405, F.A.C. for Fossil Fuel Steam Generators with More than 250 MMBtu per hour of Heat Input;
- 40 CFR 63, NESHAP Subpart S for Kraft Pulp Mills; and
- 40 CFR 63, NESHAP Subpart DDDDD for Industrial Boilers.
- On July 2, 2004, the Department issued Permit No. 1070005-024-AC as a Pollution Control Project (PCP) pursuant to Rule 62-212.400(2)(a)2.b, F.A.C. That permit specified the strategy for complying with the applicable requirements of the MACT standards in NESHAP Subpart S in 40 CFR 63. That permit authorizes the No. 5 Power Boiler to destroy dilute non-condensable gases (DNCGs) from the high-volume, low-concentration (HVLC) system, which include emissions from brown stock washers, pressure knotters, the bleach plant pre-washer, the oxygen delignification system, and softwood/hardwood high density storage tanks. The DNCGs are introduced with the primary fuel, directed into the flame zone, or added with the combustion air. Optionally, the DNCGs may also be directed to the No. 4 Combination Boiler, which shares common permit conditions with the No. 5 Power Boiler. Permit No. 1070005-024-AC limits SO_2 emissions to 82.6 lb/hour and 236.3 tons per year from the destruction of DNCGs in any combination of the No. 4 Combination Boiler and the No. 5 Power Boiler. This current permitting action does not affect the previous authorization for destroying DNCGs.

<u>Discussion of PM Emissions and Testing</u>

The No. 5 Power Boiler is subject to Rule 62-296.405, F.A.C. because it fires fossil fuel at a rate of more than 250 MMBtu per hour of heat input. After conversion to natural gas, this unit will only be subject to the standards in this rule for visible emissions, PM and the requirement to monitor the ambient effects of SO_2 emissions as required by the Department. The PM standard is 0.1 lb per MMBtu of heat input. Natural gas contains negligible amounts of sulfur and ash, is efficiently combusted in a boiler, and is expected to result in PM emissions of less than 10% of the standard specified in this rule. For these reasons, the applicant proposes to remove the existing electrostatic precipitator used to remove ash generated from the combustion of residual fuel oil. The applicant proposes to use the existing electrostatic precipitator to reduce PM emissions from the No. 4 Combination Boiler.

In accordance with an alternate sampling procedure (ASP No. 97-B-01) dated March 17, 1997, the Department determined that PM testing is not required for boilers when firing natural gas. The firing of natural gas and compliance with the opacity standard is sufficient to demonstrate compliance with the PM standard. In accordance with Rule 62-297.310(7)(b), F.A.C., the Department may require special compliance tests if it has good reason to believe that the PM standard is being violated.

No. 4 Lime Kiln (EU-017)

Existing Applicable Requirements

Unless otherwise specified by this permit, the No. 4 Lime Kiln remains subject to the following existing applicable requirements, which are specified in the current Title V air operation permit.

- Rule 62-296.404, F.A.C. for Kraft Pulp Mills;
- 40 CFR 63, NESHAP Subpart S for Kraft Pulp Mill; and
- Permit No. PSD-FL-171.

New Requirements Requested by Applicant

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 following limitations to avoid PSD preconstruction review for SO_2 and TRS emissions.

- The maximum sulfur content of oil is 2.35% by weight.
- No more than 8,173,080 gallons of oil shall be fired during any consecutive 12 months.
- As determined by the existing CEMS, TRS emissions shall not exceed 25.1 tons per year based on a 12-month rolling CEMS total.

No. 4 Recovery Boiler (EU-018)

Existing Applicable Requirements

Unless otherwise specified by this permit, the No. 4 Recovery Boiler remains subject to the following existing applicable requirements, which are specified in the current Title V air operation permit.

- Rule 62-296.404, F.A.C. for Kraft Pulp Mills;
- NSPS Subpart BB in 40 CFR 63 for Recovery Combustion Sources at Kraft Pulp Mills;
- NESHAP Subpart MM in 40 CFR 63 for Recovery Combustion Sources at Kraft Pulp Mills; and
- Permit Nos. PSD-FL-171 and PSD-FL-226.

New Requirements Requested by Applicant

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 following limitations to avoid PSD preconstruction review for SO_2 and TRS emissions.

- The maximum sulfur content of oil is 2.35% by weight.
- No more than 7,860,640 gallons of oil shall be fired during any consecutive 12 months. (This limits oil firing to an annual capacity factor of less than 10% of the total heat input rate to the unit. It represents less than 17% of the maximum annual firing capabilities of the oil burners.)
- As determined by data collected from the existing CEMS, TRS emissions shall not exceed 34.2 tons per year based on a 12-month rolling CEMS total.
- As determined by data collected from the existing CEMS, SO_2 emissions shall not exceed 153.9 tons per year based on a 12-month rolling CEMS total.

No. 4 Combination Boiler

The PSD netting analysis included the project to modify the No. 4 Combination Boiler. Emissions increases from the No. 4 Combination Boiler were included in the required air quality analysis for this project. In addition, Project No. 1070005-045-AC will determine BACT for CO, NO_X, PM, and VOC from the No. 4 Combination Boiler. The pending project is based on the following oil firing restrictions: residual oil with a maximum sulfur content of 2.35% by weight; and a limit of 5.1 million gallons of oil fired during any consecutive 12 months.

- The maximum sulfur content of oil is 2.35% by weight.
- No more than 5,100,000 gallons of oil shall be fired during any consecutive 12 months. (This limits oil firing to an annual capacity factor of less than 19% of the total heat input rate to the unit. It represents approximately 20% of the maximum annual firing capabilities of the oil burners.)

7.0 AIR QUALITY ANALYSIS

Introduction

CO, NO_2, PM_{10} and VOC are PSD pollutants subject to the preconstruction review requirements for this project. CO, NO_2, and PM_{10} are criteria air pollutants with national and state ambient air quality standards (AAQS), significant impact levels, and de minimis preconstruction monitoring concentrations. In addition, NO_2 and PM_{10} have additional requirements for PSD increments. For the criteria pollutant ozone, VOC emissions are reviewed for significant impact levels and de minimis preconstruction monitoring concentrations. Therefore, the following analyses were required for this project.

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

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The significant impact analysis, PSD increment analysis, and AAQS analysis depend on air quality dispersion modeling carried out in accordance with EPA and Department guidelines.

Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring data is required for all significant PSD pollutants to determine existing ambient concentrations unless exempt by rule or the data requirements can be satisfied otherwise. Projects may be exempt from the requirement to develop site-specific preconstruction monitoring data if one of the following conditions is met: the maximum predicted ambient impact from the emissions increase due to the project is less than the corresponding regulatory de minimis ambient concentration; or, the existing ambient concentration is less than the corresponding regulatory de minimis ambient concentration. No de minimis ambient concentration is provided for ozone. Instead the net VOC emissions increase is compared to a de minimis annual emission rate of 100 tons per year.

Whether or not preconstruction ambient monitoring is required, it may be necessary to determine existing ambient background concentrations for each significant PSD pollutant subject to an AAQS. Ambient background concentrations represent the air quality impacts of all sources not included in the modeling analysis. The ambient background concentrations are added to the ambient impacts from modeled sources to determine total ambient impacts. Ambient background concentrations may be determined from the required preconstruction site-specific ambient air quality monitoring data or from existing representative ambient monitoring data collected from nearby qualified monitoring stations.

The following table compares the maximum predicted air quality impacts from the project with the regulatory de minimis concentrations.

MAXIMUM PREDICTED AIR QUALITY IMPACTS FROM PROJECT COMPARED TO THE REGULATORY DE MINIMIS CONCENTRATIONS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**De Minimis Concentration ($\mu g/m^3$)**	**Impact Greater than De Minimis? (Yes/No)**
PM_{10}	24-hr	12	10	Yes
CO	8-hr	79	575	No
NO_2	Annual	2	14	No
VOC	Annual Emissions Rate	389 tons/year	100 tons/year	Yes

As shown in the table, CO and NO_2 impacts are predicted to be less than the regulatory de minimis levels and preconstruction monitoring is not required for these pollutants. Because PM_{10} and VOC emissions are predicted to be greater than the regulatory de minimis levels, preconstruction monitoring data is required for these pollutants. Although exempt from preconstruction monitoring requirements, it will be necessary to determine existing ambient background concentrations for NO_2. To satisfy the ambient monitoring data requirements, the applicant proposes to use the following representative data collected from nearby stations that are part of the state's monitoring network: data from the existing ozone monitors located in urban Alachua and Duval counties to the west and north of the project; data from an existing PM_{10} monitor in Putnam County near the project site; and data from an existing NO_2 monitor in the Jacksonville area. As shown in the following table, the ambient monitoring data shows no violations of any AAQS.

EXISTING PRECONSTRUCTION AND BACKGROUND CONCENTRATIONS			
Pollutant	**Averaging Time**	**Background (μg/m³)**	**AAQS (μg/m³)**
PM_{10}	Annual	26	50
	24-hour	62	150
NO_2	Annual	27	100

Since an AAQS analysis is required for NO_2 and PM_{10}, the above ambient background concentrations for these pollutants will be used in the analysis.

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

Good Engineering Practice Stack Height

Good Engineering Practice (GEP) stack height means the greater of 65 meters (213 feet), or the maximum nearby building height plus 1.5 times the building height or width (whichever is less). The stacks for this project will be less than the corresponding GEP stack heights. Therefore, the potential for building downwash was considered in the modeling analysis for this project.

PSD Class II Area Model

AERMOD, the air dispersion model approved by the American Meteorological Society and the EPA, was used to evaluate the air quality impacts 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-hour, 8-hour, 3-hour and 1-hour averaging periods. 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 and building downwash effects were evaluated for stacks below the corresponding GEP stack height.

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. The 5-year period of meteorological data was from 2001 through 2005. 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 increment. 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 significant impacts occur in 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

The PSD Class I areas within 200 km of the project are the Okefenokee National Wilderness Area (NWA), the Chassahowitzka NWA and the Wolf Island NWA. Since these Class I areas 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 impacts on the PSD Class I increments and on the Air Quality Related Values (AQRV) for regional haze, nitrogen deposition 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 3-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. For 2001 through 2003 and a 4-km Florida domain, meteorological data were obtained and processed for use in the Class I analyses. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the federal land managers.

Receptor Grids Used in PSD Increment Analysis and AAQS Analysis

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. The sizes of the significant impact areas for the required PM_{10} and NO_2 analyses were 1 kilometer or less. Over 2000 receptors were placed along the restricted property line of the facility and out to 4 km from the facility.

Significant Impact Analysis

Preliminary modeling is conducted using only the proposed project's worst-case emission scenario for each pollutant and applicable averaging time. The Okefenokee NWA is the closest PSD Class I area and is located 108 km from the project at its closest point. The other PSD Class I areas located within 200 km of the facility are the Chassahowitzka NWA located 137 km southwest of the project and the Wolf Island NWA located 186 km to the north of the project. A total of 180, 113 and 30 receptors were placed in the Okefenokee NWA, Chassahowitzka NWA and Wolf Island NWA PSD Class I areas, respectively.

For each significant PSD pollutant that requires a PSD increment and/or AAQS analysis, a preliminary significant impact modeling analysis is conducted. The results of this analysis compares the maximum predicted impacts from the project with the corresponding regulatory significant impact levels to determine whether the project could have a significant impact in any PSD Class II area in the vicinity of the project or in any nearby PSD Class I area. If the maximum predicted impact is less than the regulatory significant impact level, the project is considered to have no significant impact on the AAQS or PSD increments, and the requirement to conduct a PSD air quality analysis is satisfied. However, if the maximum predicted impact is greater than the regulatory significant impact level, a full impact modeling analysis must be conducted. The full impact modeling analysis considers not only impacts from the project, but also impacts from other nearby major sources as well as background concentrations representing all other point and area source contributions. The following tables show the predicted maximum impacts due to the project for the Class I and II areas as well as the radius of impact for any significant Class II impact.

MAXIMUM PREDICTED PROJECT IMPACTS COMPARED TO THE SIGNIFICANT IMPACT LEVELS FOR THE PSD CLASS II AREAS 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	1.4	1	Yes	1
	24-hr	12	5	Yes	1
CO	8-hr	67	500	No	NA
	1-hr	79	2,000	No	NA
NO_2	Annual	2	1	Yes	1
VOC	Annual Rate	407 tons/year	100 tons/year	Yes	NA

MAXIMUM PREDICTED PROJECT IMPACTS COMPARED TO THE SIGNIFICANT IMPACT LEVELS FOR THE PSD CLASS I AREAS				
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	0.001	0.2	No
	24-hr	0.01	0.3	No
NO_2	Annual	0.003	0.1	No

As shown in the tables, the maximum predicted CO impacts due to the project are less than the regulatory significant impact levels for the Class II areas in the vicinity of the project. Also, the maximum predicted impacts of PM_{10} and NO_2 due to the project are less than the regulatory significant impact levels for the Class I areas. Therefore, no further air dispersion modeling was required for these pollutants in these areas. However, the maximum predicted impacts of PM_{10} and NO_2 due to 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 conduct a full modeling analysis to determine PM_{10} and NO_2 impacts within the applicable significant impact area for comparison to the AAQS and the PSD increments. The significant impact area is determined by the predicted radius of significant impact. These analyses are provided in the following sections.

The table also shows that potential VOC emissions increases are above the annual emission rate threshold of 100 tons per year established for the pollutant ozone. Since no stationary point source models are available and approved for use in predicting ozone impacts, the applicant presented potential VOC emissions increases to the Department and discussed available options to predict potential impacts associated with the VOC emissions and formation of ozone. 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. No further analysis is required for this pollutant.

PSD Increment Analysis

The PSD increment represents the amount that new sources in an area may increase the ambient concentrations of a pollutant from the baseline concentration. For PM_{10} and SO_2, the PSD increments were established in 1977 based on major sources of PM_{10} and SO_2 emissions for the baseline year of 1975. For NO_2, the PSD increment was established in 1988 based on major sources of NO_2 emissions for the baseline year of 1988. The emission rates input into the model for predicting increment consumption are based on maximum emissions from increment-consuming sources at the facility as well as all other increment-consuming sources in the vicinity of the facility. The following table shows the maximum predicted PM_{10} and NO_2 increments for the PSD Class II areas consumed by this project and all other increment-consuming sources in the vicinity of the project. As shown, the maximum predicted impacts are less than the allowable increments.

PSD CLASS II INCREMENT ANALYSIS				
Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact Greater Than Allowable Increment?
PM_{10}	Annual	0	17	No
	24-hour	22	30	No
NO_2	Annual	3	25	No

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 predicted concentration. The purpose of the background concentration is to account for all other point and area sources that are not explicitly modeled. The results of the AAQS analysis are summarized in the table below. As shown, the proposed project is 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 ($\mu g/m^3$)**	**AAQS ($\mu g/m^3$)**	**Greater Than AAQS?**
PM_{10}	Annual	11	26	37	50	No
	24-hour	42	62	104	150	No
NO_2	Annual	10	27	37	100	No

Ozone Discussion

This project results in PSD-significant increases of NO_X and VOC emissions, which are ozone precursors. A demonstration that these emissions increases will not cause or contribute to any predicted violations of the ozone standards would require the use of a very sophisticated and expensive air dispersion model and computer system. Such an analysis would need to be run for the entire region with key inputs to the model from traffic, power plants, other industrial sources, and complex meteorology. Potential emissions increases from this project are 405 tons per year of NO_X and 418 tons per year of VOC. At these rates, the contribution of these emissions is not considered significant in terms of impacts to the overall regional ozone concentrations. The uncertainty of the impacts predicted by a regional ozone model would likely be greater than the impacts contributed by this project.

Additional Impacts Analysis

Impacts on Soils, Vegetation, Wildlife and Visibility

The maximum predicted ambient concentrations of CO, NO_X and PM_{10} due to the proposed project, including all other nearby sources, are less than corresponding AAQS, which 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 any PSD Class II area in the vicinity of the project. The applicant conducted an analysis for air quality related values (AQRV) for the nearby PSD Class I area. No significant impacts on this area are expected. The applicant conducted a regional haze analysis using the long-range transport model CALPUFF for the nearby PSD Class I areas. No significant visibility impacts are predicted in the PSD Class I areas. The CALPUFF model was also used to predict total nitrogen deposition rates on the PSD Class I areas. The maximum predicted deposition rates were less than the threshold levels recommended by the federal land manager.

Growth-Related Air Quality Impacts

The proposed modification will not substantially change employment, population, housing, commercial development, or industrial development in the area. Therefore, no significant air quality impacts are predicted.

Conclusion

The applicant provided reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any AAQS or PSD increments as described in the application, summarized in this report, and subject to the specific conditions of the draft permit.

8. 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 documents. Cleve Holladay is the staff meteorologist responsible for reviewing the ambient air quality analyses. Jeff Koerner, P.E. is the Air Permitting Supervisor responsible for reviewing and editing 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.

DRAFT PERMIT

PERMITTEE

Georgia-Pacific Consumer Operations LLC
Post Office Box 919
Palatka, Florida 32178-0919

Authorized Representative:
Mr. Keith Wahoske, Vice President

Air Permit No. 1070005-038-AC
PSD No. PSD-FL-380
Georgia-Pacific Palatka Mill
PSD Modification
SIC Nos. 2611 and 2621
Permit Expires: November 1, 2009

FACILITY AND LOCATION

Georgia-Pacific Consumer Operations LLC operates the Palatka Mill, which is a Kraft process pulp and paper mill located North of County Road 216 and West of U.S. Highway 17 in Palatka, Putnam County, Florida. The map coordinates are: UTM Zone 17; 434.0 km East; and, 3283.4 km North. This permit requires permanent shutdown of the No. 4 Power Boiler and authorizes modifications to the No. 5 Power Boiler, No. 4 Lime Kiln, No. 4 Recovery Boiler, and No. 4 multiple effect evaporator set.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Parts 60 and 63 of the Code of Federal Regulations (CFR). The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

CONTENTS

(DRAFT)

Joseph Kahn, Director
Division of Air Resource Management

Effective Date

FACILITY DESCRIPTION

Georgia-Pacific operates an existing paper and pulp mill in Palatka, Florida using the Kraft sulfate process. In the Kraft process, the digesting liquor (white liquor) is a solution of sodium hydroxide and sodium sulfide that is mixed with wood chips and cooked under pressure. The spent liquor, known as weak black liquor, is concentrated and sodium sulfate is added to make up for chemical losses. The black liquor solids (BLS) are burned in the recovery furnace to produce a smelt of sodium carbonate and sodium sulfide. The smelt is dissolved in water to form green liquor to which quicklime (calcium oxide) is added to convert the sodium carbonate back to sodium hydroxide, which reconstitutes the cooking liquor. The spent lime cake (calcium carbonate) is recalcined in a rotary lime kiln to produce quicklime, which is used to convert the green liquor to cooking liquor. Other steam and energy needs are met by the power boilers, which burn a variety of fuels including fuel oil and natural gas.

REGULATORY CLASSIFICATION

- The facility is a major source of hazardous air pollutants (HAP).
- The facility operates no units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution.
- The facility is a major stationary source subject to the Prevention of Significant Deterioration (PSD) of Air Quality.

PROJECT DESCRIPTION

This permit authorizes the following major modifications: permanent shutdown of the No. 4 Power Boiler; conversion of the No. 5 Power Boiler to natural gas; replacement of the hot-end section and cooler tubes for the No. 4 Lime Kiln; extensive tube replacement and modification of the combustion air system (including the addition of a fourth level of overfire air) for the No. 4 Recovery Boiler; and the addition of a crystallizer with associated storage/flash tank and modifications to the two concentrators associated with the No. 4 multiple effect evaporator set. This permit affects the following emissions units.

ID	Emission Unit Description
014	No. 4 Power Boiler
015	No. 5 Power Boiler
016	No. 4 Combination Boiler
017	No. 4 Lime Kiln
018	No. 4 Recovery Boiler
xxx	Noncondensable Gas System including the No. 4 Multiple Effect Evaporator (MEE) Set

The permittee conducted a PSD netting analysis based on contemporaneous emissions increases and decreases to avoid PSD preconstruction review for sulfur dioxide (SO_2), sulfuric acid mist (SAM), and total reduced sulfur (TRS). The project is subject to PSD preconstruction review for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM), and volatile organic compounds (VOC). For this permit, the Department determined the Best Available Control Technology (BACT) for the following units: the No. 5 Power Boiler (CO and VOC); the No. 4 Lime Kiln (CO, NO_X, PM, and VOC); and the No. 4 Recovery Boiler (CO, NO_X, PM, and VOC). The No. 4 Combination Boiler is currently under PSD preconstruction review in Project No. 1070005-045-AC for CO, NO_X, PM, and VOC. Throughout this permit, particulate matter emissions are referred to as PM emissions, which serve as a surrogate for regulating $PM_{2.5}$ and PM_{10} emissions.

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action: the permit application and additional information received to make it complete; the draft permit package including the Department's Technical Evaluation and Preliminary Determination; publication and comments; the Department's Final Determination; previous air construction permits; and the current Title V air operation permit.

1. Permitting Authority: The Permitting Authority for this project is the Bureau of Air Regulation in the Division of Air Resource Management of the Department. The mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The phone number is 850/488-0114.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's Northeast District Office. The mailing address is 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida, 32256. The phone number is 904/807-3300.

3. Appendices: The following Appendices are attached as part of this permit:
   a. Appendix A. Citation Formats
   b. Appendix B. General Conditions
   c. Appendix C. Common Conditions
   d. Appendix D. Standard Testing Requirements
   e. Appendix E. Standard Continuous Monitoring Requirements
   f. Appendix F. Final BACT Determinations and Emissions Summary
   g. Appendix G. On-Specification Used Oil Requirements

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.

5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

6. Modifications: No emissions unit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Source Obligation:
   (a) Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit.
   (b) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

(c) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

[Rule 62-212.400(12), F.A.C.]

8. <u>Title V Permit</u>: This permit authorizes specific modifications and/or new construction on the affected emissions units as well as initial operation to determine compliance with conditions of this permit. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after completing the required work and commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Air Resource Section of the Department's Northeast District Office. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

9. <u>Previous Air Construction Permits</u>: This permit supplements all previous permits issued for the affected emissions units. The conditions of this permit satisfy the applicable requirements for the emissions increases related to the project. These conditions supersede corresponding similar conditions specified in previous air construction permits. However, if not specifically regulated by this permit, other standards and permit requirements from previous air construction permits remain valid. The affected emissions units remain subject to all applicable standards and regulations as regulated by the Title V air operation permit. [Rules 62-212.300 and 62-212.400 (BACT), F.A.C.]

A. No. 4 Power Boiler and No. 4 Combination Boiler

This subsection of the permit addresses the following emissions units.

ID	Emission Unit Description
014	No. 4 Power Boiler
016	No. 4 Combination Boiler

{Permitting Note: In accordance with Rule 62-212.400 (PSD), F.A.C., the permittee conducted a PSD netting analysis that used contemporaneous emissions decreases from the permanent shutdown of the No. 4 Power Boiler to avoid PSD preconstruction review for SO_2, SAM, and TRS.}

PERFORMANCE RESTRICTIONS

1. Shutdown: The No. 4 Power Boiler is currently not in operation. As part of this project, the permittee shall permanently shutdown the No. 4 Power Boiler. Within 90 days of issuance of this permit, the permittee shall provide written notice of the permanent shutdown of this unit. [Rules 62-4.070(3) and 62-212.400(12), F.A.C.]
2. PSD Review: The permittee plans to modify the No. 4 Combination Boiler. Although a review is being conducted under Project No. 1070005-045-AC, emissions increases from this unit were included in the PSD netting analysis. That project is also subject to PSD preconstruction review for CO, NO_X, PM, and VOC emissions. [Rule 62-212.400 (PSD), F.A.C.]
3. Oil Firing – No. 4 Combination Boiler: The maximum sulfur content of oil is 2.35% by weight. No more than 5,100,000 gallons of oil shall be fired during any consecutive 12 months. The permittee shall keep records on a monthly basis to ensure compliance with the oil firing restriction. *{Permitting Note: This limits oil firing to an annual capacity factor of approximately 21% of the total maximum heat input rate to the unit.}*

This subsection of the permit addresses the following emissions unit.

ID	Emission Unit Description
015	**No. 5 Power Boiler**: This unit fires natural gas to produce steam and power for use at the mill. The permitted capacity is 568.9 MMBtu per hour of heat input to produce approximately 445,200 lb/hour of steam. CO, NO_X and VOC emissions are controlled by the burner design and efficient combustion of natural gas, which also minimizes PM/PM_{10}, SAM and SO_2 emissions. At permitted capacity, the exhaust gas flow rate is 135,400 dscfm at 10% oxygen with an exit temperature of 500° F. Exhaust gases exit a stack that is 9.0 feet in diameter and 156.5 feet tall.

{Permitting Note: In accordance with Rule 62-212.400 (PSD), F.A.C., the above emission unit is subject to BACT determinations for CO and VOC emissions, which are presented in Appendix E of this permit.}

EXISTING APPLICABLE REQUIREMENTS

1. State Rule for Kraft Pulp Mills: The No. 5 Power Boiler is subject to the applicable requirements of Rule 62-296.404, F.A.C. for Kraft Pulp Mills.
2. State Rule for Large Boilers: The No. 5 Power Boiler is subject to the applicable requirements of Rule 62-296.405, F.A.C. for Fossil Fuel Steam Generators with More than 250 MMBtu per hour of Heat Input.
3. NESHAP Subpart S for Kraft Pulp Mills: The No. 5 Power Boiler is subject to the applicable MACT requirements in NESHAP Subpart S in 40 CFR 63.
4. NESHAP Subpart DDDDD for Industrial Boilers: The No. 5 Power Boiler is subject to the applicable requirements for existing units specified in NESHAP Subpart DDDDD of 40 CFR 63 for Industrial, Commercial, and Institutional Boilers and Process Heaters.
5. PCP Exemption: This current permitting action does not affect the previous authorization of Permit No. 1070005-024-AC issued on July 2, 2004 for destroying DNCGs issued as a Pollution Control Project (PCP) pursuant to Rule 62-212.400(2)(a)2.b, F.A.C. That permit specified the strategy for complying with the applicable requirements of the MACT standards in NESHAP Subpart S in 40 CFR 63. That permit authorizes the No. 5 Power Boiler to destroy dilute non-condensable gases (DNCGs) from the high-volume, low-concentration (HVLC) system, which include emissions from brown stock washers, pressure knotters, the bleach plant pre-washer, the oxygen delignification system, and softwood/hardwood high density storage tanks. The DNCGs are introduced with the primary fuel, directed into the flame zone, or added with the combustion air. Optionally, the DNCGs may also be directed to the No. 4 Combination Boiler, which shares common permit conditions with the No. 5 Power Boiler. Permit No. 1070005-024-AC limits SO_2 emissions to 82.6 lb/hour and 236.3 tons per year from the destruction of DNCGs in any combination of the No. 4 Combination Boiler and the No. 5 Power Boiler. [Permit No. 1070005-024-AC; Rule 62-212.400 (PSD), F.A.C.]

MODIFICATIONS AND CAPACITIES

6. Natural Gas Conversion: The permittee shall convert the No. 5 Power Boiler to a natural gas-fired boiler. The permittee shall remove the oil burners and install natural gas burners that will achieve the emissions standards and capacities specified in this permit. If necessary to achieve the NO_X standard, the permittee is authorized to install a flue gas recirculation system consisting of the necessary fans, ductwork, and dampers. The conversion to natural gas shall be completed by April 1, 2008. Once converted to natural gas, the existing electrostatic precipitator may be removed from the No. 5 Power Boiler. It may be used as additional fields for controlling PM emissions from the No. 4 Combination Boiler. [Application No. 1070005-038-AC; Rule 62-212.400 (PSD), F.A.C.]

7. Authorized Fuels: The No. 5 Power Boiler shall be converted to fire pipeline natural gas as the sole fuel. After completing the project, the firing of oil is prohibited. As a control device, the No. 5 Power Boiler is authorized to destroy dilute non-condensable gases (DNCGs) from the high-volume, low-concentration (HVLC) system *{Permitting Note: The No. 5 Power Boiler currently fires oil with a maximum sulfur content of 2.35% by weight. After conversion to natural gas, potential annual SO_2 emissions will be less than 2 tons per year and potential SAM and TRS emissions will be negligible.}* [Application No. 1070005-038-AC; Rule 62-212.400 (PSD), F.A.C.]

8. Permitted Capacity: After converting to natural gas, the permitted capacity of the No. 5 Power Boiler shall be 568.9 MMBtu of heat input per hour based on a 24-hour average. At this heat input rate, the unit will produce approximately 445,200 lb/hour of steam based on a 24-hour average. Hours of operation are not restricted (8760 hours/year). [Application No. 1070005-038-AC; Rules 62-210.200 (PTE) and 62-212.400 (PSD), F.A.C.]

EMISSIONS AND PERFORMANCE STANDARDS

9. CO Standard: As determined by EPA Method 10, CO emissions shall not exceed 0.185 lb per MMBtu of heat input and 105.2 lb/hour based on the average of three test runs. The CO standard serves as a surrogate standard for minimizing VOC emissions as a result of the efficient combustion of natural gas. *{Permitting Note: VOC emissions are expected to be less than 14 tons per year from firing natural gas.}* [Rule 62-212.400 (BACT), F.A.C.]

10. NO_X Standard: As determined by EPA Method 7E, NO_X emissions shall not exceed 0.125 lb/MMBtu of heat input and 71.1 lb/hour based on the average of three test runs. [Rules 62-4.070(3) and 62-212.400(12), F.A.C.]

COMPLIANCE MONITORING AND TESTING

11. Standard Testing Requirements: All required emissions tests shall be conducted in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. [Rules 62-204.800 and 62-297.100, F.A.C.; and 40 CFR 60, Appendix A]

12. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. [Rule 62-297.310(7)(a)9, F.A.C.]

13. Test Methods: When required, tests shall be performed in accordance with the following methods.

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Note: The method shall be based on a continuous sampling train.}
19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)

Tests shall also be conducted in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

14. Initial Stack Tests: In accordance with the specified test methods, the No. 5 Power Boiler shall be tested to demonstrate compliance with the emissions standards for CO and NO_X. Initial stack tests for these pollutants shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial startup on natural gas. All initial tests shall be conducted with the emissions unit operating at 90% to 100% of the permitted capacity; otherwise, this permit shall be modified to reflect the true maximum capacity as constructed. The Department may require the permittee to repeat some or all of the initial stack tests after major replacement or major repair of emissions-related equipment. [Rules 62-4.070(3), 62-212.400(PSD) and 62-297.310(7), F.A.C.]

15. Annual Stack Tests: During each federal fiscal year (October 1st to September 30th), the No. 5 Power Boiler shall be tested to demonstrate compliance with the emission standards for CO and NO_X. Testing of emissions shall be conducted with the emissions unit operating at 90% to 100% of the permitted capacity. If it is impractical to test within this range, the emissions unit may be tested at less than 90% of the maximum permitted capacity. In this case, subsequent emissions unit operation is limited to 110% of the tested 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. *{Permitting Note: Additional tests may be required by other applicable requirements.}* [Rules 62-4.070(3), 62-212.400(PSD) and 62-297.310(7), F.A.C.]

16. Fuel Monitoring: The permittee shall install equipment to continuously monitor the flow rates of natural gas and DNCGs to the No. 5 Power Boiler. This may consist of fuel flow meters with integrators to monitor each flow rate. [Rules 62-4.070(3) and 62-212.400(12), F.A.C.]

RECORDS AND REPORTS

17. Test Reports: For each required test, the permittee shall file a report with the Compliance Authority on the results of each required test in accordance with the requirements of Rule 62-297.310(8), F.A.C.

18. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the No. 5 Power Boiler on a daily average basis considering the number of hours of operation during each day. This shall be achieved through monitoring daily rates of consumption and heat content of natural gas. The information shall be documented and recorded for each day of operation. Records shall be made available to the Compliance Authority upon request. [Rule 62-4.070(3), F.A.C.]

This subsection of the permit addresses the following emissions unit.

ID	Emission Unit Description
017	**No. 4 Lime Kiln**: This unit recalcines the spent lime cake (calcium carbonate) to produce the quicklime (calcium oxide), which is used to convert the green liquor to cooking liquor. The kiln fires residual fuel oil and has a maximum processing rate of 41.5 tons of material per hour based on a 24-hour average. Particulate matter emissions are controlled by a cyclonic dust collector followed by a wet venturi scrubber. TRS emissions, scrubber pressure drop, and scrubber flow rate are continuously monitored and recorded. At permitted capacity, the exhaust gas flow rate is 54,200 dscfm at 10% oxygen with an exit temperature of 164° F. Exhaust gases exit a stack that is 4.4 feet in diameter and 131 feet tall.

{Permitting Note: In accordance with Rule 62-212.400 (PSD), F.A.C., the above emission unit is subject to BACT determinations for CO and VOC emissions, which are presented in Appendix E of this permit.}

EXISTING APPLICABLE REQUIREMENTS

1. State Rule for Kraft Pulp Mills: The No. 4 Lime Kiln remains subject to the applicable requirements of Rule 62-296.404, F.A.C. for Kraft Pulp Mills.
2. NESHAP Subpart MM for Kraft Pulp Mills: The No. 4 Lime Kiln remains subject to the applicable MACT requirements in NESHAP Subpart S in 40 CFR 63.
3. PSD Permit: Unless otherwise specified by condition in this permit, the No. 4 Lime Kiln remains subject to the applicable requirements of Permit No. PSD-FL-171.

MODIFICATIONS AND CAPACITIES

4. Kiln Modification: For the No. 4 Lime Kiln, the permittee is authorized to replace approximately 62 feet of the hot-end kiln shell and all 10 coolers located in this section. The new coolers will be mounted with an improved bracket design to prevent stress cracks underneath the coolers. [Rule 62-210.300(1), F.A.C.]
5. Permitted Capacity: The maximum processing rate of the No. 4 Lime Kiln is 41.5 tons of material per hour based on a 24-hour average. This corresponds to a maximum production rate of 19.4 tons per hour of quicklime. There is no restriction on the hours of operation (8760 hours/year). At permitted capacity, the maximum flue gas flow rate is 54,200 dscfm @ 10% oxygen. The lime kiln typically operates at flue gas oxygen contents in the range of 4% to 6% by volume. [Application No. 1070005-038-AC; Rule 62-210.200 (PTE), F.A.C.]
6. Authorized Fuels: The No. 4 Lime Kiln is authorized to fire residual fuel oil with a maximum fuel sulfur content of 2.35% by weight as the primary fuel. On-specification used oil meeting the requirements in Appendix G of this permit may be blended with the residual oil and fired at a rate of no more than 10% of the fuel consumed. Natural gas is authorized as a startup and alternate fuel. The maximum heat input rate is 140 MMBtu per hour when firing a maximum of 933 gallons per hour of residual oil with a heating value of 150,000 Btu per gallon. No more than 8,173,000 gallons of oil shall be fired during any consecutive 12 months. [Application No. 1070005-038-AC; Rule 62-210.200 (PTE), F.A.C.]

EMISSIONS AND PERFORMANCE STANDARDS

7. CO Standard: As determined by EPA Method 10, CO emissions shall not exceed 69.0 ppmvd at 10% O_2 and 16.3 lb/hour based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

8. NOx Standard: As determined by EPA Method 7E, NO_X emissions shall not exceed 140.0 ppmvd at 10% O_2 and 54.2 lb/hour based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

9. PM Standard: As determined by EPA Method 5, PM emissions from the No. 4 Lime Kiln shall not exceed 0.55 lb per ton of actual material processed and 22.9 lb/hour based on the average of three test runs. *{Permitting Note: The venturi scrubber causes a wet plume, which interferes with the determination of opacity. The scrubber monitoring provisions will be used to ensure proper operation of the venturi scrubber.}* [Rule 62-212.400 (BACT), F.A.C.]

10. SO_2 Standard: As determined by EPA Method 8, SO_2 emissions shall not exceed 16.9 ppmvd at 10% O_2 and 9.1 lb/hour based on the average of three test runs. [Rule 62-212.400(12), F.A.C.]

11. TRS Standard: As determined by the existing CEMS, TRS emissions shall not exceed 25.1 tons per year based on a 12-month rolling CEMS total. [Rule 62-212.400(12), F.A.C.]

12. VOC Standard: As determined by EPA Method 25A, VOC emissions from the lime kiln shall not exceed 70.0 ppmvd at 10% O_2 and 9.4 lb/hour (total hydrocarbons determined as methane) based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

COMPLIANCE MONITORING AND TESTING

13. Standard Testing Requirements: All required emissions tests shall be conducted in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. [Rules 62-204.800 and 62-297.100, F.A.C.; and 40 CFR 60, Appendix A]

14. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. [Rule 62-297.310(7)(a)9, F.A.C.]

15. Test Methods: When required, tests shall be performed in accordance with the following methods.

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5	Determination of Particulate Matter from Stationary Sources
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Note: The method shall be based on a continuous sampling train.}
19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)

Tests shall also be conducted in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

16. Initial Compliance Tests: The No. 4 Lime Kiln shall be tested to demonstrate initial compliance with the emissions standards specified for CO, NO_X, PM, SO_2, and VOC. The initial tests shall be conducted within 60 days after completing the kiln modification and achieving permitted capacity, but not later than 180 days after initial operation of the unit. [Rules 62-297.310(7)(a)1 and 62-212.400 (BACT), F.A.C.]

17. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the No. 4 Lime Kiln shall be tested to demonstrate compliance with the emissions standards for CO, NO_X, PM, SO_2, and VOC. If consecutive annual tests for CO or VOC emissions show compliance at 50% of the standard or less, the test frequency for that pollutant is reduced to testing prior to renewal of the operation permit. Annual testing shall resume for any subsequent failure to demonstrate compliance at renewal. [Rules 62-297.310(7)(a)4 and 62-212.400 (BACT), F.A.C.]

18. Tests Prior to Renewal: Within the 12-month period prior to expiration of the operation permit, the No. 4 Lime Kiln shall be tested to demonstrate compliance with the emission standards for CO, NO_X, PM, SO_2, and VOC. [Rules 62-297.310(7)(a)3 and 62-212.400 (BACT), F.A.C.]

19. Scrubber Monitoring: The permittee shall install, operate, and maintain equipment to continuously monitor and record the venturi scrubber pressure drop and flow rate. In accordance with the monitoring requirements specified in NESHAP Subpart MM, minimum operating levels shall be determined for these parameters; however, the operating levels shall be selected to ensure compliance with the BACT standard specified in this permit. If monitors show operation below the minimum operating levels, the permittee shall take appropriate corrective actions to regain proper operation of the control system. [Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

20. Fuel Monitoring: The permittee shall install equipment to continuously monitor the flow rates of natural gas and DNCGs to the No. 5 Power Boiler. This may consist of fuel flow meters with integrators to monitor each flow rate. [Rules 62-4.070(3) and 62-212.400(12), F.A.C.]

RECORDS AND REPORTS

21. Scrubber Records: The permittee shall continuously monitor and record the venturi scrubber pressure drop and flow rate in accordance with the monitoring requirements specified in NESHAP Subpart MM. The permittee shall document and record corrective actions taken to regain proper operation of the control system if operation falls below the minimum operating levels. [Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

22. Kiln Process Rate: The permittee shall monitor and record the total lime mud input to the No. 4 Lime Kiln on an hourly basis and record the daily average in tons per hour. [Rule 62-4.070(3), F.A.C.]

23. Fuel Records: On a monthly basis, the permittee shall document the amount of oil fired during each calendar month and the 12-month rolling total. [Rule 62-4.070(3), F.A.C.]

24. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. For each test run, the report shall also indicate the lime kiln processing rate, the fuel firing rate, the venturi scrubber pressure differential, and the venturi scrubber flow rate. [Rule 62-297.310(8), F.A.C.]

This subsection of the permit addresses the following emissions unit.

ID	Emission Unit Description
018	**No. 4 Recovery Boiler**: This unit fires black liquor solids (BLS) as the primary fuel to facilitate the recovery of the cooking liquor. Residual fuel oil is fired as a startup and supplemental fuel. The maximum steam production rate is 789,000 lb/hour (24-hour average) for steam conditions of 850° F to 900° F at 1250 psi. Particulate matter emissions are controlled by an electrostatic precipitator (ESP) with automatic voltage control, 2-chambers, and 6 electric fields per chamber. Total reduced sulfur emissions are reduced by the low-odor design. NO_X emissions are controlled by a four-level overfire air system. CO and VOC emissions are controlled by good combustion design and operating practices. CO, NO_X, SO_2, TRS, and opacity are continuously monitored and recorded. At permitted capacity, the exhaust gas flow rate is 294,000 dscfm at 8% oxygen with an exit temperature of 400° F. Exhaust gases exit a stack that is 12 feet in diameter and 230 feet tall.

{Permitting Note: In accordance with Rule 62-212.400 (PSD), F.A.C., the above emission unit is subject to BACT determinations for CO, NO_X, PM, and VOC emissions, which are presented in Appendix E of this permit.}

EXISTING APPLICABLE REGULATIONS

1. State Rule for Kraft Pulp Mills: The No. 4 Recovery Boiler is subject to the applicable requirements for existing units in Rule 62-296.404, F.A.C. These standards are specified in the Title V air operation permit.
2. NSPS Subpart BB: The No. 4 Recovery Boiler is subject to the applicable requirements specified in NESHAP Subpart BB of 40 CFR 63 for recovery combustion sources at Kraft pulp mills. These standards are specified in the Title V air operation permit.
3. NESHAP Subpart MM: The No. 4 Recovery Boiler is subject to the applicable requirements specified in NESHAP Subpart MM of 40 CFR 63 for recovery combustion sources at Kraft pulp mills. These standards are specified in the Title V air operation permit.
4. PSD Permits: Unless otherwise specified by condition in this permit, the No. 4 Recovery Boiler remains subject to the applicable requirements of Permit Nos. PSD-FL-171 and PSD-FL-226.

MODIFICATIONS AND CAPACITIES

5. No. 4 Recovery Boiler Modifications: The permittee is authorized to perform the following modifications to the No. 4 Recovery Boiler in accordance with the following preliminary schedule: modify the combustion air system; add a fourth level of overfire air (quaternary air); and replace tubes in the superheater, economizer, and walls of the recovery boiler. These changes will not increase the existing permitted capacity of the recovery boiler or the pulp mill. The preliminary schedule is to begin construction in May of 2007. [Application No. 1010005-038-AC; Rules 62-212.300 and 62-212.400 (PSD), F.A.C.]
6. Capacities, Fuels and Restrictions: The No. 4 Recovery Boiler fires BLS as the primary fuel for the recovery process as well as the following fuels: natural gas as a startup and supplemental fuel; residual fuel oil with a maximum sulfur content of 2.35% by weight; and limited amounts of on-specification used oil meeting the requirements in Appendix G of this permit. The permitted capacity is 210,000 lb/hour of BLS based on a 24-hour average. The maximum consumption of oil (residual oil and on-specification used oil) shall not exceed 7,860,640 gallons during any consecutive 12-months. On-specification used oil shall be blended with residual oil and shall not exceed 10% of the oil consumed. Hours of operation are not restricted (8760 hours/year). *{Permitting Note: The maximum heat input from firing BLS is 1345*

MMBtu/hour based on the permitted capacity and a heating value of 6410 Btu/lb of BLS. The oil firing restriction maintains an annual capacity factor of less than 10% for fossil fuel firing.} [Application No. 1070005-038-AC; Rules 62-210.200 (PTE) and 62-212.400 (PSD), F.A.C.]

7. Fuel Monitoring: The permittee shall install equipment to continuously monitor the flow rates of all fuels for the No. 4 Recovery Boiler. This may consist of fuel flow meters with integrators to monitor each flow rate. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

8. CEMS: To demonstrate compliance with the emissions standards for the No. 4 Recovery Boiler, the permittee shall properly install, calibrate, operate and maintain continuous emissions monitoring systems (CEMS) to measure and record CO and NO_X emissions in the terms of the applicable standard. The systems shall include continuous monitors to determine the flue gas oxygen content and exhaust flow rate. Each CEMS shall be installed such that representative measurements of emissions or process parameters from the facility are obtained. The permittee shall locate the CEMS by following the procedures contained in the applicable performance specification of 40 CFR Part 60, Appendix B. Within 240 calendar days of completing construction of the fourth level of overfire air, the permittee shall install and certify the required CEMS in accordance with the applicable performance specifications identified in Appendix F (Standard Continuous Monitoring Requirements) of this permit. *{Permitting Note: This unit has existing continuous monitors for determining opacity, SO_2 and TRS emissions.}* [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

EMISSIONS AND PERFORMANCE STANDARDS

9. CO Standards:

   a. After completing installation of the four-level overfire air system, CO emissions shall not exceed 800.0 ppmvd @ 8% O_2 and 1025.4 lb/hour as determined by EPA Method 10 stack testing. *{Permitting Note: Once compliance with this standard is demonstrated and the CO CEMS is certified, this standard becomes obsolete.}*

   b. Once the CO CEMS is certified, compliance shall be determined by data collected from the required CEMS. For the initial 180 calendar days after certifying the CEMS, CO emissions shall not exceed 800.0 ppmvd @ 8% O_2 and 1025.4 lb/hour based on a 30-day rolling CEMS average, excluding periods of startup and shutdown. Thereafter, CO emissions shall not exceed 400.0 ppmvd @ 8% O_2 and 512.7 lb/hour based on a 30-day rolling CEMS average, excluding periods of startup and shutdown. [Rule 62-212.400 (BACT), F.A.C.]

10. NOx Standards:

    a. After completing installation of the four-level overfire air system, NO_X emissions shall not exceed 80.0 ppmvd @ 8% O_2 and 168.5 lb/hour as determined by EPA Method 10 stack testing. *{Permitting Note: Once compliance with this standard is demonstrated and the NO_X CEMS is certified, this standard becomes obsolete.}*

    b. As determined by data collected from the required CEMS, NO_X emissions shall not exceed 80.0 ppmvd @ 8% O_2 and 168.5 lb/hour based on a 30-day rolling CEMS average, excluding periods of startup and shutdown. [Rule 62-212.400 (BACT), F.A.C.]

11. Opacity Standard: Once the ESP in placed in service during startup of the recovery boiler, visible emissions shall not exceed 20% opacity based on a 6-minute average as determined by the existing COMS and EPA Method 9. [Rule 62-212.400 (BACT), F.A.C.]

12. PM Standard: As determined by EPA Method 5 or 29, PM emissions shall not exceed 0.030 grains per dscf @ 8% O_2 and 75.6 lb/hour based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

13. SO₂ Standard: As determined by data collected from the existing CEMS, SO_2 emissions shall not exceed 153.9 tons per year based on a 12-month rolling CEMS total. [Rule 62-212.400(12), F.A.C.]

14. TRS Standard: As determined by data collected from the existing CEMS, TRS emissions shall not exceed 34.2 tons per year based on a 12-month rolling CEMS total. [Rule 62-212.400(12), F.A.C.]

15. VOC Standard: As determined by EPA Method 25A, VOC emissions shall not exceed 0.20 lb/ton of BLS and 21.0 lb/hour (THC determined as methane) based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

16. ESP Operation: The permittee shall operate and maintain the ESP to minimize PM emissions. The permittee may conduct additional stack tests with fields removed from service to determine compliance with the PM and opacity standards for these periods. During such tests, the permittee shall continuously monitor and record the parameters necessary to determine the secondary power input to the ESP. If these tests demonstrate compliance, the permittee is authorized to operate the ESP under the operating conditions of the tests when conducting repairs or maintenance on the ESP. [Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

COMPLIANCE MONITORING AND TESTING

17. Compliance by CEMS: Compliance with the opacity, SO_2, and TRS standards shall be demonstrated with data collected from the existing COMS and CEMS. Compliance with the CO and NO_X standards shall be demonstrated with data collected from the CEMS required by this permit. The permittee shall comply with the conditions of Appendix F (Standard Continuous Monitoring Requirements) of this permit as the compliance method for the corresponding emissions standards. [Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

18. Standard Testing Requirements: All required emissions tests shall be conducted in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

19. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. [Rule 62-297.310(7)(a)9, F.A.C.]

20. Test Methods: When required, tests shall be performed in accordance with the following methods.

EPA Method	Description of Method and Comments
1 - 4	Methods for Determining Traverse Points, Velocity, Flow Rate, Gas Analysis, and Moisture Content These methods shall be performed as necessary to support other methods.
5	Method for Determining Particulate Matter Emissions
7E	Method for Determining NOx Emissions (Instrumental)
9	Method for Determining Opacity Observations
10	Method for Determining Carbon Monoxide Emissions (Instrumental) The method shall be based on a continuous sampling train.
19	Methods for Determining NO_X, PM, and SO_2 Mass Emission Rates
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)
29	Method for Determining Metals Emissions from Stationary Sources

The above methods are specified in Appendix A of 40 CFR 60 and are adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the

Department. [Rules 62-4.070(3), 62-204.800(8) and 62-212.400 (BACT), F.A.C.; 40 CFR 60, Appendix A]

21. Compliance Tests: In accordance with the following requirements, the permittee shall have stack tests conducted to demonstrate compliance with the emissions standards specified in this permit for CO, NO_X, PM and VOC.
    a. *Initial Tests*: Initial compliance tests shall be conducted within 60 calendar days of installing the fourth level of overfire air and achieving permitted capacity, but no later than 180 calendar days after initial startup. For the initial CO and NO_X tests prior to certification of the CEMS, the permittee shall demonstrate compliance with at least three hours of data, but no more than nine hours of data. [Rules 62-212.400 (BACT) and 62-297.310(7), F.A.C.]
    b. *Subsequent Tests*: During each federal fiscal year (October 1^{st} to September 30^{th}), compliance tests shall be conducted to determine PM emissions. Because VOC emissions are expected to be low and the CO CEMS will ensure efficient combustion, subsequent tests shall be conducted prior to renewal of the operation permit or when the Department requests a special test pursuant to Rule 62-297.310(7)(b), F.A.C.
    c. *Test Fuel*: Compliance tests shall be conducted when firing BLS at permitted capacity. [Rules 62-4.070(3), 62-212.400 (BACT) and 62-297.310, F.A.C.]
    d. *Operational Data for Tests*: For each test run, the permittee shall monitor and record the following information: fuel feed rate; the secondary power input to the ESP; the flue gas oxygen content (%); CO, NO_X, SO_2 and TRS CEMS data; and opacity COMS data. [Rules 62-297.310 and 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

22. Stack Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Compliance Authority on the results of each such test. The required test report shall be filed with the Compliance Authority as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Compliance Authority 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 information specified in Rule 62-297.310(8), F.A.C. The stack test shall also report all operational data collected during each test run. [Rule 62-297.310(8), F.A.C.]
23. Semiannual Monitoring Reports: The permittee shall submit a written report to the Compliance Authority summarizing the following for each calendar quarter: CO, NO_X, SO_2, and TRS emissions; opacity; CEMS monitor availability; gallons of oil fired; and total hours of operation. The reports shall identify any exceedance of an emissions or performance limitation. The reports are due within 30 days following the second and fourth calendar quarters. [Rule 62-4.070(3), F.A.C.]

E. No. 4 Multiple Effect Evaporator Set

This subsection of the permit addresses the following emissions unit.

ID	Emission Unit Description
xxx	Noncondensable Gas System including the No. 4 Multiple Effect Evaporator (MEE) Set

EXISTING APPLICABLE REGULATIONS

1. State Rule for Kraft Pulp Mills: This emissions unit is subject to the applicable requirements for existing units in Rule 62-296.404, F.A.C. These standards are specified in the Title V air operation permit.
2. NSPS Subpart BB: This emissions unit is subject to the applicable requirements specified in NESHAP Subpart BB of 40 CFR 63 for recovery combustion sources at Kraft pulp mills. These standards are specified in the Title V air operation permit.

MODIFICATIONS AND CAPACITIES

3. No. 4 MEE Set: The permittee is authorized to install a new crystallizer and associated storage/flash tank as a modification to the existing multiple effect evaporator (MEE) set with two associated concentrators (EU-032). The purpose is to increase the temperature and flash-off moisture from the black liquor, which will increase the solids content of the BLS from 65% to approximately 75%. The BLS fired in the existing No. 4 Recovery Boiler will contain less moisture. Emissions from the crystallizer and associated storage/flash tank shall be directed back to the MEE set and collected as part of the existing noncondensable gas (NCG) collection system. The preliminary schedule is to begin construction in May of 2007 and startup the new equipment by May of 2008. [Application No. 1010005-038-AC; Rules 62-212.300 and 62-212.400 (PSD), 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

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

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 these 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 and 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 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 not 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 permittee to cause pollution in contravention of F.S. 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 or 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 and records 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 noncompliance, 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 F.S. 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 F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. 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:
    a. Determination of Best Available Control Technology;
    b. Determination of Prevention of Significant Deterioration; and
    c. Compliance with New Source Performance Standards.
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 or 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:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) 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.

COMMON CONDITIONS

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 (VOC) or organic solvents (OS) 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(Definitions), 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% 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.]

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

RECORDS AND REPORTS

10. 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 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]
11. 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(3), F.A.C.]

STANDARD TESTING REQUIREMENTS

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

COMPLIANCE TESTING REQUIREMENTS

1. 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.]
2. 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.]
3. Calculation of Emission Rate: 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.]
4. Applicable Test Procedures [Rule 62-297.310(4), F.A.C.]
   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.

5. Determination of Process Variables [Rule 62-297.310(5), F.A.C.]

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.

6. Sampling Facilities: 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.

7. 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

8. <u>Test Reports</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.

[Rule 62-297.310(8), F.A.C.]

FINAL BACT DETERMINATIONS AND EMISSIONS SUMMARY

PROJECT DESCRIPTION

Georgia-Pacific Consumer Operations LLC operates an existing paper and pulp mill in Palatka using the Kraft sulfate process. In the Kraft process, the digesting liquor (white liquor) is a solution of sodium hydroxide and sodium sulfide that is mixed with wood chips and cooked under pressure. The spent liquor, known as weak black liquor, is concentrated and sodium sulfate is added to make up for chemical losses. The black liquor solids (BLS) are burned in the recovery furnace to produce a smelt of sodium carbonate and sodium sulfide. The smelt is dissolved in water to form green liquor to which quicklime (calcium oxide) is added to convert the sodium carbonate back to sodium hydroxide, which reconstitutes the cooking liquor. The spent lime cake (calcium carbonate) is recalcined in a rotary lime kiln to produce quicklime, which is used to convert the green liquor to cooking liquor. Other steam and energy needs are met by the power boilers, which burn a variety of fuels including oil and natural gas.

This permit authorizes the following major modifications: permanent shutdown of the No. 4 Power Boiler (EU-014); conversion of the No. 5 Power Boiler (EU-015) to natural gas; replacement of the hot-end shell and coolers for the No. 4 Lime Kiln (EU-017); extensive tube replacement and the addition of a fourth level of over-fire air for the No. 4 Recovery Boiler (EU-018); and, the addition of a crystallizer with associated storage/flash tank and modifications to the two existing concentrators associated with the No. 4 multiple effect evaporator set (EU-032).

The permittee conducted a PSD netting analysis based on contemporaneous emissions increases and decreases to avoid PSD preconstruction review for sulfur dioxide (SO_2), sulfuric acid mist (SAM), and total reduced sulfur (TRS). The project is subject to PSD preconstruction review for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM), and volatile organic compounds (VOC). For this permit, the Department determined the Best Available Control Technology (BACT) for the following units: the No. 5 Power Boiler (CO and VOC); the No. 4 Lime Kiln (CO, NO_X, PM, and VOC); and the No. 4 Recovery Boiler (CO, NO_X, PM, and VOC). The No. 4 Combination Boiler is currently under PSD preconstruction review in Project No. 1070005-045-AC for CO, NO_X, PM, and VOC. Throughout this appendix particulate matter emissions are referred to as PM emissions, which serve as a surrogate for regulating $PM_{2.5}$ and PM_{10} emissions.

FINAL BACT DETERMINATIONS

For this project, the applicant conducted a PSD netting analysis that included all contemporaneous emissions increases and decreases. In accordance with Rule 62-212.400 (PSD), F.A.C., the Department establishes the following standards as BACT for CO, NO_X, PM, and VOC emissions.

Pollutant	BACT Standards	Control Technology	Monitoring
No. 5 Power Boiler			
CO [a]	0.185 lb/MMBtu and 105.2 lb/hour	good combustion design and practices for firing natural gas	annual tests
VOC [a]	CO is surrogate standard		no tests required
No. 4 Lime Kiln			
CO [b]	69.0 ppmvd at 10% O_2 and 16.3 lb/hour	good combustion design and practices	annual tests
NO_X	140.0 ppmvd at 10% O_2 and 54.2 lb/hour	good combustion design and practices	annual tests
Opacity	Due to wet plume, scrubber pressure differential and flow rate are continuously monitored.		
PM	0.55 lb/ton processed and 22.9 lb/hour	cyclones and wet venturi scrubber	annual tests
VOC [b]	70.0 ppmvd at 10% O_2 and 9.4 lb/hour	good combustion design and practices	annual tests
No. 4 Recovery Boiler			
CO [c]	400.0 ppmvd @ 8% O_2 and 512.7 lb/hour	good combustion design and practices	CEMS
NO_X [c]	80.0 ppmvd @ 8% O_2 and 168.5 lb/hour	four-level over-fire air system	CEMS
Opacity [d]	20%, 6-minute averages	electrostatic precipitator	COMS
PM	0.030 grains/dscf @ 8% O_2 and 75.6 lb/hour	electrostatic precipitator	annual tests
VOC [e]	0.20 lb/ton of BLS and 21.0 lb/hour	good combustion design and practices	initial/renewal tests

a. For the No. 5 Power Boiler, only CO and VOC emissions will increase after converting to natural gas. All other pollutants will decrease.

b. For the No. 4 Lime Kiln, the testing frequency may be reduced to testing prior to renewal of the operating permit if consecutive tests show emissions below 50% of the emissions standard. CO and VOC emissions are expected to be low due to relatively high kiln temperature and a long residence time. EPA Method 25A used to determine total hydrocarbons measured as methane.

c. For the No. 4 Recovery Boiler, the CO and NO_X standards are based on a 30-day rolling CEMS average excluding emissions data collected during startup and shutdown. For the first 180 days after certifying the CEMS, CO emissions shall not exceed 800.0 ppmvd @ 8% O_2 and 1025.4 lb/hour based on a 30-day rolling CEMS average, excluding data collected during startup and shutdown. The purpose of this interim standard is to provide sufficient time to develop good combustion practices for the four-level overfire air system.

d. For the No. 4 Recovery Boiler, the opacity standard applies once the electrostatic precipitator is placed in service during startup.

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 and the Final Determination issued concurrently with this final PSD air construction permit.

OTHER EMISSIONS STANDARDS

This permit establishes the following additional standards that allow the project to avoid PSD preconstruction review for NO_X, SAM, SO_2, and TRS.

Pollutant	Standards	Monitoring
No. 5 Power Boiler		
NO_X	0.125 lb/MMBtu and 71.1 lb/hour	annual tests
No. 4 Lime Kiln		
SO_2	16.9 ppmvd @ 10% O_2 and 9.1 lb/hour	annual tests
TRS	25.1 tons per year, 12-month rolling CEMS total	CEMS
No. 4 Recovery Boiler		
SO_2	153.9 tons per year, 12-month rolling CEMS total	CEMS
TRS	34.2 tons per year, 12-month rolling CEMS total	CEMS

EMISSIONS SUMMARY

Pollutant	Annual Potential Emissions, tons/year		
	No. 5 Power Boiler[a]	No. 4 Lime Kiln	No. 4 Recovery Boiler
CO	460.8	71.4	2245.6
NO_X	311.4	237.4	738.0
PM	18.9	100.3	331.1
SO_2	1.5	39.9	153.9
TRS	Negligible	25.1[b]	34.2
VOC	13.7	41.2	92.0

a. Emissions from the No. 5 Power Boiler are based on firing 100% natural gas.

b. Based on current TRS standard in Title V permit.

The No. 4 Recovery Boiler (EU-018) is subject to the following requirements for the new continuous emissions monitoring systems (CEMS) required for CO and NO_X emissions. The unit also has existing CEMS for SO_2 and TRS emissions and a continuous opacity monitoring systems (COMS).

CEMS OPERATION PLAN

1. CEMS Operation Plan: The permittee shall create and implement a plan for the proper installation, calibration, maintenance, and operation of each CEMS required by this permit. The permittee shall submit the CEMS Operation Plan to the Bureau of Air Monitoring and Mobile Sources for approval prior to CEMS installation. The CEMS Operation Plan shall become effective 60 days after submittal or upon its approval. If the CEMS Operation Plan is not approved, the permittee shall submit a new or revised plan for approval. *{Permitting Note: The Department maintains both guidelines for developing a CEMS Operation Plan and example language that can be used as the basis for the facility-wide plan required by this permit. Contact the Emissions Monitoring Section of the Bureau of Air Monitoring and Mobile Sources at 850/488-0114.}* [Rule 62-4.070(3), F.A.C.]

MONITORS, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

2. Span Values and Dual Range Monitors: The permittee shall set appropriate span values for the CEMS based on the emissions standards and range of operation. If necessary, the permittee shall install dual range monitors in accordance with the CEMS Operation Plan. [Rule 62-4.070(3), F.A.C.]

3. Diluent Monitor: If required by permit to correct the CEMS output to the oxygen concentrations specified in the applicable emissions standard, the permittee shall either install an oxygen monitor or install a CO_2 monitor and use an appropriate F-Factor computational approach. [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

4. Moisture Correction: If necessary, the permittee shall install a system to determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

5. Continuous Flow Monitor: For compliance with mass emission flow rate standards, the permittee shall install a continuous flow monitor to determine the stack exhaust flow rate. The flow monitor shall be certified pursuant to 40 CFR Part 60, Appendix B, Performance Specification 6. Alternatively, the permittee may install a fuel flow monitor and use an appropriate F-Factor computational approach to calculate stack exhaust flow rate. *{Permitting Note: The CEMS Operation Plan will contain additional details and procedures for CEMS installation.}* [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

6. Performance Specifications: The permittee shall evaluate the "acceptability" of each CEMS by conducting the appropriate performance specification. CEMS determined to be "unacceptable" shall not be considered "installed" for purposes of meeting the timelines of this permit. For CO monitors, the permittee shall conduct Performance Specification 4 of 40 CFR Part 60, Appendix B. For NO_X monitors, the permittee shall conduct Performance Specification 2 of 40 CFR Part 60, Appendix B. [Rule 62-4.070(3), F.A.C.]

7. Quality Assurance: The permittee shall follow the quality assurance procedures of 40 CFR Part 60, Appendix F. For CO, the required relative accuracy test audit (RATA) tests shall be performed using EPA Method 10 in Appendix A of 40 CFR Part 60. For NO_X, the RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR Part 60. [Rule 62-4.070(3), F.A.C.]

CALCULATION APPROACH FOR SIP COMPLIANCE

8. CEMS for Compliance: Once adherence to the applicable performance specification for each CEMS is demonstrated, the permittee shall use the CEMS to demonstrate compliance with the applicable emission standards as specified by this permit. [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

9. CEMS Data: Each CEMS shall monitor and record emissions during all operations and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments, and span adjustments. [Rule 62-4.070(3), F.A.C.]

10. Operating Hours and Operating Days: For purposes of this Appendix, the following definitions shall apply. An hour is

the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit. [Rule 62-4.070(3), F.A.C.]

11. 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.

    a. Hours that are not operating hours are not valid hours.

    b. For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

    [Rule 62-4.070(3), F.A.C.]

12. Calculation Approaches: The permittee shall implement the calculation approach specified by this permit for each CEMS, as follows:

    a. *Daily Averages*: A daily average shall be calculated and recorded for each operating day as the arithmetic average of all valid hourly averages occurring from midnight to midnight.

    b. *Rolling 30-day Average*. Compliance with the 30-day rolling average shall be determined after each operating day by calculating and recording the arithmetic average of all valid hourly averages for the previous 30 operating days (compliance period).

    c. *Rolling 12*-month Average:

    d. *Rolling 12*-month Totals:

    [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

13. Minimum Valid Hours: At least one valid hourly average shall be used to calculate the emissions over any averaging period specified by this permit. One valid hourly average shall be sufficient to calculate the emissions over any averaging period. [Rule 62-4.070(3), F.A.C.]

MONITOR AVAILABILITY

14. Monitor Availability: Monitor availability shall be calculated on a quarterly basis for each emission unit as the number of valid hourly averages obtained by the CEMS, divided by the number of operating hours, times 100%. The monitor availability calculation shall not include periods of time where the monitor was functioning properly, but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit, or relative accuracy audits (RAA). Monitor availability for each CEMS shall be 95% or greater in any calendar quarter. Monitor availability shall be reported in the quarterly excess emissions report. In the event 95% availability is not achieved, the permittee shall provide the Department 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. [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

15. Definitions:

    a. *Excess Emissions* (under the Florida SIP) are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction.

    b. *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.

c. *Shutdown* means the cessation of the operation of an emissions unit for any purpose.

d. *Malfunction* means 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.

[Rule 62-210 (Definitions), F.A.C.]

16. 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. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rules 62-210.700(4), F.A.C.]

17. Data Exclusion for SIP Compliance: As per the procedures in this condition, limited amounts of CO and NO_X CEMS emissions data may be excluded from the corresponding compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions replace the provisions in Rule 62-210.700(1), F.A.C.

a. *Excess Emissions.* For purposes of SIP-based permit limits, excess emissions data collected during periods of startup and shutdown may be excluded from compliance calculations as allowed by the permit standards.

b. *Limiting Data Exclusion.* If the compliance calculation using all valid CEMS emission data (as defined in this Appendix) indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

c. *Event Driven Exclusion.* The excess emissions must occur due to an underlying event (startup or shutdown). If there is no underlying event, then no data may be excluded.

d. *Continuous Exclusion.* Data shall be excluded on a continuous basis per event. Data from discontinuous periods shall not be excluded for the same underlying event.

e. *Reporting Excluded Data.* These procedures for excluding SIP-based excess emissions from compliance calculations are not necessarily the same procedures used for "excess emissions" as defined by federal rules. Semiannual reports required by this permit shall indicate the duration of data excluded from SIP compliance calculations as well as the number of excess emissions as defined in the applicable federal rules.

{Permitting Note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.} [Rules 62-212.400 (BACT) and 62-210.700(4), F.A.C.]

18. Notification Requirements: The permittee shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate non-compliance for a given averaging period.

CALCULATING AND REPORTING ANNUAL EMISSIONS

19. CEMS for Calculating Annual Emissions: As defined by this Appendix, all valid data shall be used when calculating annual emissions.

a. Annual emissions shall include data collected during startup, shutdown, and malfunction periods.

b. Annual emissions shall include data collected during periods when the emission unit is not operating, but emissions are being generated (for example, firing fuel to warm up a process for some period of time prior to the emission unit's "official" startup).

c. Annual emissions shall not include data from periods of time where the monitor was functioning properly but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit, or RAA. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

d. Annual emissions shall not include data from periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

20. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hour block average that begins at the top of each hour. For each hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the permittee shall account for emissions during that hour using site-specific data to generate a reasonable estimate of the 1-hour block average.

21. Emissions Calculation: Annual emissions shall be calculated as the sum of all valid emissions occurring during the year.

22. Reporting Annual Emissions: The permittee shall use data from each required CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rules 62-210.370(3) and 62-212.300(1)(e), F.A.C. [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

APPENDIX G. ON-SPECIFICATION USED OIL REQUIREMENTS

The permittee shall comply with the following requirements for on-specification used oil.

1. Specifications for Used Oil: Only "on-specification" used oil containing a PCB concentration of less than 50 ppm shall be fired at this facility.

   a. "On-specification" used oil is defined as used oil that meets the specifications of 40 CFR 279 (Standards for the Management of Used Oil) as listed below.

Constituent/Property	Allowable Level
Arsenic	5 ppm, maximum
Cadmium	2 ppm, maximum
Chromium	10 ppm, maximum
Lead	100 ppm, maximum
Total Halogens	1000 ppm, maximum
Flash point	100° F, minimum

   Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil. The firing of off-specification used oil at this facility is prohibited.

   b. Used oil containing a PCB concentration of 50 ppm or more shall not be fired at this facility and shall not be blended to meet this requirement.

   c. On-specification used oil with a PCB concentration of 2 ppm to less than 50 ppm shall be fired only at normal unit operating temperatures and shall not be fired during periods of startup or shutdown.

   d. On-specification used oil with a PCB concentration of 2 ppm or less may be fired at any time.

   e. On-specification used oil shall meet the maximum sulfur content specified in the permit.

   [40 CFR 279.61]

2. Used Oil Certifications: For each delivery of used oil, the owner or operator shall receive from the marketer a certification that the used oil meets the specifications for "on-specification" used oil and that it contains a PCB concentration of less than 50 ppm. This certification shall also describe the basis for the certification, such as analytical results. Used oil to be fired for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs. Note that a claim that used oil does not contain quantifiable levels of PCBs (<2 ppm) must be documented by analysis or other information. The first person making the claim that the used oil does not contain PCBs is responsible for furnishing the documentation. The documentation can be tests, personal or special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the used oil contains no detectable PCBs. [40 CFR 761.20]

3. Notification to Marketers: Before accepting from each marketer the first shipment of on-specification used oil with a PCB concentration of 2 to less than 50 ppm, the owner or operator shall provide each marketer with a one-time written and signed notice certifying that the owner or operator will fire the used oil in a qualified combustion device and must identify the class of combustion device. The notice must state that EPA or a RCRA-delegated state agency has been given a description of the used oil management activities at the facility and that an industrial boiler or furnace will be used to fire the used oil with a PCB concentration of 2 to 49 ppm. The description of the used oil management activities may be submitted to the Administrator, Hazardous Waste Regulation Section, Florida Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, FL 32399-2400. [and 40 CFR 761.20(e)]

4. Sampling and Analysis:

   a. If the owner or operator does not receive certification from the marketer as described above, the owner or operator shall sample and analyze each batch of used oil to be fired for the following parameters: arsenic, cadmium, chromium, lead, total halogens, flash point, PCBs, and percent sulfur content by weight, ash, and BTU value (BTU per gallon).

b. If the owner or operator receives the required certification from the marketer, the owner or operator shall sample at least one delivery of used oil received each calendar quarter and analyze the sample for arsenic, cadmium, chromium, lead, total halogens, flash point, PCBs, and percent sulfur content by weight, ash, and BTU value (BTU per gallon).

c. Sampling and analysis shall be performed using approved methods specified in latest edition of EPA Publication SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods.

d. If the analytical results show that the used oil does not meet the specifications for on-specification used oil, or that it contains a PCB concentration of 50 ppm or greater, the owner or operator shall immediately cease firing the used oil. The owner or operator shall also immediately notify the appropriate Compliance Authority of the analytical results and indicate the proposed means of disposal of the used oil.

[Rule 62-4.070(3), F.A.C.; 40 CFR Parts 279 and 761]

5. Used Oil Recordkeeping Required: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Compliance Authority:

a. Within 15 days following each calendar month, record the gallons of on-specification used oil received and fired during the previous calendar month and the previous 12 calendar months.

b. The name and address of all marketers delivering used oil to the facility.

c. Copies of the marketer certifications and any supporting information.

d. If claimed, documentation that the used oil contains less than 2 ppm of PCBs, including the name and address of the person making the claim.

e. Results of any sampling/analyses conducted.

f. A copy of the notice to EPA and a copy of the one-time written notice provided to each marketer.

[Rule 62-4.070(3), F.A.C.; 40 CFR 279.61; and, 40 CFR 761.20(e)]

6. Used Oil Reporting Required: Within 30 days following each calendar quarter, the owner or operator shall submit to the appropriate Compliance Authority, the analytical results and the total amount of on-specification used oil received and fired during the quarter. [Rule 62-4.070(3), F.A.C.; 40 CFR Parts 279 and 761]

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Phone#: 904-807-3235

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

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(386) 325-2001

March 15, 2007

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MAR 16 2007
BUREAU OF AIR REGULATION

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

Re: Project No. 1070005-038-AC PSD-FL-380
Modification of the No. 4 Recovery Boiler, No. 4 Lime Kiln and No. 4 Combination Boiler
Response to Request for Additional Information No. 3

Dear Mr. Koerner:

Please find enclosed five copies of the following attachments that were referenced but not included in the referenced document of March 14, 2007:

- Table 1-1 Contemporaneous Emissions with Power Boiler on Natural Gas
- Figure 1 – Simplified PFD for HVLC and LVHC gases

Sincerely,

Ron

Ron Reynolds, Environmental Engineer
Palatka Operations

cc: W. Galler, T. Champion, T. Wyles, S. Matchett, K.Wahoske, M. Curtis

Georgia-Pacific

COUNTY ROAD #216
FL180
PALATKA, FL 32178

Total pages: 13

To:	Bruce Mitchell	Location:	
Company: 9533		Fax:	+1 (850) 921-

From:	Curtis, Michael	Return Fax:	207-827-0676
Date:	4/5/2007	Phone:	(386) 329-0918
Subject:	FW: BACT Analysis for No. 5 Power Boiler		

Please visit gp.com/supplier for important supplier information

Jeff,

Please find enclosed G-P Palatka's BACT analysis for CO for the #5 Power Boiler. This documentation will be submitted to the Department as a formal submittal via the US mail.

Mike Curtis

Environmental Superintendent

Palatka Mill Evironmental Division

(386)-325-0918

BEST AVAILABLE CONTROL

TECHNOLOGY ANALYSIS

No. 5 POWER BOILER

BACKGROUND

Both the U. S. Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection (FL DEP) require that Best Available Control Technology (BACT) be applied to control emissions from a proposed new or modified source that triggers review under the federal Prevention of Significant Deterioration (PSD) regulations. In July 2006, the Mill submitted a combined PSD permit application for the Nos. 4 Lime Kiln, Recovery Boiler, and Combination Boiler. In order to address a PSD BACT issue related to sulfuric acid mist (SAM) emissions from the three pieces of process equipment, the Mill requested FL DEP to incorporate emission reductions from a separate project for the No. 5 Power Boiler into the netting table for the Nos. 4 Lime Kiln, Recovery Boiler, and Combination Boiler.

The No. 5 Power Boiler project will involve the conversion of this boiler from its current configuration of burning 100% No. 6 fuel oil to 100% natural gas by the end of 2007. This project is being done voluntarily by the Mill in order to exempt the No. 5 Power Boiler from the Best Available Retrofit Technology requirements. By implementing the changeover to burning 100% natural gas, future potential sulfur dioxide (SO_2) and SAM emissions from the No. 5 Power Boiler will be significantly reduced from the past actual emissions. By incorporating the emission reductions into the PSD netting table for the No. 4 Lime Kiln, No. 4 Recovery Boiler, and No. 4 Combination Boiler, both SO_2 and SAM emissions will be reduced to a level well below the respective PSD applicability levels for both of these pollutants. As a result, neither SO_2 or SAM emissions will trigger PSD. However, PSD is triggered for CO emissions as a result of the combined PSD project and the FL DEP has requested the Mill to perform a BACT analysis for CO emissions from the No. 5 Power Boiler.

The No. 5 Power Boiler will be equipped with low-NO_x gas-fired burners rated at 0.1 lbs/MM Btu. The resulting CO emission rate for the low-NO_x burners will be 0.185 lbs/MM Btu, based on the latest engineering information.

With regard to the state rules, BACT is defined as follows:

> *"Best Available Control Technology" means an emission limitation (including a visible emissions standard) based on the maximum degree of reduction for each pollutant emitted from or which results from the new or modified emissions unit which the Department on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such emissions unit through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combination techniques for control of each pollutant. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under40 CFR Part 60 and 61 or any applicable emission standard established by the Department. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit 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 emission reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*

The requirements for BACT were promulgated within the framework of the PSD regulations in the 1977 Amendments to the Clean Air Act (CAA) [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in the EPA's Guidelines for Determining Best Available Control Technology (BACT) (EPA, 1978) and in the PSD Workshop Manual (EPA, 1980 and 1990 draft). EPA promulgated these guidelines to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980):

BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis.

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed or modified facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the facility. BACT must, as a minimum, demonstrate compliance with the New Source Performance Standards (NSPS) for a source (if applicable). A cost-benefit analysis of the materials, energy, economic penalties, and the environmental benefits associated with a control system may also be necessary. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a bottom-up approach, consistent with the BACT Guidelines and PSD Workshop Manual, has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program, including the adoption of a new "top-down" approach to BACT decision-making.

The top-down BACT approach essentially starts with identification of the most stringent (or top) technology and emissions limits that have been applied elsewhere to the same, or a similar source category (Step 1). The applicant must next provide a basis for eliminating this technology in favor of the next most stringent technology or propose to apply the top technology (Step 2). Elimination of control alternatives may be based on technical and/or economic infeasibility. Such decisions are made on the basis of physical differences (*e.g.*, fuel type, etc.), location differences (*e.g.*, availability of water, etc.), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed/modified facility and the facility on which the control technique was applied previously must be justified. The next step consists of ranking the remaining control technologies by control effectiveness (Step 3). Next, an evaluation of the most effective controls is conducted and documented (Step 4). Lastly, the BACT technology is selected from the list in the previous step (Step 5).

The EPA issued a draft guidance document on the top-down approach entitled, Top-Down Best Available Control Technology Guidance Document (EPA, 1990). However, to date, EPA has not promulgated the top-down approach for determining BACT.

In selecting one of the alternatives in technology, the applicant should consider application of flue gas treatment, fuel treatment and processes, and techniques that are inherently low polluting and are economically feasible. In cases where technological or economic limitations on the application of measurement techniques would make the imposition of an emission limitation infeasible, a design, operating, equipment, or work practice standard may be provided by the source. The BACT analysis shall include the following steps:

Step 1. Identify all potential control strategies.

Step 2. Eliminate technically infeasible options.

The demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical and engineering principles, that the technical difficulties would preclude the successful use of the control option on the emission unit under review.

Step 3. Rank remaining control technologies by control effectiveness.

The ranking should include relevant information including:

(a) control effectiveness
(b) expected emission rate
(c) expected emission reduction
(e) energy impacts
(f) environmental impacts
(g) economic impacts

Step 4. Evaluate most effective controls and document results.

The evaluation should include case-by-case consideration of energy, environmental and economic impacts. If top option is not selected as BACT, the evaluation should consider the next most effective control option.

Step 5. Select BACT.

BACT is the most effective option not rejected in Step 4.

The FL DEP's requirements for a BACT analysis are equivalent to the EPA's top-down approach. For this reason, this BACT document is consistent with both approaches.

BACT ANALYSIS-NO. 5 POWER BOILER FIRING 100% NATURAL GAS

This analysis is being conducted to determine the best available control technology for CO emissions from the No. 5 Power Boiler when burning 100% natural gas.

Step 1a-Identification of Control Technologies

Carbon Monoxide (CO) Emissions

There are several approaches that can be used to reduce carbon monoxide emissions from boilers. The first involves combustion modification techniques and a second approach involves the addition of post-combustion controls. The third technique involves the use of "good combustion practices". All three of these approaches are discussed below.

Combustion Modification-Overfire Air

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

The use of an overfire air system in a natural gas-fired boiler can reduce CO emissions up to 25% compared to CO emission levels in boilers without an overfire air system.

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

Post-Combustion Control-Oxidation Catalyst

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

The catalyst material for a CO oxidation catalyst system can be purchased from a number of catalyst manufacturers in the United States. However, the integration of the catalyst into a working module for installation on boiler exhaust gases may need to be handled by a separate company. These conventional catalysts work best when clean fuel(s) are being burned, such as natural gas, propane, or No. 1 or No. 2 fuel oil.

Good Combustion Practices

Another approach that can be used to minimize CO emissions from boilers is the use of "good combustion practices". Examples of "good combustion practices" for a natural gas-fired boiler include operator practices, maintenance practices, maintaining proper stoichiometric fuel-to-air ratios, monitoring of fuel quality and consistency, temperature, and combustion air distribution. Additionally, a start-up, shutdown, and malfunction plan should be developed and followed to ensure that emissions are minimized to the extent practicable during these periods of operation. All of these factors can affect the pollutant emission rate generated by the boiler, as well as the boiler combustion efficiency.

By following these "good combustion practices", CO emissions will be minimized. There is no specific percent reduction that can be given for using good combustion practices, however, without their use, CO emissions from a natural gas-fired boiler will increase significantly, by a factor of 100% or more, as compared to a boiler that uses good combustion practices. It is in the Mill's interest to use good combustion practices so that boiler efficiency is not compromised.

Step 1b-Identification of Control Technologies-Review of RACT/BACT/LAER Clearinghouse (RBLC)

Searches of the RACT/BACT/LAER Clearinghouse (RBLC) were conducted to identify technologies for the control of emissions from boilers with natural gas-fired burners. Searches were only conducted for RBLC determinations added during or after January 1980 and for large industrial sized boilers in service at pulp & paper mills. Listings of control technologies for boilers other than those at pulp & paper mills are too numerous to list and may not be representative of the types of boilers used in the pulp & paper industry. The RBLC technology listings are provided in Table 1, attached, and are summarized below.

> Table 1– good combustion control, none (or no controls), good combustion design and proper combustion techniques, efficient combustion, air/fuel ratio control.

Step 1c-Identification of Control Technologies-Review of Technologies in Use at Georgia-Pacific Corporation Facilities

Pulp & Paper Mills-Georgia-Pacific operates 18 pulp & paper mills in the United States. There are about 31 boilers at these facilities that are capable of burning natural gas, either alone, or in combination with other fuels. Of these 31 boilers, 6 have low-NO_x burners in place to reduce NO_x emissions and several others have overfire air systems to improve combustion efficiency and reduce CO emissions. There are no other types of pollution controls used for the natural gas burners since natural gas is the cleanest fuel available and it generates the smallest amount of pollution when combusted.

Step 2- Technical Feasibility Analysis

CO Control Technologies for Natural Gas-Fired Burners

In addition to the use of overfire air systems, the main control technology utilized for minimizing CO emissions from natural gas-fired burners is good combustion practices and the use of natural gas as clean fuel. Natural gas is the only fuel that will be utilized in the No. 5 Power Boiler. Good combustion practices and the use of natural gas are technically feasible for the No. 5 Power Boiler. An overfire air system is also technically feasible for the No. 5 Power Boiler, however, GP has obtained information from at least one vendor who has stated that its burners will minimize CO emissions to the same level of control as if an overfire air system were installed, but without the need to install an overfire air system.

Oxidation catalysts can also be used to remove CO emissions from a boiler with natural gas burners. A cost effectiveness analysis for an oxidation catalyst system will be performed later as part of this analysis.

Good combustion practices are technically feasible for the No. 5 Power Boiler.

Step 3 – Ranking the Technically Feasible Alternatives to Establish a Control Hierarchy

The next step in the BACT analysis is to rank the various control options not eliminated in the previous step. Table 2 below presents the remaining technologies.

TABLE 2 CO CONTROL TECHNOLOGY HIERARCHY

CONTROL TECHNOLOGY	CONTROL EFFICIENCY
Oxidation Catalyst	70-95%
Overfire Air System	Up to 25%
Good Combustion Practices Use of Natural Gas as Clean Fuel	No specific value

Step 4 – Control Effectiveness Evaluation

This step of the BACT process is necessary when the top control is not selected as BACT. Step 4 determines the economic impact of the feasible control options listed in Step 3 and then selects the most appropriate technology as BACT for the No. 5 Power Boiler. The economic analysis is based on cost data supplied by the equipment suppliers, GP experience at other locations, and the use of cost estimating spreadsheets contained in Chapter 2 of EPA's Office of Air Quality Planning & Standards (OAQPS) Control Cost Manual, 6th Edition, January 2002 (Chapter 2-Cost Estimating Methodology).

Oxidation Catalyst

To estimate the cost for the purchase and installation of an oxidation catalyst system to reduce CO emissions from the No. 5 Power Boiler, GP prorated an estimate for a system that was designed for use with a gas turbine at its Old Town, ME Mill in 2001 (GP no longer owns the Old Town, ME Mill). The proration was performed by scaling up the costs based on the ratio of exhaust gas flow between the gas turbine and the No. 5 Power Boiler. The cost for a duct burner was also calculated since the exhaust gas temperature from the No. 5 Power Boiler is not high enough to allow the oxidation catalyst to work properly.

As stated earlier in this report, it is necessary to raise the exhaust temperature of the boiler in order for an oxidation catalyst system to work properly if the exhaust temperature is below the optimum value for the catalyst to work effectively. Since the No. 5 Power Boiler has an economizer section that recovers heat, the exhaust gas temperature is only 450 degrees Fahrenheit (°F). In order to work effectively, the exhaust gas temperature must be raised to approximately 800 °F for the catalyst to optimally reduce CO emissions. The use of a duct burner to raise the exhaust temperature from 450 °F to 800 °F, would require the Mill to burn approximately 420.5 MM ft^3 of natural gas per year at a cost of more than $3.0 MM per year (based on gas cost of $8.95/MM ft^3 Feb-2007)(see Addendum at end of this report). The use of a duct burner would also increase CO emissions by approximately 19.3 tons/yr. The potential CO emission rate from the boiler is 461 tons per year. Therefore, the total tons of CO generated would be equal to 461 + 19.3 = 480.3 tons/yr. Assuming a minimum CO reduction of 90% with the use of the CO catalyst system, 432.3 tons of CO would be removed. This equates to a cost effectiveness of $8,454/ton as shown in Table 3.

This value is above any reasonable level of cost for reducing CO emissions. Therefore, it is economically infeasible to use an oxidation catalyst system to remove CO emissions. It is also a waste of a valuable energy resource (natural gas). In addition, the use of a duct burner increases the amount of CO due to the combustion of natural gas. For these reasons, an oxidation catalyst system for the No. 5 Power Boiler will not be discussed any further as part of this BACT analysis.

Overfire Air System

A cost effectiveness analysis for an overfire air system is not being performed as GP will be purchasing a natural gas burner system for the No. 5 Power Boiler without an overfire air system. However, the burner system that is installed will minimize CO emissions to a level equivalent to what would be possible with the installation of an overfire air system. For this reason, it is not necessary to perform a cost effectiveness evaluation for an overfire air system.

Good Combustion Practices

GP will utilize good combustion practices for the No. 5 Power Boiler at all times when the unit is in operation. For this reason, it is not necessary to perform a cost effectiveness evaluation for the use of good combustion practices.

Step 5 – Select BACT

CO Emissions

GP believes that boiler design and good combustion practices for the No. 5 Power Boiler represents BACT. This is equivalent to the "highest" BACT control technologies listed in Table 1 from the RBLC which indicates boiler design or good combustion practices. As discussed in Step 4 of this analysis, it is economically infeasible to use an oxidation catalyst system. Also as discussed in Step 4 of this analysis, GP will install a burner system that meets a CO emission level equivalent to that which would be achieved through the use of an overfire air system, but without actually installing an overfire air system.

The BACT emission limits for CO emissions contained in Table 1 range from 0.04 lb/MM Btu to 1.13 lb/MM Btu. The variation in emission rates is due to a number of variables, including boiler size and physical configuration, combustion design, year of manufacture, and whether or not the CO emission rate is based on original boiler design or retrofit design.

The Mill agrees to a CO BACT permit limit of 105.2 lbs/hr (or 0.185 lb/MM Btu), which is based on a vendor-supplied emission factor. This is the best CO emission rate attainable for the No. 5 Power Boiler based on the fact that the new, gas-fired burners will be designed with low-NO_x technology which results in a slightly higher CO emission rate than if the boiler was not equipped with low-NO_x burners. Additionally, the predicted CO emission rate is based on retrofitting an existing boiler with natural gas-fired burners, a fuel that the boiler was not originally designed to burn.

Addendum to BACT Analysis
Oxidation Catalyst for CO Removal:

To determine the amount of energy (H) it takes to heat the flue gas from 450 °F to 800 °F:

$H = m\,C_p\,(t_2 - t_1)$ Where: H = heat input, Btu/hr
m = mass flow rate of flue gas, lbs/hr = 505,500 lb/hr
C_p = specific heat of flue gas, Btu/lb-°F
$t_2 - t_1$ = 800-450 = 350 °F

Determine Cp for flue gas from Figure 3-12 of Perry's Chemical Engineers Handbook, 4th Edition, assume flue gas similar to air:

C_p = 0.25 Btu/lb-°F @ 800 °F

H = 505,500 lbs/hr x 0.25 Btu/lb-°F x 350 °F = 44,231,250 Btu/hr

Assuming a heat content of 1,000 Btu/ft^3 for natural gas, it will take 44,231,250 / 1,000 / 1.0E+06 = 0.044 MM ft^3/hr of natural gas to heat the flue gas from 450 °F to 800 °F. At a cost of \$8.95/MM Btu for natural gas at the Mill, the hourly cost to raise the flue gas temperature to 800 °F is equal to 44.23125 MM Btu/hr x \$8.95/MM Btu = \$395.87/hr, or an annual cost of \$395.87/hr x 8,760 hr/yr = \$3,467,818 per year.

Natural gas-fired burners have a combustion efficiency of approximately 85%. Therefore, it will take a 44.23125 MM Btu/hr/0.85 = 52 MM Btu/hr burner to heat the flue gas up to 800 °F.

CO emissions from heating flue gas to 800 °F = (52 MM Btu/hr / 1,000 Btu/ft^3 /1.0E+06) x 0.084 lb/MM Btu (from AP-42, Table 1.4-1, and assuming heat content of gas = 1,000 Btu/ft^3) = 4.4 lb/hr x 8,760 hr/yr /2,000 lb/ton = 19.3 tons CO/yr. These CO emissions are generated in addition to those from the combustion of gas in the boiler, which are equal to 105.2 lbs/hr or 461 tons/yr. Total CO emissions, with the use of an oxidation catalysts system and a duct burner would be equal to 19.3 + 461 = 480.3 tons/yr.

TABLE 1
SUMMARY OF EPA CLEARINGHOUSE BACT DETERMINATIONS FOR
POWER BOILERS FIRING NATURAL GAS
CO EMISSIONS

COMPANY NAME	STATE	PERMIT NUMBER	PERMIT ISSUE DATE	PROCESS DESCRIPTION	BOILER SIZE	CONTROL DEVICE DESCRIPTION	EMISSION LIMIT	BASIS
GEORGIA-PACIFIC CORPORATION	MS	1500-00007	07/09/2003	POWER BOILER	766 MM BTU/HR	NONE	30.4 LB/HR (0.04 LB/MM BTU)	BACT-PSD
WEYERHAEUSER COMPANY	AL	109-0001-X017, X018, X019	11/15/2002	BOILER, NATURAL GAS	300 MM BTU/HR	NONE	30.0 LB/HR (0.1 LB/MM BTU)	BACT-PSD
GEORGIA-PACIFIC CORPORATION	LA	PSD-LA-581 (M-2)	01/25/2002	POWER BOILER NO. 5	987 MM BTU/HR	GOOD EQUIPMENT DESIGNS AND PROPER COMBUSTION TECHNIQUES	76.3 LB/HR (0.077 LB/MM BTU)	BACT-PSD
GEORGIA-PACIFIC CORPORATION	LA	PSD-LA-581 (M-2)	01/25/2002	POWER BOILER NO. 2	65.5 MM BTU/HR	GOOD EQUIPMENT DESIGNS AND PROPER COMBUSTION TECHNIQUES	36.8 LB/HR (0.56 LB/MM BTU)	BACT-PSD
GAYLORD CONTAINER CORPORATION	LA	PSD-LA-657	09/18/2001	BOILER NO. 10C	797.6 MM BTU/HR	GOOD EQUIPMENT DESIGN & PROPER COMBUSTION TECHNIQUES	898.3 LB/HR (1.13 LB/MM BTU)	BACT-PSD
RAYONIER SPECIALTY PULP PRODUCTS	GA	2631-151-12433	6/16/1997	BOILER, NATURAL GAS-FIRED	352 MM BTU/HR	GOOD COMBUSTION CONTROL	0.09 LB/MM BTU	BACT-PSD
WEYERHAEUSER COMPANY	MS	1680-00044	9/10/1996	BOILER, NATURAL GAS	400 MM BTU/HR	EFFICIENT OPERATION	0.1 LB/MM BTU	BACT-PSD
BOISE CASCADE CORP.	AL	102-0001	5/10/1996	BOILER, NATURAL GAS	346.4 MM BTU/HR	COMBUSTION CONTROL	0.09 LB/MM BTU	BACT-PSD
CHAMPION INTERNATIONAL CORP	FL	PSD-FL-200	03/25/1994	NO. 6 POWER BOILER	533 MM BTU/HR	NONE	0.1 LB/MM BTU	BACT-PSD
WAUSAU PAPERS	WI	93-DCF-070	10/28/1993	BOILER, NATURAL GAS	330 MM BTU/HR	GOOD COMBUSTION	0.12 LB/MM BTU	BACT-PSD
WILLAMETTE INDUSTRIES INC	LA	PSD-LA-562	02/04/1991	BOILER, GAS-FIRED	335 MM BTU/HR	DESIGN & OPERATION	13.4 LB/HR (0.04 LB/MM BTU)	BACT-PSD
GEORGIA-PACIFIC CORPORATION	LA	PSD-LA-544	2/15/1988	BOILER, NATURAL GAS-FIRED	987 MM BTU/HR	AIR/FUEL RATIO CONTROL	0.12 LB/MM BTU	BACT-PSD

TABLE 3 Cost Effectiveness for Using Oxidation Catalyst System to Remove CO Emissions from No. 5 Power Boiler

Cost Items	Cost Factors	2007 dollars
DIRECT CAPITAL COSTS (DCC):		
(1) Purchased Equipment Cost		
(a) Basic Equipment	Based on scaling up GP engineering cost analysis for similar system (14.9% adjustment from 2001 pricing based on CPI index)	$656,155
(b) Freight	0.05 x (1a)	$32,808
(c) Subtotal	(1a..1b)	$688,963
(2) Direct Installation	GP Engineering Estimate	$100,000
Total DCC:	(1) + (2)	$788,963
INDIRECT CAPITAL COSTS (ICC): (a)		
(3) Indirect Installation Costs		
(a) Technology License Fee	included with DCC (1a) above	$0
(b) Engineering & Supervision	included with DCC (2) above	$0
(c) Construction & Field Expenses	included with DCC (2) above	$0
(d) Construction Contractor Fee	included with DCC (2) above	$0
(e) Contingencies	(0.3) x (DCC) (GP Engineering estimate for retrofit)	$236,689
(4) Other Indirect Costs		
(a) Startup & Testing	GP Engineering Estimate	$50,000
(b) Working Capital	30-day DOC	$289,143
Total ICC:	(3) + (4)	$575,832
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	$1,364,795
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor	$33/man-hr x 50 man-hr/yr	$1,650
Operator		$0
Supervisor		$0
(2) Maintenance		
Labor	15% of operating labor	$248
Materials		$0
(3) Costs for natural gas firing in duct burner	505,500 lbs flue gas/hr at 450 °F Heat exhaust gas from 450 °F to 800 °F Cost of natural gas = $8.95/MM Btu	$3,467,818
Total DOC:	(1) + (2) + (3)	$3,469,716
INDIRECT OPERATING COSTS (IOC):		
(5) Overhead	60% of oper. labor & maintenance	$1,139
(6) Property Taxes	1% of total capital investment	$13,648
(7) Insurance	1% of total capital investment	$13,648
(8) Administration	2% of total capital investment	$27,296
Total IOC:	(5) + (6) + (7) + (8)	$55,730
CAPITAL RECOVERY FACTOR (CRF)*:	n=yrs; i = %	0.0944
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	$128,827
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	$3,654,273
POTENTIAL CO EMISSION RATE (TPY) :	Potential Emission Rate = (0.185 lb/MM Btu x 568.9 MM Btu/hr) + 19.3 tons/yr of CO emissions from duct burner	480.3
TOTAL CO REMOVED TPY:	Oxidation catalyst = 90 % reduction in CO emissions	432.3
COST EFFECTIVENESS:	$ per ton of CO removed	$8,454

Notes:
Factors and cost estimates reflect vendor quotations, engineering estimates, and EPA's Cost Control Manual procedures
PEC based on GP engineering data for CO oxidation catalyst system for gas turbine in 2003 with rated exhaust flow of 323,093 lbs/hr
Cost = $365,000 (without installation)

***The CRF is computed according to the standard formula:**

$$CRF = i(1+i)^n/[(1+i)^n-1]$$

where: i = annual interest rate (decimal)
n = control system life (years)

Georgia-Pacific

Palatka Pulp and Paper Operations
Consumer Products Division
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RECEIVED
MAR 15 2007
BUREAU OF AIR REGULATION

March 14, 2007

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

Re: Project No. 1070005-038-AC PSD-FL-380
Modification of the No. 4 Recovery Boiler, No. 4 Lime Kiln and No. 4 Combination Boiler
Response to Request for Additional Information No. 3

Dear Mr. Koerner:

We are in receipt of your request for additional information, dated December 15, 2006, regarding our PSD permit application project to make modifications to the No. 4 Recovery Boiler, No. 4 Lime Kiln, and No. 4 Combination Boiler.

This response addresses questions 1, 3, 4 and 6 of the Department's December 15, 2006 request for additional information. A response to questions 2, 6 and 7 was submitted to FDEP on January 31, 2007. We are revising our January 31 response to question 6, which is why this question is addressed for a second time. GP will respond to question 5 in the near future, once it has determined all pertinent costs for the control of NO_x emissions for the No. 4 Combination Boiler.

This response also addresses a number of questions posed by the Department during a telephone conference call held on February 8, 2007 between Messrs. Bruce Mitchell and Jeff Koerner of the FDEP and Wayne Galler and Mark Aguilar of GP. The conference call was held to discuss a number of issues related to GP's desire to incorporate "past actual" and "future potential" emissions from the No. 5 Power Boiler into the most current PSD netting analysis, as well as GP's strategy for Best Available Retrofit Technology (BART) implementation at the Mill.

For ease of following GP's responses, we have repeated the FDEP's questions prior to the answers.

Sulfuric Acid Mist (SAM) Emissions

1. **The project is significant for sulfuric acid mist emissions and requires a BACT determination. SAM emissions from the No. 4 Lime Kiln result from firing residual oil; however, overall emissions are very low (estimated < 2 tons/year) due to the natural scrubbing action of the lime kiln and possible additional reductions in the venturi scrubber. For the No. 4 Combination Boiler, the control technology review indicates the following technologies are available for the control of SAM emissions: Dry ESPs, wet ESPs and wet scrubbers. Your control technology review for the No. 4 Recovery Boiler also indicates mist eliminators in addition to this equipment. Dry ESPs, wet ESPs, wet scrubbers were eliminated from consideration due to expected high capital costs. Mist eliminators were eliminated from consideration because no actual installations were identified that reduced SAM emissions with mist**

eliminators on a recovery boiler. However, this technology appears transferable. Please provide a cost effectiveness analysis for adding mist eliminators to the No. 4 Recovery Boiler and the No. 4 Combination Boiler.

As stated in the application for the No. 4 Recovery Boiler, reducing SO, emissions will also result in lower SAM emissions. For this reason, the Department will consider reducing the fuel sulfur content of the residual oil in making its BACT determination. Please provide a control technology review for lowering the fuel sulfur content of the residual oil currently being fired to include a cost effectiveness analysis.

Alternatively, provide a combination of fuel consumption/fuel sulfur limits that maintain the net emissions increases below the PSD significant emissions rate for SAM emissions (7 tons/year). Depending on future use, this may be readily achievable because the primary fuels are BI.S for the No. 4 Recovery Boiler and bark/wood for the No. 4 Combination Boiler. In fact, the stated purpose of the modifications to the No. 4 Combination Boiler is to more efficiently combust bark/wood and to displace oil firing.

Answer: The Mill plans to eliminate the use of No. 6 fuel oil in the No. 5 Power Boiler by the end of 2007. The Mill would like to incorporate the No. 5 Power Boiler's "past actual" and "future potential" emission rates into the Netting Table being used in the PSD permit application for the Nos. 4 Lime Kiln, Recovery Boiler, and Combination Boiler. By incorporating the No. 5 Power Boiler's "past actual" and "future potential" emissions into the Netting Table (see attached copy of Table 1-1 from PSD Application and associated emission calculations for the No. 5 Power Boiler), the SAM emissions change for the combined projects will fall well below the PSD applicability threshold of 7 tons per year and as a result, PSD will not be triggered for SAM emissions.

No. 4 Combination Boiler

3. **Prior to our previous request for additional information, representatives from the Bureau of Air Regulation met with representatives from Georgia-Pacific on October 26th. At the meeting, Georgia-Pacific indicated plans to revise the application to show that the modifications to the No. 4 Combination Boiler would not result in any emissions increases over baseline emissions except for CO emissions. Your response did not include such a revision. Please verify that you no longer have such plans to revise the application.**

   Answer: GP no longer plans to revise the PSD application as described.

4. **Your first response to our request for additional information (Item #14) identified the design flow as 230,000 acfm. Item #15 of that response also identified corrected flow rate as 135,400 dscfm @ 10% O_2, which was used to calculate the TRS emissions (page 7 of 7 of the application. "Total Reduced Sulfur, Potential Emissions"). Your second response to our request for additional information (Item #3) identifies the preliminary design flow rate as 317,000 acfm. It appears that the flow rate has changed. Please verify design flow rate from the No. 4 Combination**

Boiler in "acfm" and the corresponding flow rate in "dscfm @ 10% O_2. As necessary, recalculate the potential TRS mass emissions rates and update the applicable application pages.

Answer: As FDEP is aware, the Mill has submitted an application for modifying the No. 4 Combination Boiler so that it will be able to burn larger quantities of wood/bark. As a result of the modifications, the heat input rating for the boiler will be increased from the current value of 512.7 MM Btu/hr to 564 MM Btu/hr, for an increase of about 10%. As a result of the larger heat input and larger fuel firing rates for bark, there will be a corresponding increase in the exhaust gas flow rate when the boiler is operated at its maximum steam load. Based on an assessment prepared by the GP's Utilities Engineering Department, the estimated flow rate of the boiler's exhaust gases under full load at the higher heat input rating will be approximately 317,000 acfm at a temperature of approximately 500 ^{o}F. The exhaust flow rate at standard conditions is estimated to be approximately 135,400 dscfm @ 10% oxygen, or no change from the current standard exhaust gas flow rate. Since this standard flow rate is the same value that was used to estimate the TRS emission rate in the PSD application, no changes in the TRS emission calculations or application forms are necessary.

6. **Based on your last submittal, a new ESP will be installed on the No. 5 Power Boiler. No vendor has yet been selected. As you are aware, the No. 5 Power Boiler has been identified as a "BART-eligible" unit. Please ensure that this new control equipment will be designed and selected in accordance with this upcoming regulatory requirement.**

Answer: Once the Mill starts burning 100% natural gas in the No. 5 Power Boiler, which is planned to occur by the end of 2007, there will be no need to install a new ESP for this unit or continue to use the existing ESP. The modifications to the No. 5 Power Boiler are tentatively scheduled to begin in September 2007. Within 60 days of completing construction, the facility will complete compliance testing of the source.

Responses to Questions Posed by the Department during a Teleconference on February 8, 2007:

Question: The Department wants the Mill to describe the timing for putting the ESP into use to control particulate matter emissions during start-up for the No. 4 Recovery Boiler.

Answer: The ESP for the No. 4 Recovery Boiler is not energized and put into use until the end of the start-up period. This is because during the start-up period, there is a possibility of a spark from an energized ESP starting a fire or causing an explosion inside of the ESP. This can occur because during the start-up period when the boiler is burning 100% No. 6 fuel oil. There is a combination of some uncombusted fuel oil and a higher than normal level of oxygen in the exhaust gases from the boiler which are carried into the ESP. The higher than normal level of oxygen is present in the boiler because it is important to purge combustible gases from the boiler during start-up periods by using large volumes of combustion air. The wire electrodes in the ESP can become coated with the fuel oil and if the ESP is energized, a spark could develop in the ESP, resulting in a fire or explosion. For these reasons, the ESP is not energized until conditions inside the boiler have stabilized, meaning that the combustion temperature has risen to the proper level for steam to be produced and black liquor has begun to be used as a continuous source of fuel to the boiler. At this same time, the amount of fuel oil burned in the boiler is reduced until the boiler is firing 100% black liquor.

To minimize particulate emissions during the start-up period, the Mill utilizes good combustion practices such as maintaining the proper stoichiometric fuel-to-air ratio, monitoring of fuel quality and consistency, and proper temperature and combustion air distribution.

Question: The Department has asked the Mill to specify the SO_2 and NO_x emission limits the No. 4 Recovery Boiler can meet during start-up operations if the existing Title V Permit limits for normal operation are not sufficient.

Answer: Since the No. 4 Recovery Boiler burns 100% No. 6 fuel oil during start-up (no black liquor), the Mill is requesting separate emission limits for SO_2, NO_x, and PM emissions during start-up, without the use of the ESP. These limits should be based on emission factors for a large (>250 MM Btu/hr heat input) fossil-fuel fired industrial boiler contained in Table 1.3-1 of AP-42 and assuming a maximum fuel oil firing rate of 80 gallons per minute with a sulfur content not to exceed 2.35% (wt.). The emission calculations are shown below:

SO_2 (lbs/hr) = (157 x 2.35 % S) lb SO_2/1,000 gal fuel oil fired x (80 gal fuel oil fired/min/1,000 gallons) x 60 minutes/hr = 1,771 lbs SO_2/hr

NO_x (lbs/hr) = 47 lb SO_2/1,000 gal fuel oil fired x (80 gal fuel oil fired/min/1,000 gallons) x 60 minutes/hr = 225.6 lbs NO_x/hr

PM = [(9.19 x 2.35% S) + 3.22] lbs PM/1,000 gal fuel oil fired x (80 gal fuel oil fired/min/1,000 gallons) x 60 minutes/hr = 119.1 lbs PM/hr

PM_{10} = 74.8% of PM (AP-42, Table 10.2-3) = 89.1 lbs/hr

Question: The Department has requested the Mill to provide the number of hours per year that the waste gases from the pulp mill are incinerated in either the No. 4 Combination Boiler or the No. 5 Power Boiler.

Answer: Following is a listing of the hours during 2004 through 2006 that the non-condensable gases (NCGs) and stripper off-gases (SOGs) from the pulp mill were incinerated in either the No. 4 Combination Boiler or the No. 5 Power Boiler. Effective April 2006, all high volume, low concentration (HVLC) gases, also referred to as dilute NCGs (DNCGs), must be burned in an incineration device. For the Palatka Mill, the primary incineration device for the DNCGs is the No. 5 Power Boiler with the No. 4 Combination Boiler as the back-up incineration device:

2004: No. 4 Combination Boiler NCGs-915 hours SOGs-886 hours

2005: No. 4 Combination Boiler NCGs-905 hours SOGs-763 hours
DNCGs-924 hours
No. 5 Power Boiler DNCGs-149 hours

2006 No. 4 Combination Boiler NCGs-1,174 hours SOGs-901 hours
DNCGs-3,436 hours
No. 5 Power Boiler DNCGs-4,920 hours

Question: The Department has requested the Mill to provide the typical time period for a "warm" start up period for the No. 4 Recovery Boiler. The Department also wants the Mill to provide information on the number of actual start-ups during the last 2 years.

Answer: A typical "warm" start-up period for the No. 4 Recovery Boiler is approximately 8 hours. This is opposed to a typical "cold" start up period that may last 24 hours or greater as explained to the FDEP in the response to RAI # 2, dated January 31, 2007. Start-up periods for the No. 4 Recovery Boiler:

	2005	2006
Cold start-ups	1	3
Warm start-ups	3	8

Question: The Department has requested the Mill to provide a simplified process flow diagram (PFD) indicating the primary and back-up control devices used to control emissions from the facility's waste gas streams.

Answer: A simplified PFD has been prepared and is attached as Figure 1.

In a recent teleconference the Department requested the specifications for the low-NO_x natural gas burners proposed for the No. 5 Power Boiler. The Mill's engineering specification for the burners is attached. The manufacturer's specification will be provided when available.

If you have any questions regarding this response, please contact Michael Curtis at 386-329-0918.

I, the undersigned, am the responsible official of the source for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and the data contained in this document are true, accurate, and complete.

Sincerely,

Al Kahm FOR KWW

Keith W. Wahoske
Vice President

Attachment

cc: W. Galler, T. Champion, T. Wyles, S. Matchett, R. Reynolds, M. Curtis - GP

PART 1 - GENERAL

1.1 SCOPE

1.1.1 No. 5 Power Boiler at G-P's Palatka, Florida mill fires No. 6 fuel oil. It is a top hung field-erected boiler furnished by Babcock and Wilcox. It has a pressurized furnace. This boiler will be converted to natural gas firing. The boiler presently has its original burners, manufactured by Forney Engineering. Burner delivery is critical. All items specified in this document shall be at the jobsite no later than September 1, 2007.

1.1.2 Equipment shall be built to all applicable codes and standards including FM standards.

1.1.3 Two drawings are included:

- Front & Sectional Front View of No. 5 Power Boiler, B&W drawing no. 218 72 F-2
- Existing burner arrangement, Forney Engineering drawing 8901-1

1.2 REFERENCED AND INCLUDED GEORGIA PACIFIC SPECIFICATIONS

1.2.1	GE01011-002	General Conditions
1.2.2	GE01014-001	Drafting and Document Standards
1.2.3	ME09914-001	Equipment Balance

1.3 FURNISHED BY SELLER

The following is a list of items to be supplied by the Seller. This list is not intended to be all inclusive; it is only a general list. The Seller is to include all items which are required to constitute a complete unit and system.

1.3.1 Natural gas burner and igniter assemblies including:

1.3.1.1 Natural gas igniters and igniter scanners

1.3.1.2 Main flame scanners

1.3.1.3 All required flex hoses

1.3.1.4 Registers with automatic operators

1.3.1.5 Internal insulation (if required)

1.3.1.6 Tile template for throat (if required)

1.3.2 Factory assembled, rack-mounted burner valve train including:

1.3.2.1 All required safety shutoff valves and vent valves

1.3.2.2 All required limit switches and pressure switches

1.3.2.3 Gas pressure regulators and relief valves

1.3.2.4 All required pressure gauges

1.3.2.5 Included piping

1.3.3 If required, additional equipment to achieve specified NOx emissions

1.3.3.1 FGR fan and motor

1.3.3.2 FGR control damper

1.3.3.3 Flue gas ducting

1.3.3.4 Engineering

1.3.4 Windbox air flow modeling using CFD to optimize air flow

1.4 DRAWINGS

1.4.1 The Seller shall furnish the Engineers with all information, drawings, and instructions required for complete execution of the work. See attached Drawing and Document Requirement Sheet.

1.5 PROPOSAL

The proposal shall include the following information:

1.5.1 Full descriptive literature for each piece of equipment and a schematic outline drawing shall accompany the proposal. The weights of the major pieces of equipment shall also be included.

1.5.2 Normal delivery from date of purchase shall be provided along with options for improving that delivery date.

1.5.3 A listing of all motors furnished with their rated horsepowers and RPM.

1.5.4 The attached tabulation sheets shall be completed by the Seller.

1.5.5 Optional accessories recommended, if any.

1.5.6 Proposal shall include any exceptions to the specifications.

1.6 OPTIONS

1.6.1 Furnish an optional price for including flame rod detection of igniter flames rather than scanners.

PART 2 – DESIGN & MATERIALS

2.1 DESIGN CRITERIA

2.1.1 Design heat input with all burners in operation at 100% Maximum Continuous Rating (MCR): 535.5 million Btu/hr

2.1.2 Steam generation at 100% MCR: 420,000 lb/hr

2.1.3 Individual burner turndown shall be 8:1

2.1.4 Normal boiler operating range is 10% to 100% of MCR

2.1.5 Natural gas HHV=1,050 Btu/CF

2.1.6 Nominal natural gas pressure = 120 psig

2.1.7 NOx Emissions shall not exceed 0.10 lb/10^6 Btu heat input over the specified burner turndown range with any number of burners in operation.

2.1.8 CO Emissions shall not exceed 0.185 lb/10^6 Btu heat input over the specified burner turndown range with any number of burners in operation.

2.1.9 Air leakage ("cooling air") through unused burners shall be minimized through materials of construction and other design features.

2.1.10 When operating, burners shall use a minimum of excess air.

2.2 MATERIALS & CONSTRUCTION

2.2.1 Number of burners: Six total, three rows of two burners per row.

2.2.2 Furnace pressure at 100% MCR is 9.8 inches water gage with the existing fuel oil burners.

2.2.3 Maximum flue gas temperature at the air heater outlet is 470^0F.

2.2.4 Burners shall fit in place of the existing oil burners with minimum windbox modifications and no pressure part modifications.

2.2.5 Burners shall be started and stopped remotely.

2.2.6 Igniters

2.2.6.1 Igniters shall be natural gas, not spark.

2.2.6.2 Intermittent igniters are preferred.

2.2.6.3 Scanners shall be used to prove igniter flames.

2.2.7 Shop assembled valve racks with interconnecting piping shall be furnished.

2.2.7.1 Connections to each burner valve train shall be: gas inlet, gas out to burner, gas out to igniter, vent out.

2.2.7.2 The valve train for each burner shall contain safety valves, vent valves and control valves along with provisions for necessary instrumentation.

2.2.7.3 Two valve racks shall each contain two burners' valves with one burner valve train above the other train. These two racks shall be opposite hand.

2.2.7.4 Valve train shall include provisions for automated leak checking.

2.2.7.5 Each valve rack shall fit within these dimensions: 8' long, 2 ½' deep, 6' high.

2.2.8 Flex hoses shall be selected for a boiler movement shown on the included B&W drawings.

2.2.9 The flue gas recirculation (FGR) fan shall be direct driven. Its test block margins on capacity and pressure shall be large enough to ensure that the fans will meet their net conditions when installed.

2.2.9.1 Sleeve bearings and antifriction bearings are acceptable.

2.2.9.2 The first critical speed shall be 125% of the operating speed.

2.2.9.3 Fans with 3,600 rpm are not allowed

2.2.9.4 Fans with 1,800 rpm are permissible with drivers of 125 horsepower and less. Fans with drivers larger than 125 horsepower shall have a maximum speed of 1,200 rpm.

2.2.9.5 Fans shall have its rotor supported between the bearings (Arrangement 3). Independent bearing pedestal supports shall be provided with separate sole plates which may be permanently mounted in place.

2.2.9.6 Material handling fans shall have radial bladed wheels with stiffeners and sufficient strength to resist an unbalanced condition of the rotor caused by wear on the blades. Renewable blade, scroll, and side plate liners of 350 Brinell minimum abrasion resistant materials shall be furnished.

2.2.9.7 Fans shall be furnished with motor, coupling and approved coupling guard, installed and aligned when possible. 200 HP and larger motors shall be 4160 v. Smaller motors shall be 480 v.

2.2.10 FGR system design

2.2.10.1 FGR ductwork shall have a minimum wall thickness of 0.100". Round ductwork is preferred.

2.2.10.2 Nonmetallic expansion joints with material selected for the maximum flue gas temperature shall be used.

2.2.10.3 Control dampers shall be designed for the maximum flue gas temperature. Air cooled damper bearings are preferred.

2.2.11 All seller–furnished natural gas piping shall be painted yellow.

PART 3 – EXECUTION

3.1. FURNISHED BY BUYER

3.1.1. Burner management system

3.1.2. Scanner cooling air supply

3.1.3. Installation

3.1.4. Wiring

3.1.5. Piping

3.1.6. Startup

APPENDIX A

OWNER TECHNICAL DATA SHEET

Equipment Identification:

Equipment Name: Low NOx Natural Gas Burners

Project Number: TBD

GP Equipment Number: TBD

Mill Location: Palatka, Florida

Process Conditions: Per Section 2.1 Design Criteria

Equipment Requirements: Per Section 2.2 Materials & Construction

Paint Color: Seller's Standard

Comments:

APPENDIX B

SELLER TECHNICAL DATA SHEET

All blanks in this Data Sheet must be filled in by the Seller. The completed form shall be submitted by the Seller with the equipment quote.

General Equipment Information

Seller: ____________________

Equipment Identification: ____________________

Georgia Pacific Project Number: ____________________

Georgia Pacific Equip Name & Number: ____________________

Georgia Pacific Millsite: ____________________

Drive Requirements: ____________________

Seal Water Requirements: ____________________

Lubrication Requirements: ____________________

Design Weights (Approximate, Pounds: ____________________

Shipping Weight (Incl Approx Wt Of Crate, Pounds: ____________________

Manufacturing / Assembly Location: ____________________

Quote Options: ____________________

Equipment Components: ____________________

APPENDIX C

COMMERCIAL OPTIONS

This form must be filled out by the Seller and be submitted with all quotes.

Seller: ______________________________

Proposal Identification: ______________________________

Georgia Pacific Project Number: ______________________________

Georgia Pacific Equip Name & Number: ______________________________

Georgia Pacific Millsite: ______________________________

Base Pricing Quotes:

Equipment Proposal ______________________________

Shipping Weight of all Materials ______________________________

Freight Cost FOB Mill Site ______________________________

Delivery Time (After PO) ______________________________

Optional Costs:

Spare Parts Listing ______________________________

Misc. Special Tools ______________________________

Terms ______________________________

APPENDIX D
PERFORMANCE AND OPERATIONAL GUARANTEE

The Seller guarantees that Process Conditions and Performance Measures called out in Appendix A shall be met. Also, the Seller guarantees the following:

- Guarantee the specified heat input based on the specified natural gas.
- Guarantee the specified emissions rates over the specified operating range.
- Predict and guarantee the excess air required in terms of percent oxygen, dry volumetric basis, measured at the generating bank outlet.
- Predict and guarantee the air leakage through idle burners in terms of O_2 in flue gas at 33% load with two burners operating and the remaining burners idle.
- If FGR is required, predict and guarantee NOx emissions without FGR in operation.
- Predict and guarantee the required windbox pressure ant 100% MCR.

PERFORMANCE WARRANTY

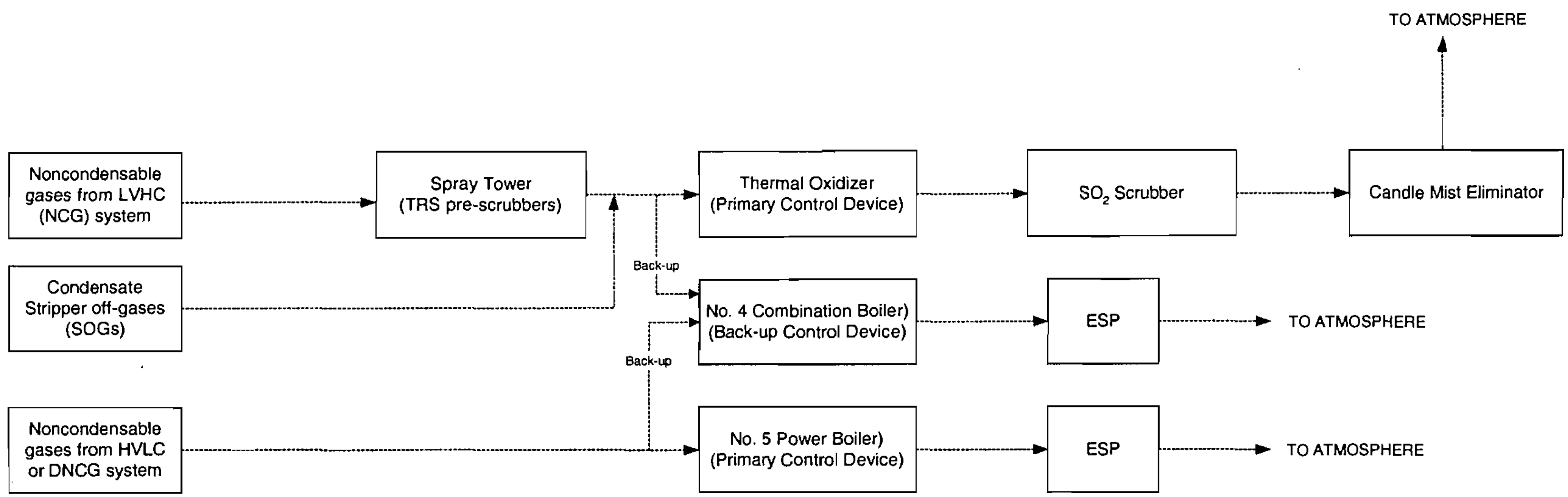
Warranties: The seller shall guarantee performance of the equipment in this specification. The seller shall have mechanical defects warranty for a period of 12 months from startup or 18 months after shipment, whichever occurs first.

In addition, Seller must demonstrate that the Equipment meets each element of the following Performance Warranty.

TESTING PROCEDURES

- Performance testing will be witnessed by the OWNER or by an OWNER appointed representative.
- Performance testing schedules will be approved by the OWNER.
- The SELLER will provide all testing documentation to the OWNER.
- If any test is unsuccessful, it will be repeated following evaluation and adjustments made as necessary on the Equipment. If still unsuccessful, SELLER to promptly and immediately correct any faults with all necessary steps that are needed, including manufacture or purchase of parts locally for delivery to mill site if deemed necessary.
- No third party will be present, nor given access to any test data without the written consent of the OWNER.
- The costs and expenses of SELLER'S personnel involved shall be borne by the SELLER.

FIGURE 1
SIMPLIFIED PROCESS FLOW DIAGRAM FOR LVHC AND HVLC EXHAUST GASES



Note: Examples of low volume high concentration (LVHC) gases include emissions from digesters, evaporators, and concentrators

Note: Examples of high volume low concentration (HVLC) gases, also referred to as dilute non-condensable gases (DNCGs), include emissions from brown stock washers, pressure knotters, bleach plant pre-washer, oxygen delignification system, softwood and hardwood high density storage tanks.

TABLE 1-1
CONTEMPORANEOUS AND DEBOTTLENECKING EMISSIONS ANALYSIS AND PSD APPLICABILITY INCORPORATION OF NO. 5 POWER BOILER FIRING 100% NATURAL GAS

Source	Pollutant Emission Rate (TPY)										
Description	SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluoride
Future Potential Emissions											
No. 4 Combination Boiler - 2.35% S [a]	835.5	496.5	1,010.5	80.8	59.8	34.4	---	36.8	0.097	0.0071	0.095
No. 5 Power Boiler firing 100% natural gas [h]	1.5	311.5	209.3	18.9	18.9	13.7	---	0.0	1.25E-03	6.48E-04	0
No. 4 Lime Kiln: annual: 20 ppmvd TRS	40.0	297.4	71.5	130.2	128.0	41.4	25.1	1.8	0.25	--	--
No. 4 Recovery Boiler [c]	153.9	738.1	2,245.6	331.1	248.3	92.0	34.2	15.9	0.014	8.3E-05	--
No. 4 Smelt Dissolving Tank [d]	33.7	69.6	11.4	55.2	49.7	115.0	14.9	--	0.013	8.3E-05	--
Black Liquor/Green Liquor Tanks [d]	--	--	--	--	--	14.0	3.7	--	--	--	--
Caustic Area [d]	--	--	--	2.6	2.6	18.9	5.8	--	--	--	--
Other Projects [g]											
Bark Handling System	--	--	--	22.8	13.9	475.8	--	--	--	--	--
Total- Future Potential	**1,064.6**	**1,913.1**	**3,548.3**	**641.7**	**521.3**	**805.2**	**83.7**	**54.5**	**0.38**	**0.0079**	**0.095**
Past Actual Emissions [f]											
No. 5 Power Boiler (2004-2005 data) [h]	3,316.4	459.6	48.9	193.6	166.5	2.7	---	145.9	0.015	0.0011	0.365
No. 4 Combination Boiler [b]	820.4	413.2	780.3	99.2	71.9	22.4	--	36.1	0.065	0.0047	0.084
No. 4 Lime Kiln	0.04	101.4	6.8	51.3	50.4	2.5	2.6	0.0018	0.16	--	--
Bark Handling System	--	--	--	14.6	10.6	175.4	--	--	--	--	--
No. 4 Recovery Boiler	14.7	473.2	1,249.3	134.7	101.0	9.5	11.3	1.50	0.012	6.8E-05	--
No. 4 Smelt Dissolving Tank [d]	27.7	57.1	9.4	34.9	31.4	94.4	5.1	--	0.010	6.8E-05	--
Black Liquor/Green Liquor Tanks [d]	--	--	--	--	--	9.7	3.0	--	--	--	--
Caustic Area [d]	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Total- Past Actual	**4,179.2**	**1,504.5**	**2,094.7**	**530.0**	**433.5**	**329.2**	**26.0**	**183.5**	**0.26**	**0.0059**	**0.449**
Increase Due to Project	**-3,114.6**	**408.6**	**1,453.7**	**111.7**	**87.7**	**476.0**	**57.7**	**-129.1**	**0.11**	**0.0020**	**-0.354**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0.6	0.1	3.0
Netting Triggered?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No
CONTEMPORANEOUS EMISSION CHANGES											
MACT I Compliance Project (9/00) (Permit nos. 1070005-007-AC and -017-AC) - startup 2002											
--Increase Due to New Thermal Oxidizer	109.7	151.4	8.8	30.7	30.7	9.1	0.89	7.7	--	--	--

Georgia-Pacific

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

January 31, 2007

RECEIVED
FEB 05 2007
BUREAU OF AIR REGULATION

Mr. Jeffery F. Koerner
Air Permitting North Section
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32299-2400

Re: Modification of the No. 4 Recovery Boiler, No. 4 Lime Kiln and No. 4 Combination Boiler

Project No. 1070005-038-AC/PSD-FL-380
Response to Request for Additional Information

Dear Mr. Koerner:

We are in receipt of your request for additional information, dated December 15, 2006, regarding our permit application to modify the No. 4 Recovery Boiler, No. 4 Lime Kiln and No. 4 Combination Boiler.

As noted in your question #7; Georgia-Pacific is requesting that the Department separate the projects into two separate PSD applications for the purposes of review and permit issuance due to the critical timing associated with the projects for the Recovery Boiler and Lime Kiln. Separate permits would be issued as suggested for the No. 4 Recovery Boiler and No. 4 Lime Kiln as one project, and for the No. 4 Combination Boiler as the second project. Our responses to the questions in your letter are intended to only address issues associated with the No. 4 Recovery Boiler and No. 4 Lime Kiln. A separate response will be forthcoming address the issues associated with the No. 4 Combination Boiler. For ease of following GP's responses, we have repeated the FDEP's questions prior to the answers.

1. **The project is significant for sulfuric acid mist emissions and requires a BACT determination. SAM emissions from the No. 4 Lime Kiln result from firing residual oil; however, overall emissions are very low (estimated < 2 tons/year) due to the natural scrubbing action of the lime kiln and possible additional reductions in the venturi scrubber. For the No. 4 Combination Boiler, the control technology review indicates the following technologies are available for the control for SAM emissions: dry ESPs, wet**

ESPs, and wet scrubbers. Your control technology review for the No. 4 Recovery Boiler also indicates mist eliminators in addition to this equipment. Dry ESPs, wet ESPs, wet scrubbers were eliminated from consideration due to expected high capital costs. Mist eliminators were eliminated from consideration because no actual installations were identified that reduced SAM emissions with mist eliminators on a recovery boiler. However, this technology appears transferable. Please provide a cost effectiveness analysis for adding mist eliminators to the No. 4 Recovery Boiler and the No. 4 Combination Boiler.

As stated in the application for the No. 4 Recovery Boiler, reducing SO_2 emissions will also result in lower SAM emissions. For this reason, the Department will consider reducing the fuel sulfur content of the residual oil in making its BACT determination. Please provide a control technology review for lowering the fuel sulfur content of the residual oil currently being fired to include a cost effectiveness analysis.

Alternatively, provide a combination of fuel consumption/fuel sulfur limits that maintain the net emissions increases below the PSD significant emissions rate for SAM emissions (7 tons/year). Depending on future use, this may be readily achievable because the primary fuels are BLS for the No. 4 Recovery Boiler and bark/wood for the No. 4 Combination Boiler. In fact, the stated purpose of the modifications to the No. 4 Combination Boiler is to more efficiently combust bark/wood and to displace oil firing.

Answer: GP will address the sulfuric acid emissions (SAM) associated with this project by reducing those emissions below the PSD threshold. The specifics of the reduction strategy are being formulated. A specific plan and updated netting table will be provided to the Department with the response for the #4 Combination Boiler, which we expect to submit within the next few weeks.

2. **On November 30th, we received a graph by facsimile labeled "Recovery Boiler 12 Hr. Startup Curve". The graph plots steam pressure (psi) versus time (hours). A statement following the graph indicates that "..., it is also a normal startup curve that has been doubled to accommodate an extended boiler outage." Please provide the original graph for a normal startup and identify the conditions for a normal startup. Also, please identify the conditions of a startup after an extended outage and explain the rationale for "doubling" the original graph.**

Answer

Georgia-Pacific's permit currently recognizes an 8-hour startup period for the Recovery Furnace. We are specifically requesting a longer startup period to better reflect normal startup procedures for recovery furnaces. We believe the Department has the inherent authority to provide for such necessary startup processes under the Florida rules, including the excess emission rule.[1]

[1] Florida Rule 62-210.700(1) expressly allows excess emissions resulting from SSM conditions provided the source uses best operational practices to minimize emissions and the excess emissions do not exceed two hours, "unless specifically authorized by the Department for longer duration."

As will be demonstrated by this information being provided in this response, a startup period can routinely be more than 24 hours from first fire to the point of removing the oil guns from the furnace. **Georgia-Pacific is requesting a 24-hour startup period for the Recovery Furnace**. The attached charts demonstrate the need for this startup period.

Georgia-Pacific is specifically concerned with startup due to the extended amount of time the recovery furnace is typically on residual fuel (either as the exclusive fuel or as a stabilizing fuel when black liquor is being introduced) during this period. This can result in an extended period during which we are potentially unable to comply with the sulfur dioxide and nitrogen oxide standards that apply during normal (non-SSM) recovery furnace operations. The SO_2 and NO_x emissions of the unit during these times are closer to those of an oil fired boiler than a recovery furnace. This issue is not unique to Palatka – all recovery furnaces use auxiliary fuels during periods of startup/shutdown and/or to stabilize the combustion process during periods of low black liquor burning rates and periods of low solids in the liquor or poor quality liquor.

The sulfur dioxide emissions from the recovery furnace when starting up and shutting down the unit are directly related to the sulfur content of the auxiliary fuels used. Georgia-Pacific requests that compliance with the sulfur dioxide standard during these periods be demonstrated by using fuels that comply with the permitted sulfur content.

Reliance on a start up curve to demonstrate the length of a reasonably-necessary startup period for the recovery furnace is not adequate. The startup curve only demonstrates the time necessary to build pressure / temperature in the steam system and to bring the unit online, thus making steam. The full startup ends when black liquor burning is self-sustaining and oil is removed from the furnace.

Figure 1 contains three startup curves for the recovery furnace. The first is the rapid startup curve typically used for the unit. The second is the startup curve in the DCS which is used during a cold startup. The third is the textbook curve which is based on increasing temperature of the steam by 100 degrees Fahrenheit (°F) per hour to control the tube expansion rate. Controlling the startup temperature of the furnace maximizes the cyclic life of the superheater section of the unit. As you are aware, this furnace currently has issues with steam tube cracking that will be addressed by the implementation of this project.

As you consider the information being presented, please keep in mind that the recovery furnace is not a boiler, but a chemical recovery unit. Its primary function in this capacity is to recover the chemicals from the Kraft pulping process first and then produce steam as a secondary function. Rapidly pushing a recovery furnace through a startup can result in very unsafe conditions.

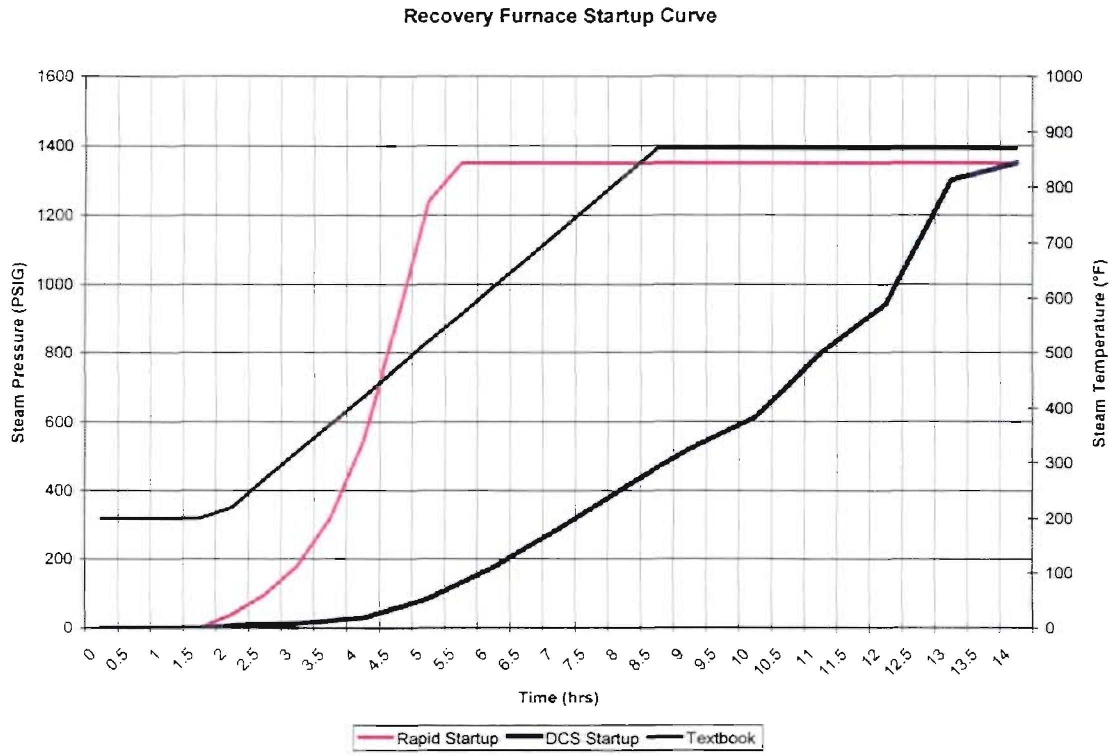


Figure 1. Startup curves for the Kraft Recovery Furnace at Georgia-Pacific, Palatka Operations

As previously noted, the startup curve in Figure 1 does not represent the end of the startup process for the recovery furnace. After the unit is brought on line with oil, we must continue to burn oil along with the black liquor until a minimum sustainable load is reached on black liquor. At that point, the heat available from the black liquor is sufficient to dry and combust the organics. At that time, the oil burners are gradually removed from service. When all the oil is removed, the unit is considered to be fully out of the startup period.

Figures 2 through 5 show graphs that are screen prints of the actual operations data from the Plant Information system during four startup/shutdown periods of the recovery furnace within the past year. These graphs demonstrate the actual startup periods of the recovery furnace which can last much longer than the standard 8-hour period allowed in current Title V permit. The information hand written on the graphs comes from the operator logs during those periods or interpretation of the graphics. It should be noted that black liquor flow is not adequately represented on the graphics because it includes materials recycled through the black liquor feed system.

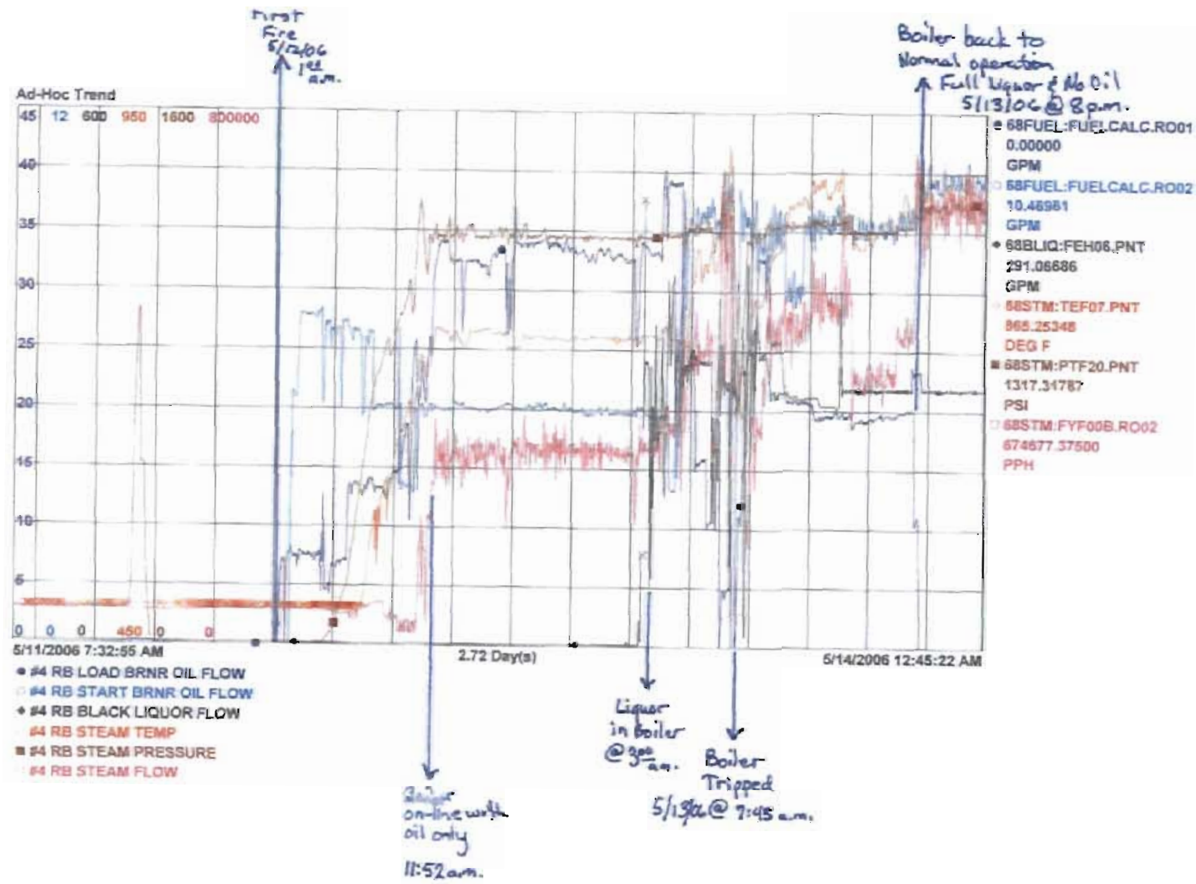


Figure 2. Printout from the May 12, 2006 cold startup of the recovery furnace. The first fire of the furnace on oil occurred at 1:00 a.m. on May 12. The unit went through its startup curve and was online with only oil at 11:52 a.m. The furnace was operated on only oil until 3:00 a.m. on May 13. At that point, black liquor was initially fired in the unit. At 7:45 a.m. on May 13, the furnace tripped and was immediately restarted. The furnace operated with oil as a supplementary fuel until 8:00 p.m. on May 13. As such, for this scenario, the total startup curve was 43 hours.

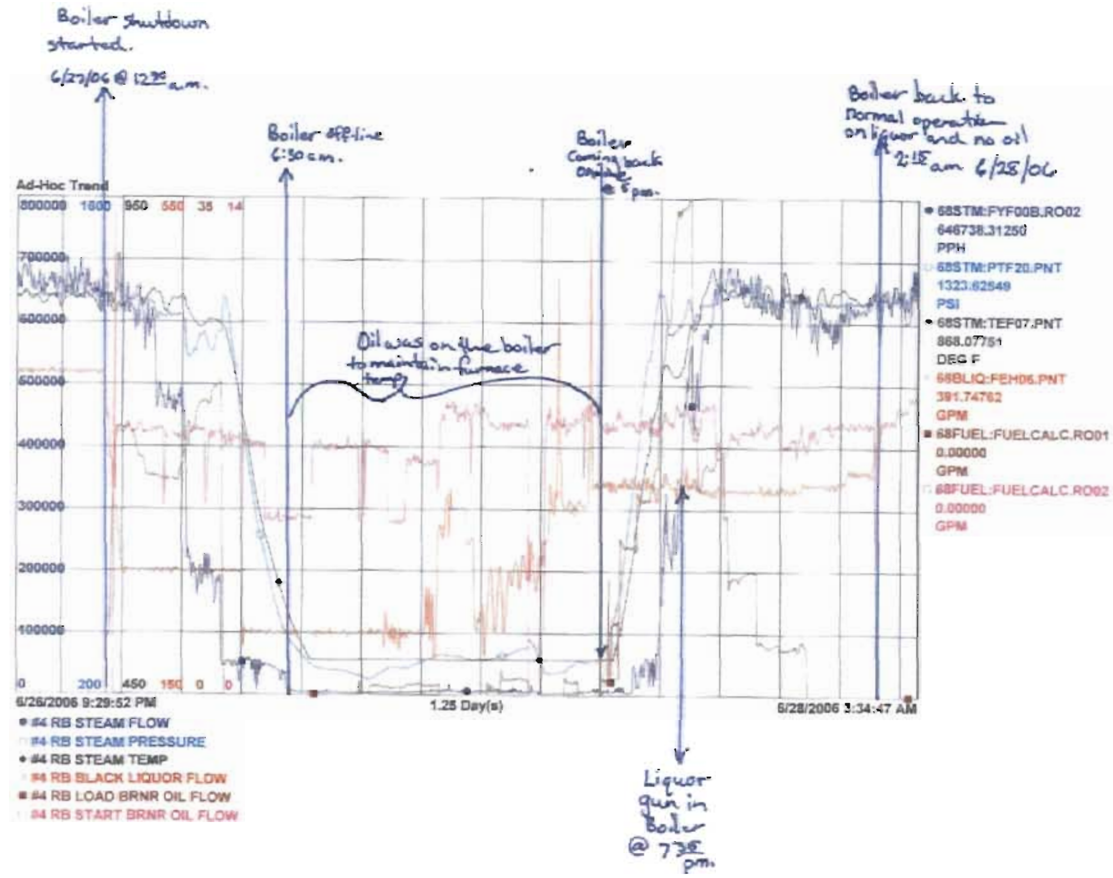


Figure 3. This figure documents the shutdown and startup of the Recovery Furnace on June 27 & 28, 2006. The shutdown process began at 12:30 a.m. on 6/27/06; at that point, oil was put in the Recovery and black liquor was taken out. The smelt bed was burned out and the boiler was offline at 6:30 a.m. on 6/27/06. During the downtime on the unit, a small amount of oil was burned in the furnace to maintain a minimum header pressure and temperature. At 5:00 p.m. on 6/27/06; the oil flow was increased and the process of bringing the furnace back online was started. Black liquor burning was reestablished at 7:55 p.m. and oil was removed from the unit at 2:15 a.m. on 6/28/06.

This review demonstrates a typical practice of burning only oil in the furnace during maintenance outages to allow the furnace to come back online quickly and eliminate a cool down / heat up cycle on the furnace.

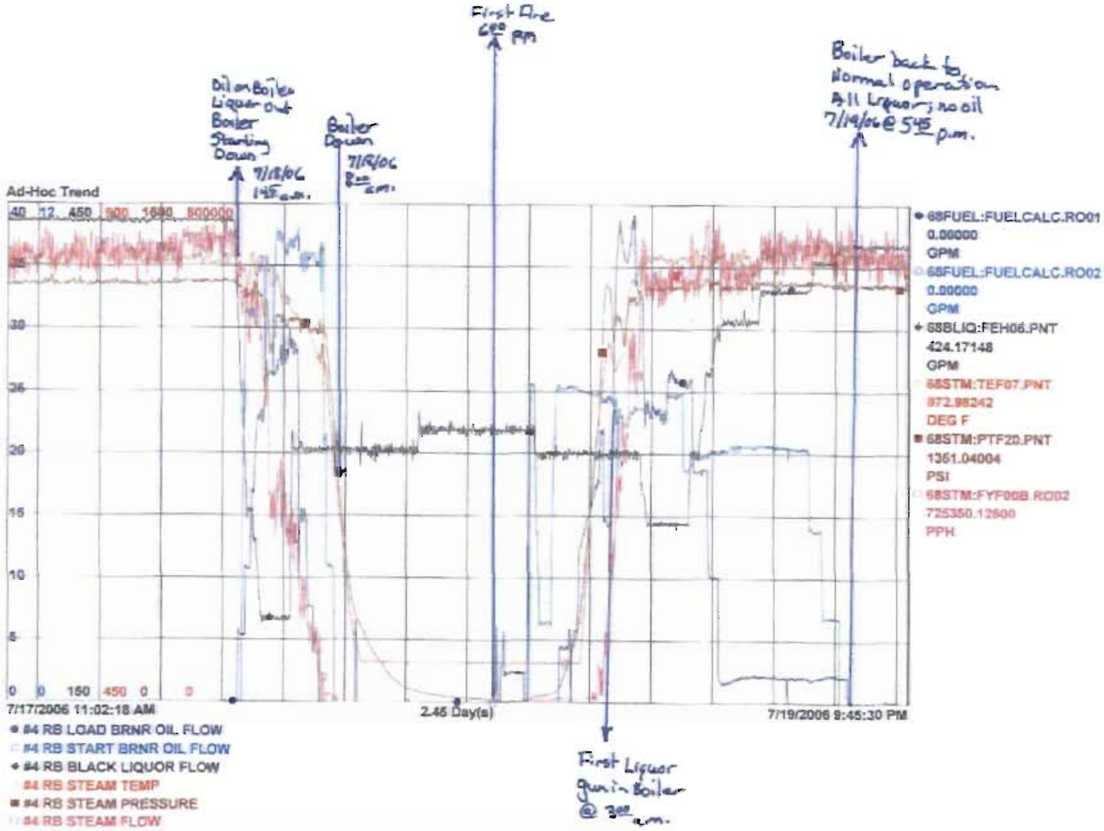


Figure 4. Printout for shutdown/startup of the recovery furnace on July 18-19, 2006. The shutdown process began at 1:45 a.m. on July 18 when oil was placed in the furnace and liquor was pulled. Over the next 6 hours, the smelt bed was burned down and then the unit was taken offline by 8:00 a.m. on July 18. The startup process began at 6:50 p.m. when oil was first fired in the furnace. The unit was brought online and stabilized, with black liquor first introduced to the unit at 3:00 a.m. on July 19. After stabilizing the liquor burning, oil was continuously worked out of the unit and the last oil gun was removed at 5:45 p.m. on July 19. The start-up period lasted approximately 23 hours.

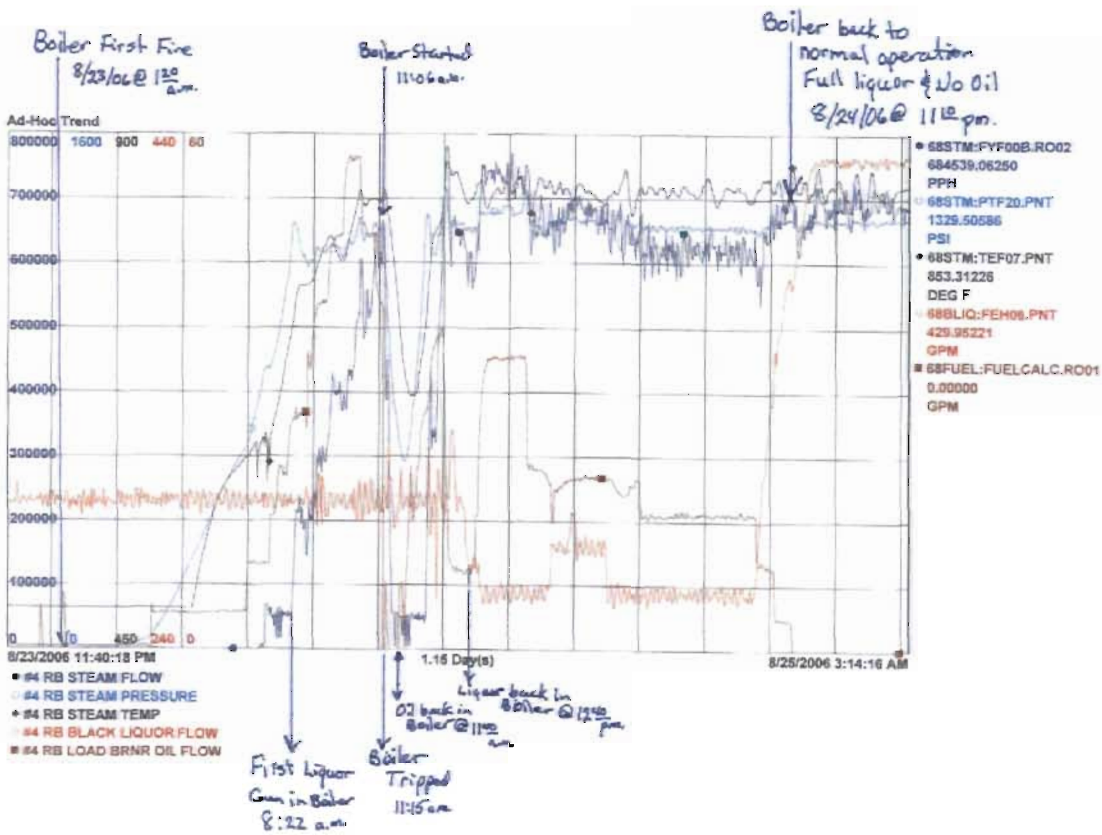


Figure 5. Printout for recovery furnace startup on August 24, 2006. The startup of the unit began with the first fire of oil at 1:30 a.m. on August 24. The first liquor gun was put in the unit at 8:22 a.m. as the furnace was being brought online. As is not unusual, the unit tripped offline at 11:15 a.m. and was brought back online in a rapid fashion on oil, with liquor reintroduced at 12:40 p.m. on August 24. As the unit was stabilized, residual fuel was progressively removed from the furnace and the last oil gun was removed from service at 11:10 p.m. on August 24. The start-up period lasted between 21 and 22 hours.

As is demonstrated by Figures 3 & 4, the shutdown period is generally less than 8 hours. A recovery furnace typically has a shutdown period that is much longer than a typical oil-fired boiler. The shutdown period for the recovery furnace is initiated when oil is put in the unit and black liquor is reduced / removed. The auxiliary fuel, in this case fuel oil, is continually burned in the unit until the smelt bed in the bottom of the furnace is below the smelt spouts. If the smelt bed is not taken below the spouts, the spouts will plug as the furnace cools, causing extensive delays during the startup process.

As previously stated; Georgia-Pacific believes a startup period of 24 hours is justified and should be granted by the Department.

Questions 3 through 5 will be responded to under separate cover as previously discussed in this response

6. **Based on your last submittal, a new ESP will be installed on the No. 5 Power Boiler. No vendor has yet been selected. As you are aware, the No. 5 Power Boiler has been identified as a "BART-eligible" unit. Please ensure that this new control equipment will be designed and selected in accordance with this upcoming regulatory requirement.**

   Answer: Georgia-Pacific is aware that the No. 5 Boiler is a "BART-eligible" unit and we will ensure that the emission controls are consistent with the upcoming regulatory requirements under that program. A tentative BART control submittal will be provided to the Department in the next couple weeks.

7. **The Department is aware of your upcoming spring outage and a stated critical need to implement the modifications for the No. 4 Recovery Boiler and the No. 4 Lime Kiln during this period. The Department believes that this portion of the application is nearly complete. In addition, the Department also believes that the combined netting analysis properly identifies the PSD-significant pollutants for the projects and that the requirements for the air quality analysis have been satisfied. If requested, the Department is now willing to separate the project into two related PSD applications: (1) the No. 4 Recovery Boiler and No. 4 Lime Kiln, and (2) the No. 4 Combination Boiler. Please keep in mind that each related project remains subject to the same PSD-significant pollutants, air quality modeling requirements, etc.**

   Answer: Georgia-Pacific appreciates the Department's understanding of the critical timing issues associated with the upcoming spring outage and vital work that must be completed on these two units. As stated in the opening of this response, Georgia-Pacific is officially requesting that the applications be split as suggested in Question 7.

If you have any questions regarding this response, please contact Michael Curtis at 386-329-0918.

I, the undersigned, am the responsible official of the source for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and the data contained in this document are true, accurate, and complete.

Sincerely,

Keith Wahoske

Keith W. Wahoske, Vice-President
Palatka Operations

cc: W. Galler – GP
T. Champion - GP
T. Wyles - GP
S. Matchett - GP
M. Curtis - GP
B Mitchell
C Holladay
C. Kirts, NED
G. Worley, EPA
J. Bunyak, NPS

Adams, Patty

From: Koerner, Jeff
Sent: Friday, December 15, 2006 4:45 PM
To: Mitchell, Bruce; Adams, Patty
Subject: FW: Project No. 1070005-038-AC/PSD-FL-380, Request for Additional Information

Attachments: 1070005-038-AC - RFI 3.pdf

From: Koerner, Jeff
Sent: Friday, December 15, 2006 4:43 PM
To: 'keith.wahoske@gapac.com'; Michael W. Curtis (Michael.Curtis@gapac.com); David Buff (dave_buff@golder.com)
Cc: Kirts, Christopher; Gregg Worley (worley.gregg@epamail.epa.gov); Dee Morse (dee_morse@nps.gov)
Subject: Project No. 1070005-038-AC/PSD-FL-380, Request for Additional Information

Georgia-Pacific Corporation
Modification of the No. 4 Recovery Boiler, No. 4 Lime Kiln and No. 4 Combination Boiler

Gentlemen:

As we discussed earlier this week, I am providing the attached request for additional information. Please contact me if you have any questions.

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you.

Jeff Koerner, Air Permitting North
Bureau of Air Regulation
Florida Department of Environmental Protection
850/921-9536

1070005-038-AC - RFI 3.pdf (73...

Department of
Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

December 15, 2006

{Sent by Electronic Mail - Return Receipt Requested}

Mr. Keith Wahoske, Vice President of Palatka Operations
Georgia-Pacific, Palatka Mill
P.O. Box 919
Palatka, Florida 32178-0919

Re: Modification of the No. 4 Recovery Boiler, No. 4 Lime Kiln and No. 4 Combination Boiler
Project No. 1070005-038-AC/PSD-FL-380

Dear Mr. Wahoske:

On November 16th, the Department received your response to our request for additional information regarding this project. In addition, we received related facsimiles on November 22nd (regarding the No. 4 Combination Boiler and the No. 5 Power Boiler) and on November 30th (regarding the No. 4 Recovery Boiler). Based on our review of this information, the application remains incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the items below require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

Sulfuric Acid Mist (SAM) Emissions

1. The project is significant for sulfuric acid mist emissions and requires a BACT determination. SAM emissions from the No. 4 Lime Kiln result from firing residual oil; however, overall emissions are very low (estimated < 2 tons/year) due to the natural scrubbing action of the lime kiln and possible additional reductions in the venturi scrubber. For the No. 4 Combination Boiler, the control technology review indicates the following technologies are available for the control for SAM emissions: dry ESPs, wet ESPs, and wet scrubbers. Your control technology review for the No. 4 Recovery Boiler also indicates mist eliminators in addition to this equipment. Dry ESPs, wet ESPs, wet scrubbers were eliminated from consideration due to expected high capital costs. Mist eliminators were eliminated from consideration because no actual installations were identified that reduced SAM emissions with mist eliminators on a recovery boiler. However, this technology appears transferable. Please provide a cost effectiveness analysis for adding mist eliminators to the No. 4 Recovery Boiler and the No. 4 Combination Boiler.

   As stated in the application for the No. 4 Recovery Boiler, reducing SO_2 emissions will also result in lower SAM emissions. For this reason, the Department will consider reducing the fuel sulfur content of the residual oil in making its BACT determination. Please provide a control technology review for lowering the fuel sulfur content of the residual oil currently being fired to include a cost effectiveness analysis.

   Alternatively, provide a combination of fuel consumption/fuel sulfur limits that maintain the net emissions increases below the PSD significant emissions rate for SAM emissions (7 tons/year). Depending on future use, this may be readily achievable because the primary fuels are BLS for the No. 4 Recovery Boiler and bark/wood for the No. 4 Combination Boiler. In fact, the stated purpose of the modifications to the No. 4 Combination Boiler is to more efficiently combust bark/wood and to displace oil firing.

No. 4 Recovery Boiler

2. On November 30th, we received a graph by facsimile labeled "Recovery Boiler 12 Hr. Startup Curve". The graph plots steam pressure (psi) versus time (hours). A statement following the graph indicates that ".... it is also a normal startup curve that has been doubled to accommodate an extended boiler outage." Please provide the original graph for a

normal startup and identify the conditions for a normal startup. Also, please identify the conditions of a startup after an extended outage and explain the rationale for "doubling" the original graph.

No. 4 Combination Boiler

3. Prior to our previous request for additional information, representatives from the Bureau of Air Regulation met with representatives from Georgia-Pacific on October 26th. At the meeting, Georgia-Pacific indicated plans to revise the application to show that the modifications to the No. 4 Combination Boiler would not result in any emissions increases over baseline emissions except for CO emissions. Your response did not include such a revision. Please verify that you no longer have such plans to revise the application.

4. Your first response to our request for additional information (Item #14) identified the design flow as 230,000 acfm. Item #15 of that response also identified corrected flow rate as 135,400 dscfm @ 10% O_2, which was used to calculate the TRS emissions (page 7 of 7 of the application, "Total Reduced Sulfur, Potential Emissions"). Your second response to our request for additional information (Item #3) identifies the preliminary design flow rate as 317,000 acfm. It appears that the flow rate has changed. Please verify design flow rate from the No. 4 Combination Boiler in "acfm" and the corresponding flow rate in "dscfm @ 10% O_2". As necessary, recalculate the potential TRS mass emissions rates and update the applicable application pages.

5. Based on your submittals, the Department believes several of the identified NOx control options are likely cost effective including: selective non-catalytic reduction (SNCR), the Ecotube system with urea injection, and flue gas recirculation (FGR). These controls have been successfully installed on similar units. The Department's review focused on the SNCR system, which has been successfully installed and operated on several units in Florida including RDF boilers, wood-fired boilers, and bagasse-fired boilers. However, both the Ecotube with urea injection and flue gas recirculation (FGR) may also be able to provide similar reductions with comparable costs.

   SNCR: The preliminary SNCR design was based on the co-firing of residual oil with a maximum fuel sulfur content of 2.5% by weight. When the fuel sulfur content is above approximately 1.5% by weight, the vendor indicates that a critical design constraint is to substantially limit the ammonia slip to prevent the formation of ammonium bisulfates, which can foul boiler heat transfer surfaces. With regard to the SNCR design, this will likely result in more injectors, additional injector levels, restricted urea injection rates, and reduced control efficiencies. Although the vendor indicated a reduction of 35% in the bid for the primary fuel scenario (bark/oil), the cost effectiveness estimate was based upon only 30% reduction. Existing biomass-fired boilers are achieving control efficiencies of up to 50% reduction. Will the No. 4 Combination Boiler fire bark/wood alone without other fuels? Please provide a vendor quote on equipment and installation costs for an SNCR system firing bark/wood alone and firing bark/wood with oil having a maximum fuel sulfur content of less than 1.0%. Please include the input criteria for the bid, the expected control efficiencies, and the urea injection rate.

   Ecotube Plus Urea Injection: The estimated cost effectiveness for this system is actually lower than that estimated for SNCR. In addition, the vendor indicates co-benefits for reducing CO emissions, which is also subject to a BACT determination for this project. Please provide the vendor quote used for the Ecotube system with/without urea injection including the input criteria, estimated installation costs, control efficiencies, and urea injection rate.

   FGR: When combined with air staging, flue gas recirculation (FGR) has achieved control efficiencies approaching 50% reduction for similar units depending on initial uncontrolled NOx emissions rates. Please provide the vendor quote for the FGR system including the input criteria, estimated installation costs, and control efficiency.

   Provide a revised cost effectiveness analysis ($/ton NOx removed) for each of these controls options and identify the most cost effective option.

   The project identifies the following physical modifications to the No. 4 Combination Boiler: modified conveyors; new air swept bark distributors; a new overfire air (OFA) system; new low-NOx burners (LNB); and possibly new baffles to more evenly distribute the underfire air. The primary purpose for these modifications is to improve combustion of the bark/wood fuel and the overall burning rate of this fuel to reduce oil firing. Such changes will affect pollutant emissions, which could affect the design of the control systems. For the selected NOx control option, provide a schedule and comments regarding the following: commencement through completion of the boiler modifications; boiler shakedown; performance and emissions testing after completing the boiler modifications; development and final design of the NOx control system; commencement through completion of installing the NOx control system; initial startup and shakedown after completing the NOx control system; equipment shakedown and tuning; initial compliance testing; and monitor certification.

No. 5 Power Boiler

6. Based on your last submittal, a new ESP will be installed on the No. 5 Power Boiler. No vendor has yet been selected. As you are aware, the No. 5 Power Boiler has been identified as a "BART-eligible" unit. Please ensure that this new control equipment will be designed and selected in accordance with this upcoming regulatory requirement.

Miscellaneous

7. The Department is aware of your upcoming spring outage and a stated critical need to implement the modifications for the No. 4 Recovery Boiler and the No. 4 Lime Kiln during this period. The Department believes that this portion of the application is nearly complete. In addition, the Department also believes that the combined netting analysis properly identifies the PSD-significant pollutants for the projects and that the requirements for the air quality analysis have been satisfied. If requested, the Department is now willing to separate the project into two related PSD applications: (1) the No. 4 Recovery Boiler and No. 4 Lime Kiln, and (2) the No. 4 Combination Boiler. Please keep in mind that each related project remains subject to the same PSD-significant pollutants, air quality modeling requirements, etc.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information. If you have any questions regarding this request, please call Bruce Mitchell at 850/413-9198 or me at 850/921-9536.

Sincerely,

Jeffery J. Koerner

Jeffery F. Koerner, Air Permitting North Section
Bureau of Air Regulation

TLV/jfk/bm

cc: Mr. Keith Wahoske, Georgia-Pacific (keith.wahoske@gapac.com)
Mr. Mike Curtis, Georgia-Pacific (michael.curtis@gapac.com)
Mr. David Buff, Golder Associates Inc. (dave_buff@golder.com)
Mr. Chris Kirts, NED Office (kirts_c@dep.state.fl.us)
Mr. Gregg Worley, U.S. EPA, Region 4 (worley.gregg@epamail.epa.gov)
Mr. Dee Morse, NPS (dee_morse@nps.gov)

Georgia-Pacific

BEST AVAILABLE COPY

Consumer Products Division
P.O. Box 919
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November 14, 2006

RECEIVED

NOV 16 2006

BUREAU OF AIR REGULATION

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

Re: Modification of the No. 4 Recovery Boiler, No. 4 Lime Kiln and No. 4 Combination Boiler
Project No. 1070005-038-AC/PSD-FL-380

Response to Request for Information No. 2

Dear Mr. Koerner:

On October 27th, Georgia-Pacific received your second request for additional information regarding this project. Our responses are below and in the attachments to this letter. For ease of following GP's responses we have repeated the FDEP's questions prior to the answers.

1. **Describe the methods that will be used to monitor the heat input rate to the No. 4 combination boiler for fuel oil firing and for bark/wood firing (i.e., oil flow meter, steam production rate with thermal efficiency, periodic sampling and analysis of bark/wood, record keeping, etc.).**

   Answer: GP monitors the rate, the temperature and the pressure of the steam produced in the No. 4CB. Based on these values we calculate the "heat input necessary" to produce this level of steam (in MMBTU/HR). The #4 Combination Boiler has an efficiency of 66%, so the calculated "Necessary Heat Input" is divided by 0.66 to obtain the "actual total heat input" (in MMBTU/HR). GP measures the usage rate for fuel oil and uses that value to calculate the heat input from oil in MMBTU/HR (the calculation is fuel oil flow in gallons per hour times 0.15 MMBTU / Gallon = MMBTU / HR from oil). The heat input from fuel oil is subtracted from the "actual total heat input" to obtain the "heat input associated with burning bark" (in MMBTU/HR). The "heat input associated with burning bark" value is divided by the heat input value of bark (4750 BTU/LB) to quantify the amount of bark burned (tons/hour).

   A calculation summary is shown in **Attachment A**.

   These calculations are performed automatically by the Powerhouse Process Control Computer System and the instantaneous results are displayed on the Powerhouse control room screen for the operators to monitor and control. During stack testing and for compliance reporting, GP takes the fuel oil and bark usage values from the Powerhouse computer system and, using the heat input values for the fuels as listed above, GP calculates the hourly heat input value for the No. 4CB for each of the required three runs. The values for the three runs are then averaged and the 3-hour average value is used to determine the "allowed rate" (adding 10% if the tests were done at less than 90% of maximum) until the next set of tests is completed.

2. **In Attachment E, the particulate matter removal efficiency for the ESP on the No. 5 power boiler (No. 5PB) is listed as 40-65%. Is this only for particulate matter removal when firing fuel oil? Provide the general specifications for the recently modified ESP for the No. 5 power boiler (i.e., number of fields, T-R sets, acfm, cleaning mechanism, cleaning cycle, etc.)**

   Answer: The No. 5PB precipitator removal efficiency of 40-65% is based on particulate removal when burning fuel oil and with two ESP fields in operation. The general specifications of the No. 5 Power Boiler ESP are shown in **Attachment B**. This attachment also shows the general specifications of the No. 4 Combination Boiler (No. 4CB) precipitator as the ESP's are of similar design. The No. 5 PB ESP is proposed to be part of the future No. 4CB emissions control system and in its upgraded state it will help the No. 4CB achieve the efficiencies shown below in the response to Question. No. 3.

3. **Will the ESP for the No. 5 power boiler be used for the No. 4 combination boiler project? What are the preliminary design parameters for firing bark/wood (inlet loading, outlet loading, removal efficiency etc.)?**

   Answer: Yes, it is GP's intent to use the No. 5PB precipitator for the No. 4 CB and to build a new ESP for the No. 5PB. The preliminary design parameters for the No. 4CB ESP project are as follows: Air Flow = 317,000 acfm, Maximum Temperature = 500 °F, Moisture = 20%, Inlet Loading = 1.4 gr/dscf; Outlet Loading = 0.016 gr/dscf; PM Removal Efficiency = 98.9%.

4. **If a new ESP will be added for the No. 5 power boiler, provide: the general specifications (i.e., number of fields, T-R sets, acfm, cleaning mechanism, cleaning cycle, inlet loading, outlet loading, removal efficiency, etc.) and the pertinent application pages.**

   Answer: A new ESP will be added for the No. 5PB. The specifications will be very similar to those shown in **Attachment B** (i.e. when the No. 4CB / No. 5PB project is completed, there will be three very similar in design ESPs with three fields in each ESP – two of the ESPs will serve the No. 4CB and one ESP will serve the No. 5PB).

   The preliminary design parameters for the No. 5PB ESP are as follows: Air Flow = 250,000 acfm, Maximum Temperature = 500 °F, Moisture = 20%, Inlet Loading = 0.08 gr/dscf; Outlet Loading = 0.02 gr/dscf; PM Removal Efficiency = 75.0% (based on two field operation).

   Pertinent application pages are included in **Attachment C** and this response is sealed by the PE of record, Mr. David Buff. Final design and construction information will be provided to the DEP after installation.

5. **Provide the final configuration for controlling particulate matter from the No. 4 combination boiler. If used, will the existing ESP for the No. 5 power boiler be installed parallel to, or in series with, the existing ESP for the No. 4 combination boiler? Will both existing stacks be used? If not, provide the stack configurations.**

   Answer: It is GP's intent to split the flow from the No. 4CB and direct half of the stack gas flow (about 160,000 acfm) to the existing No. 4CB ESP and about half of the flow to the existing No. 5PB ESP. It should be noted that this flow rate (160,000 acfm) is about 73% of the current gas flow rate to the existing No. 4CB ESP. Current plans call for using the existing stacks to service the existing ESP's and to build a new stack for the new ESP to be installed on the No. 5PB.

6. **Attachment GP-EU1-I1 is the revised process flow diagram, which clearly shows flue gas recirculation for the No. 4 combination boiler. Is flue gas recirculation currently installed on the No. 4 combination boiler? Will flue gas recirculation be installed on the No. 4 combination boiler for this project? What is the design flue gas recirculation rate (%) and the corresponding NOx reduction?**

   Answer: Attachment GP-EU1-I1 represents the flow diagram for the future No. 4 Combination Boiler. It inadvertently indicated that FGR would be used in the future. This is not the case, and the flow diagram has been revised and is included in **Attachment D.** FGR is not currently installed on the boiler. FGR was evaluated for the No. 4 CB, and was ruled out as BACT.

7. **For the similar boilers identified in the response (Camas, Washington and Monticello, Mississippi), provide any available stack test data (CO, NOx, SO_2 and VOC) when firing natural gas with bark/wood and when firing only bark/wood.**

   Answer: The GP mills at Camas and Monticello have provided the following data: **(in lbs/MMBTU).** There is no data for firing "bark only". Note that the Camas Mill mixes its bark with primary solids from its wastewater clarifier and burns the resulting mixture.

	CO	**NOx**	**SO_2**	**VOC**
Camas (gas & bark & solids)	**0.027**	**0.18**	**0.059**	**<0.001**
Camas (bark & solids –some gas)	**0.29**	**0.18**	**0.002**	**0.016**
Monticello (gas & bark)	**0.56**	**0.18**	**0.016**	**0.015**
(Monticello- 24% gas / 76% bark - based on heat input)				
NCASI Factors for bark	**0.6**	**0.22**	**0.025**	**0.017**

   Neither of these facilities burns No. 6 Fuel Oil or NCG/SOG gases in their bark boilers as does the Palatka Mill. It would therefore be inappropriate to compare the Camas / Monticello emission rates with the Palatka emission rates.

8. **Please provide the Fuel Tech guarantee for SNCR as well as Georgia-Pacific's request for bid on an SNCR system.**

   Answer: This information is provided at **Attachment E.**

9. **You provided an additional SO_2 modeling analysis for No. 4 recovery boiler during startup. Provide the rationale for this modeling analysis. Also, verify the hourly emissions rates used in the modeling analyses. It appears that the original "109.9 lb/hour" was used in the analysis of the 24-hour average.**

   Answer: - The purpose of the SO_2 modeling analysis for the No. 4 RB during startup was to demonstrate that the Florida AAQS for $SO_2$2 would not be exceeded during startup conditions for the Boiler. The underlying reason for the modeling was to obtain higher permitted emission limits for SO_2 during startup, since the draft permit for the No. 4 RB had imposed SO_2 emission limits during startup which were reflective of normal operation of the boiler. Since fuel oil usage and SO_2 emissions will be higher during such periods, and flue gas flow rates and temperatures lower than normal operation, a concern existed that startup emissions could pose an AAQS problem. However, the modeling analysis demonstrated that RB start up impacts were within the AAQS.

Regarding the SO_2 AAQS modeling analysis for normal operation of the No. 4 RB, we concur that the 24-hour averaging time modeling incorrectly used an SO_2 emission rate of 109.9 lb/hr. The correct emission rate should have been 292.8 lb/hr (100 ppmvd), as shown in Attachment I, Table I-1 of the September letter. The revised modeling has been completed, and the results are provided in revised Table I-4 which is included in **Attachment F.**

GP modeled start up SO_2 emissions based on fuel oil flow rates of 80 gpm (3 hour) and 40 gpm (24 hour) that would equate to stack SO_2 emissions in the range of 300 to 600 ppmvd at 8% O_2. Based upon the results of the modeling, Georgia-Pacific believes that the Department should approve different SO_2 limits for the Recovery Boiler when the boiler is burning: (1) Black Liquor and Black Liquor/fuel oil and (2) when the boiler is burning only fuel oil. For Scenario No. 1 the applicable limit would be 100 ppmvd SO_2 at 8% O_2 as a 24 hour rolling average. However, for Scenario No. 2 the compliance limit would be that GP burn fuel oil containing sulfur at less than or equal to 2.35% and that the RB not exceed the 10% capacity factor limit for burning fossil fuel.

Note that GP would still agree to meet the 12.0 ppmvd at 8% O_2 12-month rolling average limit for SO_2 emissions from the Recovery Boiler.

10. **In Attachment I, see Table I-6 titled, "SO_2 Class I Impacts in the Okefenokee". The 24-hour second highest values in the table do not match the modeling results submitted. Modeling results (2001) show a 24-hour second highest value of 4.14 ug/m^3 at receptor 5 instead of 3.99 ug/m^3 at receptor 15. Also, modeling results (2003) show a 24-hour second highest value of 2.25 ug/m^3 at receptor 30, instead of 2.16 ug/m^3 at receptor 43. Verify the information and correct as necessary.**

    Answer: Table I-6 has been revised to match the modeling results and the revised table is included in **Attachment G.**

11. **In Question No. 1 of RAI-#1** the Department asked for test data documentation for the 60% removal efficiency values that GP uses for the NCG prescrubbers. At the time we answered the request, GP could not locate any efficiency data regarding these scrubbers. However, such data was located and is included in **Attachment H.** The data shows that at a 100 gpm scrubber flow, the removal efficiency of TRS in both the Batch and Continuous Prescrubbers is about 65%.

12. The start up time for the #4 Recovery Boiler can range from 8 to 16 hours based upon whether it is coming out of a cold outage or a "warm off-line" event. GP requests the department to approve a start up / excess emissions time period of 12 hours for the #4RB.

As needed, application updates and information are included in the attachments as indicated throughout this response report. If you have any questions regarding this response, please contact Michael Curtis at 386-329-0918.

I, the undersigned, am the responsible official of the source for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and the data contained in this document are true, accurate, and complete.

Sincerely,
Keith Wahoske

Keith W. Wahoske, Vice-President
Palatka Operations

cc: David Buff, P.E., Golder
T. Champion, T. Wyles, S. Matchett, M. Curtis - GP
Mr. Christopher Kirts, P.E. - FLDEP

LIST OF ATTACHMENTS

ATTACHMENT A (Q-1)
Calculation sheet – bark burning in No. 4CB

ATTACHMENT B (Q- 2 & 4)
General Specifications – ESP's – No. 5PB and No. 4CB

ATTACHMENT C (Q-4)
Application pages – No. 5PB ESP; PE Seal Form – Mr. David Buff

ATTACHMENT D (Q-6)
Revised process Flow Diagram – GP-EU1 – I1

ATTACHMENT E (Q-8)
Fuel Tech RFP and Fuel Tech SNCR proposal

ATTACHMENT F (Q-9)
Revised Table I - 4

ATTACHMENT G (Q-10)
Revised Table I - 6

ATTACHMENT H (Q-11)
Batch and Continuous prescrubber TRS removal efficiency data

ATTACHMENT A (Q-1)

Calculation sheet – bark burning in No. 4CB

Bark Calculation:

$$\text{Steam}\left(\frac{Btu}{day}\right) - \text{Oil}\left(\frac{Btu}{Day}\right) = \text{Bark}\left(\frac{Btu}{day}\right)$$

$$\text{Steam}^{\text{Equiv}}\left(\frac{T}{HR}\right)_{Bark} - \text{Oil}^{\text{Equiv}}\left(T/HR\right)_{Bark} = \text{Bark}\left(T/HR\right)$$

$$\underline{\text{Steam}^{\text{Equiv}}\left(T/HR\right)_{Bark}}$$

$$= \left(\text{Steam Flow } \frac{k\,lb}{HR}\right)\left(\frac{1000\,lb}{1\,k\,lb}\right)\left(\frac{1440\,Btu}{lb_{steam}}\right)\left(\frac{lb_{bark}}{4750\,Btu}\right)\left(\frac{1\,T}{2000\,lb_{Bark}}\right)$$

$$= \left(\text{Steam Flow } \frac{klb}{HR}\right)(0.1516)$$

$$\underline{\text{Oil}^{\text{Equiv}}\left(T/HR\right)_{Bark}}$$

$$= \left(\text{Oil Flow } \frac{klb}{HR}\right)\left(\frac{1000\,lb}{1\,klb}\right)\left(\frac{gal}{7.888\,lb_{oil}}\right)\left(\frac{150{,}000\,Btu}{1\,gal}\right)(0.66)\left(\frac{lb_{Bark}}{4750\,Btu}\right)\left(\frac{1\,T}{2000\,l}\right)$$

$$= \left(\text{Oil Flow } \frac{klb}{HR}\right)(1.322)$$

$$\boxed{\text{Bark}\left(T/HR\right) = \left(\text{Steam Flow } \frac{klb}{HR}\right)(0.1516) - \left(\text{Oil Flow } \frac{klb}{HR}\right)(1.322)}$$

ATTACHMENT B (Q- 2 & 4)

General Specifications – ESP's – No. 5PB and No. 4CB

NO. 4 COMBINATION BOILER & NO. 5 POWER BOILER

PRECIPITATOR SPECIFICATIONS

1.1 The existing Research-Cottrell electrostatic precipitators are two (2) stand alone chambers. They are three (3) fields long in the direction of gas flow. (The chambers are identical except the No. 5PB chamber has an empty inlet field). The precipitators are a single wall design with a penthouse and hopper bottom. Hoppers are "V" shaped, chamber wide and field long. Each hopper has a screw conveyor feeding collected material to a cross conveyor through rotary valves.

1.2 The precipitator operates under positive pressure. The boiler's induced draft fan is located upstream of the precipitator.

1.3 Collecting plates are Research-Cottrell Opzel single sheet plates. Discharge electrodes are rigid mast Research-Cottrell tab scalloped Duratrodes. There are six (6) Duratrodes in the direction of gas flow in each field. Each of the fields has twenty (20) gas passages with twelve (12) inch spacing. The collecting plates are forty-one feet (41′) high by eleven feet two inches (11′ 2″) long in the direction of gas flow.

1.4 The No. 4CB chamber has a total forty nine (49) rappers: twelve (12) collecting plate rappers per field, six (6) leading end and six (6) trailing end, three (3) discharge electrode rappers per field, and two (2) inlet and, two (2) outlet distribution plate rappers. Rappers are top mounted Magnetic Impulse Gravity Impact (MIGI) rappers.

The No. 5PB chamber has thirty four (34) MIGI rappers. It is missing the fifteen (15) rappers on the empty inlet field (this field was installed in October 2006).

1.5 The fields are individually energized by five (5) transformer/rectifier (T/R) sets (six now that the new field was added to the No. 5PB ESP). Each T/R is connected full wave through a single output bushing. The power supply is 480 volts, 60 Hz, 3 Ph.

T/R Set Ratings

Vac	Iac	kV	Idc	kVA
480	84	55	500	38.6

1.6 The discharge electrode support bushings are housed in a heated penthouse.

1.7 Each outlet plenum supports its own stack.

1.8 The precipitator chambers are not covered by a weather enclosure.

1.9 Rapper controls are BHA SQ300 controls. The precipitator controls are linked to the plant distributed control system and can be monitored from the powerhouse control room. The precipitator controls operate independently. Programming changes are done locally at the precipitator control panels located in the precipitator roof motor control center.

ATTACHMENT B - continued

NO. 5 POWER BOILER NEW PRECIPITATOR SPECIFICATIONS

1.10 New Equipment

1.10.1 Install a complete new ESP with three fields for the PB5 precipitator. This will include but not limited to all collecting plates, discharge electrodes, upper and lower high tension frames, rappers, and all associated support and spacing hardware. Lower high tension frames shall be equipped with anti-sway insulators.

1.10.2 Independent T/R set and controls for the new ESP on the No. 5 PB. Controls shall match existing BHA SQ300 controls.

1.10.3 All electrical equipment, components, and wiring down stream of the Purchaser supplied breakers in a Purchaser supplied motor control center for the new T/R set.

1.10.4 New inlet duct and transition sections to incorporate the PB5 ESP and discharge to a new stack.

1.10.5 Thermal insulation with stainless steel lagging for any new or modified duct work. Lagging pattern to match existing lagging.

1.10.6 A modification of the safety interlock system to incorporate the new T/R set.

ATTACHMENT C (Q-4)

Application pages – No. 5PB ESP; PE Seal Form – Mr. David Buff

ATTACHMENT GP-EU1-I3

DETAILED CONTROL EQUIPMENT INFORMATION
NEW ESP FOR NO. 5 POWER BOILER
(preliminary)

The No. 5 Power Boiler will be equipped with a new electrostatic precipitator (ESP) for particulate control. Preliminary design information for the ESP is presented below.

Parameter	Electrostatic Precipitator
Manufacturer	To be determined
No. of Chambers	1
No. of Fields	3
Gas Flowrate (acfm)	250,000
Flue Gas Temperature (oF)- max	500
No. of Transformer/Rectifier Sets	3
Primary Voltage (V,ac)	0-480
Secondary Voltage (kV,dc)	0-55
Primary Current (A,ac)	0-100
Secondary Current (mA,dc)	0-500
Inlet Dust Loading (normal)	0.044 gr/acf; 0.17 lb/MMBtu
Outlet Dust Loading (normal)	0.011 gr/acf; 0.043 lb/MMBtu
Inlet Dust Loading (sootblowing)	0.13 gr/acf; 0.51 lb/MMBtu
Outlet Dust Loading (sootblowing)	0.033 gr/acf; 0.13 lb/MMBtu
Control Efficiency (%)	75% (minimum)

APPLICATION INFORMATION

Professional Engineer Certification

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

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

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

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

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

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

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

David A. Buff
Signature

11/9/06
Date

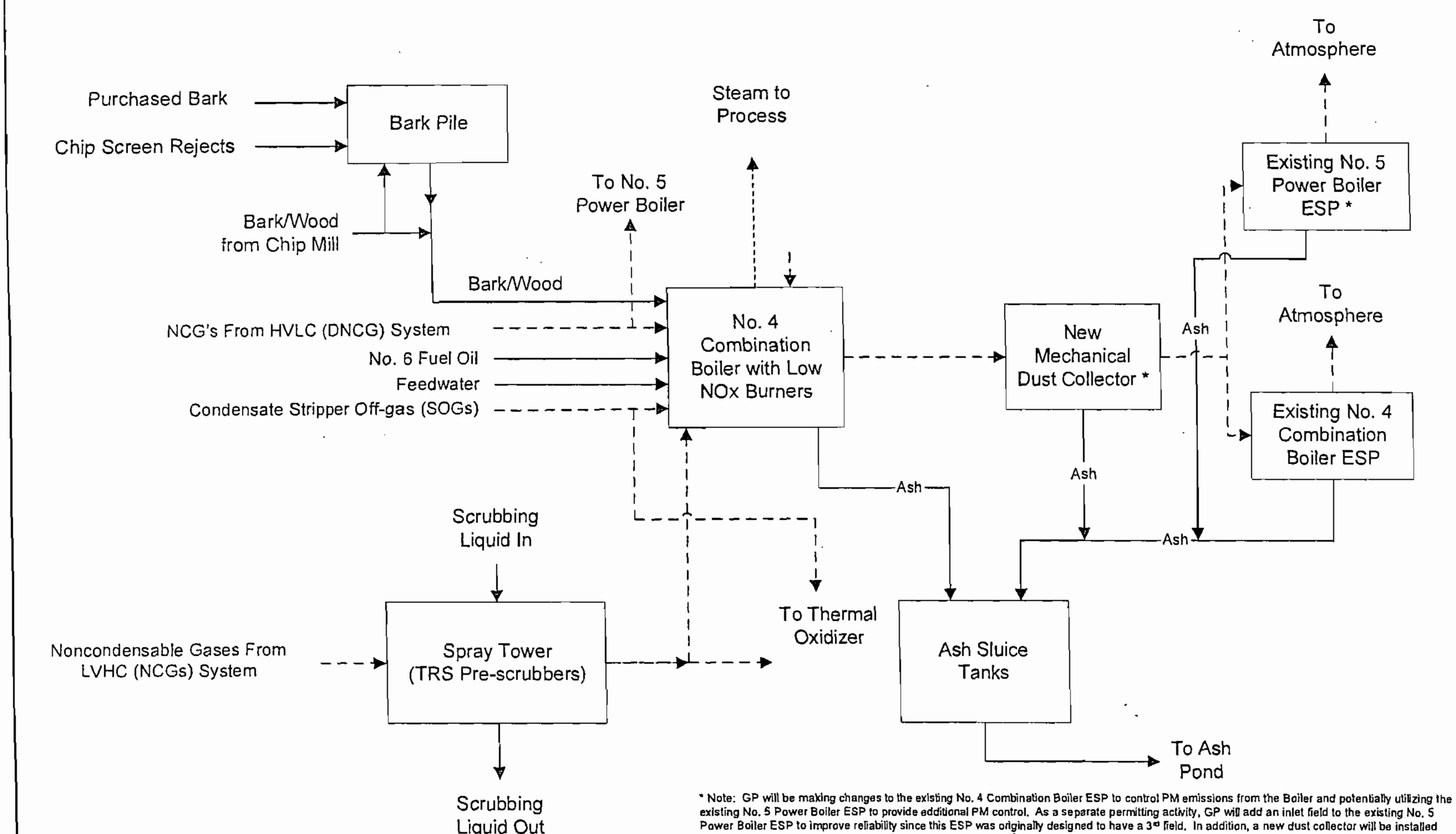
(seal)

* Attach any exception to certification statement.

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

ATTACHMENT D (Q-6)

Revised process Flow Diagram – GP-EU1 – I1



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

Attachment C Process Flow Diagram No. 4 Combination Boiler Georgia-Pacific Palatka Mill	**Process Flow Legend** Solid/Liquid ——→ Gas – – – –→ Steam ---------→	Filename: 4.4 0100/4.1/110706/GP-EU1-I1_rev2.VSD Date: 11/07/06	Golder Associates

ATTACHMENT E (Q-8)

Fuel Tech RFP and Fuel Tech SNCR proposal

Dwg # ~~18B-SHP-268~~
B+W 21879 F-4 6/14/64

FUEL TECH®
Technology for a renewed environment™

Combustion Unit Survey
NOxOUT® SNCR Budgetary Information

Company Name: **Georgia-Pacific Corp**	Date Submitted: **1/12/04**
Customer Reference: **Palatka, FL Mill Combination #4 Boiler**	Date Required: **ASAP**
Location of Facility: **Palatka, FL (40 miles east of Gainesville, FL)**	
Type of Combustion Unit (i.e., Turbine, Boiler, Heater, Incinerator, Furnace, etc.): **Boiler burning bark, clean woodwaste, No. 6 Fuel Oil, natural gas, Non condensable gases**	
~~Furnace Dimensions~~, Cross Sectional x Height or Length (ft), Provide Drawings if Available: **See attached drawings** n'led from Plant 20' x 20' x 45' (to nose arch)	
~~Current Emissions Controls~~ (i.e., LNB, OFA, etc): **ESP for particulate control**	

Primary Fuel:	Secondary Fuel:	Tertiary Fuel:
Bark & Clean woodwaste	**No. 6 Fuel Oil (2.35% S or less)**	**Natural gas**

Heating Value, Primary Fuel (Btu/ lb): 4750 **~~4,500~~ Btu/lb bark/wet woodwaste**	Heating Value, Secondary Fuel (Btu/ lb): oil 18500
Electrical Area Classification other than NEMA4:	Indoor/ Outdoor Installation: Boiler is outdoors
Control Room Interface Required? (Y / N)	Turnkey Quote Required? (Y / N) **Just for SNCR system**
New Unit or Retrofit? Used boiler	Additional Comments:

Please complete the chart below with as much information as possible representing the expected operating conditions.

	Primary Fuel (Bark and Wood)/oil			Secondary Fuel (No. 6 Fuel Oil)		
Maximum Continuous Rating %	100	75	50	100	75	50
Heat Input (mmBtu/ hr)						
Operating Hours @ % Load (hrs)	8,760			8,760		
Gas Temperature @ inlet to superheater (°F)	1,400			---		
Flue Gas Flow Rate lb/hr @ 229 °F leaving economizer				---		
Existing Baseline NOx x☐ #/mmBtu ☐ Dry ☐ Uncorrected ☐ ppm (dry) ☐ Wet ☐ Corrected to Ref O_2						
Desired Target NOx x☐ #/mmBtu ☐ Dry x☐ Uncorrected ☐ ppm (dry) ☐ Wet ☐ Corrected to Ref O_2				---		
Existing O_2 (%, dry)						
Reference or Corrected O_2 (%, dry)						
Moisture Content (%)	30-35 % mixed			---		
Existing CO (~~ppm, in-furnace~~) lb/MM Btu				---		
Existing SO_2 (~~ppm~~) lb/MM Btu						
Existing HCl or Cl_2 (ppm)	---			---		

110 Habersham Drive, Suite 108 Fayetteville, GA 30214-1381
Phone 770-371-5020 Fax 770-371-5021

FUEL TECH®

Technology for a renewed environment™

Proposal No. 04-B-008, Rev 2
NOxOUT® SNCR & NOxOUT Cascade®
NOx Reduction System Options

For

Golder Associates, Inc.
Gainesville, Florida
Project No. 0537627-0200

Georgia-Pacific Corporation
Palatka, FL Mill
No. 4 Combination Fuel Boiler

February 22, 2006

PROPOSAL SUMMARY

In support of efforts underway at Golder Associates and G-P to identify and evaluate post-combustion NOx reduction alternatives for the No. 4 Combination Boiler at the Palatka Mill, Fuel Tech, Inc. (FTI) is pleased to submit our revised budgetary proposal covering the design, supply, fabrication, delivery, personnel training and commissioning of NOxOUT® NOx reduction system options. These NOx reduction options include NOxOUT® SNCR Selective Non-catalytic NOx Reduction and our hybrid SNCR/SCR NOx reduction process, NOxOUT Cascade®.

In our Revision 1 proposal dated January 5, 2006, four (4) SNCR performance cases were presented for the potential combinations of fuel fired in this boiler. As noted in that proposal, NOx reduction via SNCR is limited by a number of factors, such as boiler design, combustion byproducts, upper furnace flue gas temperature, flue gas velocity and residence time available to the SNCR process, furnace access for reagent distribution purposes, sulfur content of the fuel being fired, flue gas temperature at the outlet of the air preheater, and the concentration of ammonia slip that can be tolerated for the specific application. Some of these factors individually affect SNCR NOx reduction performance and others can have a combined influence on the SNCR process – sulfur content and ammonia slip are factors that must be considered in combination when evaluating SNCR performance.

The SNCR performance cases, restated in this Revision, highlight the challenges that the post-combustion conditions present to the SNCR. For this application these challenges, among others, include relatively high CO and the need to control NH3 slip in order to limit the potential formation of ammonium bisulfate (ABS). In order to control ammonia slip, urea must be injected at a higher than ideal temperature – we call this "right side of the slope" injection – which has a direct impact on chemical utilization and NOx reduction performance. The CO present in the flue gas at the point of injection effectively shortens the residence time for the SNCR process reactions, thereby placing an additional restriction on the potential for NOx reduction. If the controlled NOx emissions target is lower than what can be achieved via SNCR or a specific compliance scenario requires lower emissions from this boiler, the SNCR process can be combined with a downstream catalyst to further reduce the NOx emission rate and the ammonia present at the stack.

If the urea reagent is injected at a higher elevation in the furnace (still within the effective temperature window) and the chemical is released at a lower temperature, the SNCR process is operated at a higher point on the process efficiency curve and chemical utilization is greatly improved. Ammonia slip increases when SNCR is operated under these conditions, but the additional slip serves as the reagent for the NOx reduction achieved downstream in the SCR catalyst.

PROPOSAL SUMMARY continued...

Assuming NOx reduction levels of 85-90% are not required, there are other benefits to this approach as compared to a conventional SCR system, including:

- NOx reduction required from the SCR is reduced which relaxes the restrictions on the inlet conditions, such as NH3:NOx distribution, temperature distribution, and flue gas velocity distribution, and
- The treatment length in the catalyst bed (catalyst volume requirements) can be reduced which has an impact on overall pressure drop, catalyst replacement costs, and total weight of the SCR system.

Because the average velocity of the flue gas entering the SCR reactor must be controlled to the level required by the application and the guarantees offered by the catalyst vendor, the cross-sectional area of the duct which houses the SCR reactor is the same for either approach.

Generally speaking, NOx reduction via the NOxOUT Cascade process can be cost-effective when the catalyst can be installed within the confines of the existing ductwork where the cross-sectional area can be expanded to slow the flue gas down to the velocity dictated by the catalyst vendor. When extensive ductwork or structural modifications are required to provide the necessary process conditions, the added cost can be prohibitive.

NOx Reduction Control Options

Depending on the controlled NOx emission rate required for this project, FTI has provided an option for a conventional NOxOUT® SNCR system. By the term "conventional" SNCR we are referring to SNCR that employs multiple levels of wall-mounted injectors. The theory (and practice) behind using multiple levels of injection and a feed-forward/feedback control loop that tracks boiler operation and NOx reduction performance, is that the injector level(s) in-service will change automatically with the boiler load (steam flow) and accompanying shifts in the effective "temperature window" for the SNCR process. For base-loaded operation, the flow of concentrated urea would be biased between these levels or possibly directed to only the upper elevation if this provides the best NOx reduction performance and NH3 slip control.

Some the guidelines for these automatic shifts in injector operation (as a function of steam flow or fuel firing rate) will be defined during the modeling phase of the project and the remainder will be determined at the time of system startup and optimization. Flow rates and atomization pressures for each injector that correspond to specific load and firing conditions are programmed into the PLC or DCS control tables.

PROPOSAL SUMMARY continued...

One way to open up the effective temperature window for a given application is to move injectors up out of the upper furnace and into the convection pass. Standard injectors in the upper furnace produce relatively large droplets of water-encapsulated, atomized urea. The NOxOUT SNCR process relies on the targeted injection and momentum of these droplets to carry the urea, which eventually is converted into gas-phase ammonia, into predetermined areas of the furnace where the NH3 molecules will react selectively with NOx. Relatively speaking, these droplets are large and they require a certain amount of residence time to evaporate before the ammonia is released and they finally come into contact with the ammonia molecules – this is the point in time at which the selective reaction occurs. Any ammonia that leaves the process boundary unreacted will show up downstream as ammonia slip, and because this unreacted ammonia can combine to form undesirable byproducts, this is the limiting factor for the SNCR process.

As our preliminary design for this application indicates, these standard wall injectors can generally achieve a higher level of SNCR NOx reduction if the chemical is released at a lower temperature. For the hybrid system in this particular case, the SNCR NOx reduction would improve nominally from 30-35 percent to as much as 50 percent, and using a downstream catalyst to absorb the increased level of ammonia slip would result in an overall NOx reduction is excess of 70%. The SNCR and Cascade performance details for each firing scenario are included in the Process Design Tables that follow this section of our proposal.

TECHNOLOGY OVERVIEW: NOxOUT® SNCR Process Description

NOxOUT® SNCR is a patented in-furnace, post-combustion NOx reduction technology that relies on the finely controlled distribution of urea to effect a selective reaction of gas-phase ammonia with NOx within a specific temperature region in the upper furnace. The urea is delivered and stored as a 50% aqueous solution that is continuously circulated through the stainless steel SNCR system piping loop. Using plant service water, a metering module located near the injection elevation further dilutes the reagent to a predetermined concentration and precisely controls the flow of diluted reagent to distribution modules located at each injection elevation. The distribution modules provide the final control of diluted reagent and atomizing (plant) air being delivered to each injector, where droplet size and trajectory for each injector have been determined through advanced computer modeling. The final spray characteristics and flow rate of diluted reagent for each injector are fine-tuned during system optimization and startup to correspond to specific boiler operating loads and NOx concentrations.

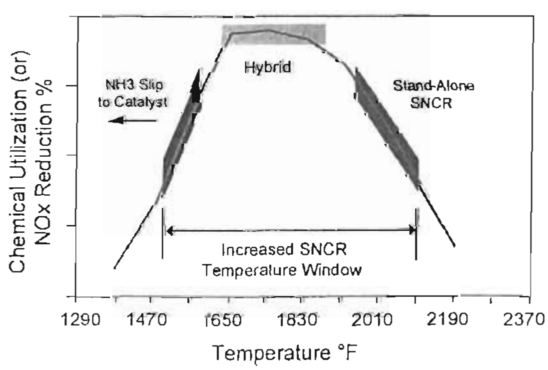
PROPOSAL SUMMARY continued...

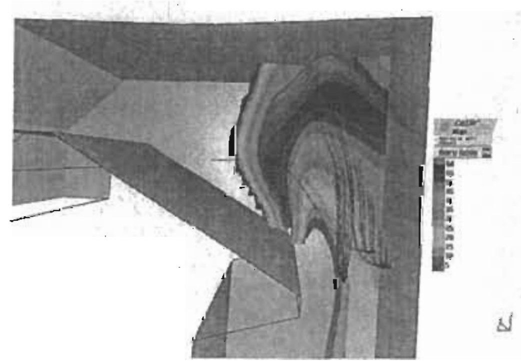
Using feedback NOx emission signals from the CEMS (if available) and these optimized settings, the SNCR system runs in the background under the control of an on-board Allen-Bradley SLC 500 Series PLC (DH+ or Ethernet) and is transparent to the other plant operations. The NOxOUT system information will be available to the operators on a control room computer display or can be tied directly into the plant Distributive Control System if one is available.

TECHNOLOGY OVERVIEW: NOxOUT Cascade® Process Description

Within the NOxOUT Cascade Process are two proven NOx reduction technologies. The first of these is the NOxOUT® SNCR Process which utilizes a stabilized aqueous urea solution that will react with NOx under the appropriate conditions to produce elemental nitrogen, water vapor and trace amounts of carbon dioxide. One of the limiting factors for NOxOUT® SNCR has been the amount of ammonia slip that is allowed to occur. Once the ammonia slip maximum is reached in the system design phase, work towards further NOx reduction must cease if that additional NOx reduction would result in the ammonia slip limit being exceeded. NOxOUT® SNCR has addressed this concern by utilizing what is known as "right side of the slope" injection technology which helps to minimize the amount of ammonia produced while providing significant levels of NOx reduction.

As illustrated by the graph below and the accompanying snapshot from one of our process models, SNCR NOx reduction efficiency and chemical utilization are improved by releasing the chemical at a lower temperature. A controlled, higher concentration of NH3 slip is directed to the SCR catalyst where the ammonia is absorbed and an incremental increase in NOx reduction performance can be achieved. Considerable work indicates that the most cost-effective level for NOxOUT Cascade occurs when the NOxOUT® SNCR component is maximized for NOx reduction.





PROPOSAL SUMMARY continued...

Conventional SCR technology requires the injection of ammonia, either aqueous or anhydrous, into the flue gas prior to the flue gas passing over the surface of a catalyst that is specifically designed to encourage the reduction of NOx. This requires tightly controlled reactor inlet conditions and the maintenance and operation of equipment especially designed to handle and feed the ammonia reagent. The ammonia handling equipment typically consists of a pressure vessel for storage, an evaporator or vaporizer to convert the ammonia to a gaseous phase, a compressor or blower, and an ammonia injection grid. The utility requirements for this equipment generally are high since the evaporator operates at a high temperature and the blower must move very large volumes of gas.

Other related costs with ammonia storage and handling systems include the process safety management and communications requirements established by the Occupational Safety and Health Administration. These regulations require annual reporting of any stored highly hazardous chemicals and annual studies of personal safety and environmental concerns to protect neighboring communities in the event of an accidental release. The NOxOUT Cascade System has incorporated the positive features of the SCR by utilizing a catalyst to further reduce NOx emissions from the NOxOUT® SNCR system but has eliminated all ammonia handling requirements so that the expenses and safety and environmental concerns are removed.

The NOxOUT® SNCR Process for this hybrid system approach is designed to generate a higher, controlled level of ammonia slip from the SNCR process boundary that will become thoroughly mixed in the flue gas. This process-managed ammonia slip then becomes the reducing agent for the reactions that occur in the SCR reactor as the flue gas passes over the catalyst surface. The ammonia that is present will react with the available NOx, further reducing the outlet NOx emissions and the concentration of unreacted ammonia leaving the reactor vessel.

In addition to eliminating the need to store and handle highly hazardous chemicals, the NOxOUT Cascade Process requires a shorter treatment length than would be required by a standalone SCR to achieve the same overall level of NOx reduction. With the NOxOUT Cascade System, a high percentage of NOx is reduced by the NOxOUT® SNCR process, leaving the SCR portion to add only incremental NOx reduction and absorption of the higher level of ammonia slip from the SNCR process. Although the volume of flue gas and the inlet area required for the SCR reactor are the same, the reduced workload on the SCR portion translates into a shorter treatment length and a smaller reactor vessel, lower pressure drop for the system, and fewer constraints on the SCR inlet conditions. In many cases, fan replacements can be avoided along with the costs of a complete system draft analysis. In addition, catalyst replacement costs may be reduced significantly since the volume of catalyst exposed to contaminants in the flue gas is reduced.

PROPOSAL SUMMARY continued...

FTI Scope of Supply

The Fuel Tech Equipment Scope of Supply detailed in this proposal includes:

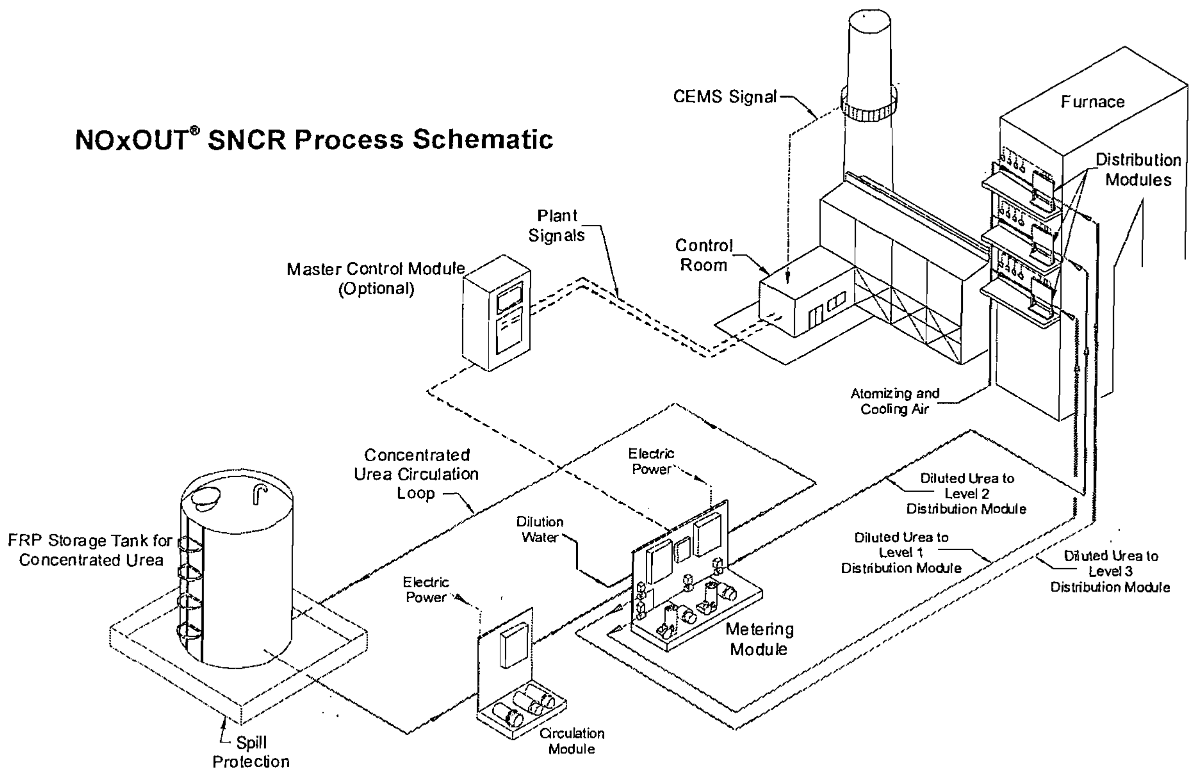
- One (1) double-wall FRP reagent storage tank with all required appurtenances,
- One (1) reagent circulation module to provide a continuous flow of the reagent to the circulation loop piping – the temperature of the concentrated reagent must be maintained at a sufficient level to minimize the potential for crystallization, generally requiring that this loop be heat traced and possibly insulated,
- Multiple-level, Independent Level Control (ILC) Metering module with an on-board water boost pump (WBP) to control the reagent and dilution water flow rates and deliver a consistent urea droplet concentration to the distribution modules and injectors, and
- Distribution modules to provide fine, individual control of the diluted and atomized reagent being delivered into the boiler via the wall-mounted injectors.

Descriptions of the individuals components identified in the FTI Equipment Scope of Supply summaries, including the module descriptions, estimated module weights and dimensions, are provided later in this Proposal. Expected system utility requirements such as dilution water flow rates, atomizing/cooling air flow rates, and electric power consumption also are provided.

PROPOSAL SUMMARY
(Continued...)

The proposed equipment for this project would be configured very closely to what is illustrated below in the SNCR Process Schematic, with the exception that the SNCR system would have only two (2) levels of urea injection.

NOxOUT® SNCR Process Schematic



PROCESS DESIGN TABLE – NOxOUT SNCR

B&W Combination Fuel Boiler No. 4

Design Case		**Bark & Oil**	**Bark, Oil, NCG**	**Bark, Oil, NCG, SOG**	**Oil**
October 2005 Testing		**No. 2**	**No. 5**	**No. 6**	**No. 7**
Furnace Design		Stoker	Stoker	Stoker	Stoker
Maximum Heat Input	(MMBtu/hr)	455.0	438.0	397.0	373.0
Uncontrolled NOx	(lb/MMBtu)	0.240	0.210	0.260	0.280
	(lb/hr)	109.2	92.0	103.2	104.4
SNCR NOx Reduction	(%)	35.0%	30.0%	35.0%	25.0%
Controlled NOx	(lb/MMBtu)	0.156	0.147	0.169	0.210
	(lb/hr)	71.0	64.4	67.1	78.3
NOx Removed	(lb/hr)	38.2	27.6	36.1	26.1
Expected Temperature At Bullnose Elevation	(°F)	1700-1800	1750-1850	1750-1850	1950-2050
Expected NOxOUT® A Consumption @ Load	(gph)	17	15	16	14
Average NH^3 Slip As Measured @ Stack	(ppmvdu)	15	15	15	5
In-furnace CO Limit At Bullnose Elevation	(ppm)	250	250	250	100
Reagent Distribution Strategy	Level 1	6	6	6	6
	Level 2	3	3	3	3

Process Design Comments

* The high sulfur content in the fuel for the oil firing case requires that allowable NH3 slip be reduced to limit the potential formation of ammonium bisulfate, thereby limiting the SNCR NOx reduction that can be achieved.

** The preliminary design calls for retract mechanisms on the six (6) lower (Level 1) injectors. The position of the upper (Level 2) level injectors would be fixed.

PROCESS DESIGN TABLE – NOxOUT CASCADE

B&W Combination Fuel Boiler No. 4

Design Case		Bark & Oil	Bark, Oil, NCG	Bark, Oil, NCG, SOG	Oil
October 2005 Testing		No. 2	No. 5	No. 6	No. 7
Furnace Design		Stoker	Stoker	Stoker	Stoker
Maximum Heat Input	(MMBtu/hr)	455.0	438.0	397.0	373.0
Uncontrolled NOx	(lb/MMBtu)	0.240	0.210	0.260	0.280
	(lb/hr)	109.2	92.0	103.2	104.4
SNCR NOx Reduction	(%)	50.0%	40.0%	50.0%	35.0%
Controlled NOx	(lb/MMBtu)	0.120	0.126	0.130	0.182
	(lb/hr)	54.6	55.2	51.6	67.9
NOx Removed	(lb/hr)	54.6	36.8	51.6	36.6
SCR NOx Reduction	(%)	44.4%	29.9%	35.7%	7.9%
Controlled NOx	(lb/MMBtu)	0.067	0.088	0.084	0.168
	(lb/hr)	30.4	38.7	33.2	62.5
NOx Removed	(lb/hr)	24.2	16.5	18.4	5.4
Overall NOx Reduction	**(%)**	**72.2%**	**57.9%**	**67.9%**	**40.1%**
Expected Temperature At Bullnose Elevation	(°F)	1700-1800	1750-1850	1750-1850	1950-2050
Expected NOxOUT® A Consumption @ Load	(gph)	35.2	22.7	33.3	21.4
Average NH³ Slip As Measured @ Stack	(ppmvdu)	5	5	5	5
In-furnace CO Limit At Bullnose Elevation	(ppm)	250	250	250	100
Reagent Distribution Strategy	Level 1	6	6	6	6
	Level 2	3	3	3	3

Process Design Comments

* A static mixing device will be required to produce the inlet conditions dictated by the catalyst vendor.

* NGC and SOG flows are given under acfm conditions. For Test 5, the total GHI is 438 MMBtu/hr. Since the bark flow and oil flow are known (and their HHV is known as well) the GHI from NGC can be back-calculated and from that the scfm. It is assumed that SOG (which is methanol vapor) acts exactly like NGC. Since the oxygen content was not provided, the amount of excess air was increased to about 55% so that the flue gas flow would match the provided 135,000 dscfm. For Test 7, where oil is the only fuel, a more typical amount of excess air (~25%) was used.

FTI EQUIPMENT SCOPE OF SUPPLY SUMMARY

	G-P Palatka No. 4 Combination Boiler	
NOxOUT Design Option	NOxOUT® SNCR	NOxOUT Cascade ®
10,000 gallon FRP Storage Tank	1	1
SLP3-C Circulation Module	1	1
FRP Circulation Module Enclosure	1	1
PV1001 Chemical Circulation Control	1	1
	Urea & Dilution Water Metering	
SLP3-MS-ILC Metering Module	1	1
	Diluted Urea & Atomizing/Cooling Air Distribution Lower Level of Wall Injectors	
SLP3-D-6 Distribution Module	1	1
Wall-mounted Injector with Automatic Retract	6	6
Retract Control Panel	1	1
	Diluted Urea & Atomizing/Cooling Air Distribution Middle Upper Level of Wall Injectors	
SLP3-D-3 Distribution Module	1	1
Wall-mounted, Fixed Position Injector	3	3
Retract Control Panel	Not Required	Not Required
	Diluted Urea & Atomizing/Cooling Air Distribution Upper Level of Injection – Multiple Nozzle Lances	
Catalyst – Plate, Corrugated or Honeycomb Design	Not Applicable	121 m³
Acoustic Cleaning Device	Not Applicable	12
SCR Reactor Design, Cold Flow Modeling, and Engrg	Not Applicable	LOT
SCR Reactor Ductwork, Structural Support, Civil	Not Applicable	Not Included
	Additional Equipment and Services	
Optical Pyrometer Temperature Monitor	1	1
PLC Controls & Interface Support	1	1

FUEL TECH EQUIPMENT SCOPE OF SUPPLY

FRP NOxOUT®A UREA STORAGE TANK

Made of Fiberglass Reinforced Plastic (FRP) with Premium Grade Vinylester Resin. Fabricated per ASTM D3299-88 where applicable, 1.5 Specific Gravity, heating package to maintain 80°F, site specific variables include seismic zone, wind load, snow load, and temperature variance.

Also includes heat trace and insulation with thermostat control, level transmitter, manway, vent, internal downpipe, external fill pipe, thermocouple, ladder, hold down and lifting lugs, FRP flanges for inlet and outlet, and fill and circulation line valves for suction isolation, drain, and return control.
10,000 Gallon Capacity: 10' OD × 17' SS × 18" OAH; Approx. Empty Weight: 2,400 lbs.
Reference FTI Drawing C-1

SLP3-C CIRCULATION MODULE

The Circulation Module is designed for the continuous circulation and heating of the NOxOUT® A chemical and the supplied feed of the reagent into the Metering Module(s). The NOxOUT® tank level indication and alarms will be mounted on this module adjacent to the local control panel.

The Circulation Module includes: Complete assembly and testing, local control panel (NEMA 4X), redundant SS centrifugal pumps with auto switch, TEFC motors, motor starters, stainless steel skid with basin, 3 kW electric heater, duplex strainer for chemical, flow sensor and indicator for NOxOUT® A reagent, reagent temperature indicator, tank level indication, and all necessary SS components, piping, (Schedule 40 socket welded), and fittings.
Typical size: (4"W × 7'L × 6'H); Approximate Weight: 1,500 lbs.
Reference FTI Drawing D-1

PCV1001 CHEMICAL CIRCULATION CONTROL

The pressure control loop regulates the NOxOUT urea pressure for the High Flow Delivery Module supply to the Metering Modules in order to maintain the proper flow rate and pressure. This valve station maintains a sufficient chemical pressure upstream of the Metering Modules to allow for proper maintenance of the NOxOUT urea flow. Each valve station, specifically sized for the application, is a pre-fabricated piping spool piece consisting of a stainless steel pressure control valve, manual bypass valve, pressure transmitter, local pressure indicator, isolation valves, stainless steel piping, fittings, etc.
Reference FTI Drawing J-7

FUEL TECH EQUIPMENT SCOPE OF SUPPLY
(Continued...)

CIRCULATION MODULE ENCLOSURE

Fuel Tech provides Switzer 9000 Series modular enclosures to house certain system modules. The enclosures are constructed of fiberglass reinforced isopthalic plastic resin and molded-in color gel coat with ultraviolet inhibitors. Each building is specifically designed for the individual application with reinforced walls and flooring. Lifting lugs and structural design and analysis is performed where needed.

The enclosure includes the pre-installed Circulation Module, two (2) large service doors, heater, electrical outlets, lighting, electrical breaker panel with circuits and transformer specifically sized for application, and steel flooring system. All utility connections will be made to exterior of the enclosure.
Reference FTI Drawing A-22, J-9

SLP3-MS-ILC METERING MODULE

This module is designed for Independent Level Control, which permits a biasing of the chemical to each injection level that is in operation. The Metering Module provides flow and pressure control for the fluids used in the NOxOUT® Process – NOxOUT® A Urea and Dilution Water. The water supply will be adjusted, via a regulator, to a set pressure that will allow for proper flow to each Distribution Module. The corresponding flow of NOxOUT® A is then fed, by use of a metering pump and a digital indicating controller, into the dilution water discharge line and through a static mixer. A water/boost pump is supplied to power the mixed chemical up to each injector level at the proper pressures and flow rates. The local control panel on this module can operate in local or remote. In the remote mode the FTI-supplied PLC can automatically feed the optimized amount of NOxOUT® A reagent water pressure through the use of a 4-20 mA signal. Automatic flush of the system is also provided to clear chemical from the lines prior to shutdown.

Also includes complete assembly and testing, two (2) local control panels with PLC (NEMA 4X), three (3) SS metering pumps with AC motors and drive controllers, three (3) turbine/boost pumps with TEFC motors and motor starters, stainless steel skids with basin, three (3) static mixers, three (3) magnetic flow meters with digital indicating controllers to electronically indicate and control the precise chemical flow, three (3) magnetic flow meters, pressure control valves, pressure transmitters and indicator for controlling water flows, motor operated ball valves for chemical and water inlet, duplex strainer for water, air pressure switch, regulators for water inlet chemical calibration columns, and all necessary components, SS Schedule 40 socket-welded piping, SS butt-welded tubing, and fittings.
Typical Size: 4' W × 12' L × 6.5' H – Approximate Weight: 3,000 lbs.
Reference FTI Drawing E-4

FUEL TECH EQUIPMENT SCOPE OF SUPPLY
(Continued...)

SLP3-D-X DISTRIBUTION MODULE

The Distribution Modules are placed just prior to the injectors (typically at the same elevation) and are used as a guide and check for proper injector performance. Air for atomization and cooling is introduced through this module. One panel is supplied for each injector. They are grouped and pipe-manifolded together for ease of installation.

Also includes the necessary panels per module. Complete assembly and testing, flow and pressure indication with regulators for chemical and atomizing air. Each panel will be mounted to a freestanding stainless steel base and a pipe-manifold assembled for easy flow accessibility.
Typical Size: (SLP3-D-6) 2' W × 6.6' L x 6' H; Approximate weight: 600 lbs.
Typical Size: (SLP3-D-3) 2' W × 3.3' L x 6' H; Approximate weight: 300 lbs.
Reference FTI Drawing F-1, F-2

SLP3-I-NFTL INJECTOR ASSEMBLY

The urea injector assemblies are installed at the furnace elevation determined by our process modeling with each appropriately sized and characterized for proper flows and pressures required to achieve the necessary NOx reductions. The injectors are constructed entirely of 316L stainless steel. The nozzle tip is a ceramic-coated 316L stainless steel. The cooling shield is typically 3/4" Inconel tubing or 316 stainless steel with ceramic coating (0.750" OD and 0.065" wall thickness). The inner atomization tube is typically 3/8" tubing with an adapter to accept different injector tips, with a standard length of 2.5 feet.

Each assembly includes Fuel Tech air atomized injector, adapter for insertion adjustment, coupler to attach to boiler support, quick-connects and 6' long steel-braided flex hoses for both the chemical and atomizing air connections.
Reference FTI Drawing G-1

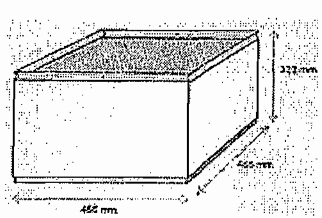
FUEL TECH EQUIPMENT SCOPE OF SUPPLY
(Continued...)

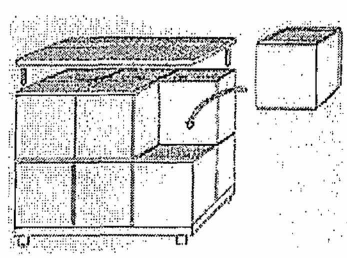
CATALYST for SCR PORTION of HYBRID

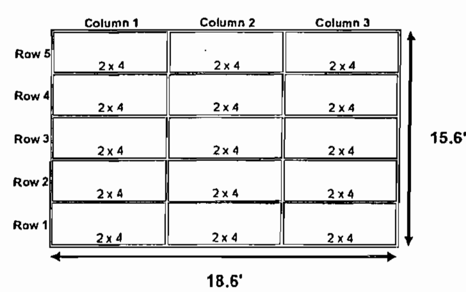
The proposed catalyst features a corrugated, fiber reinforced titanium dioxide (TiO_2) carrier. The carrier is impregnated with the active components: vanadium pentoxide (V_2O_5) and tungsten trioxide (WO_3). The catalyst is shaped to a monolithic structure with a large number of parallel channels. This catalyst design provides a highly porous structure with a large surface area and an ensuing large number of active sites. Some of the benefits of the proposed catalyst are:

- A high NOx removal level with minimum ammonia slip
- A low activity towards SO_2 oxidation, minimizing the risk of fouling downstream equipment
- A high poison resistance ensuring a long and stable service life
- A substantially lower weight than for conventional plate or extruded catalysts, allowing a fast response to changes in operation

The proposed catalyst layout consists is a two layer design comprised of individual catalyst "cassettes" (left) assembled to form a module like that show below in the center picture. The picture (below, center) shows a typical arrangement for each layer. The Loading Diagram (below, right) illustrates a design that consists of fifteen modules each having a total of eight (8) cassettes: four wide by two deep.







Specific requirements for this project would follow at a later date.

FUEL TECH SCOPE OF SUPPLY
(Continued...)

ACOUSTIC CLEANING SYSTEM

Acoustic cleaners are pneumatically operated horns that produce low frequency, high-energy sound waves. The sound waves fracture particulate deposits that have bonded to mechanical parts and other surfaces in the SCR system. As opposed to other methods of cleaning, sound waves generated by acoustic horns do not cause structural damage and have proven to be effective in the harshest operating environments.

The acoustic cleaners are operated in a semi-aggressive sequence to minimize the potential for ash buildup in the catalyst. Each horn generally is sounded for a period of ten (10) seconds every ten (10) minutes. This operating sequence has proven to be the optimum program for cleaning coal fly ash.

Acoustic cleaners have only one moving part, a titanium diaphragm. The diaphragm is housed in the sound generator of the acoustic horn. This diaphragm is cut from a square piece of titanium, stress relieved and machined on both sides to ensure uniform thickness and maximum diaphragm life.

The bell section of the acoustic cleaner is fabricated using stainless steel – this is the only portion of the acoustic cleaner that is inserted into the flue gas stream. The remaining bell sections and sound generator are machined cast pieces that are painted for corrosion protection.

TEMPERATURE MONITORING SYSTEM

The temperature monitoring system supplied by Fuel Tech is an optical pyrometer designed to continuously monitor the furnace flue gas temperature. The temperature monitor senses the visible light from the ash particles to determine the flue gas temperature. Temperature readings are not biased by unit wall temperatures and can provide temperature readings for units firing coal, wood waste, municipal solid waste, refuse derived fuels, heavy oil or any other fuel which produce glowing particles during combustion.

The temperature sensed by the monitor will be utilized in determining the proper zone of injection for the NOxOUT process. By properly selecting the zone of injection based on flue gas temperature, the NOxOUT process can be optimized with regard to NOx reduction, chemical flows, and ammonia slip. This temperature control signal allows the Fuel Tech engineers to optimize the system operation and provide the best available SNCR system. The temperature monitor will require the following utilities and connections in order to be installed and operate properly:

FUEL TECH SCOPE OF SUPPLY
(Continued...)

- 3" threaded pipe nipple extending 4-6 inches outside the boiler wall
- 110 VAC power
- 60 to 80 psig plant air
- Structural support of the unit (approximately 100 lbs)

Reference FTI Drawing G-11 and G-15

CONTROL ROOM INTERFACE

Control of the ILC Metering Module is facilitated by a PLC-based control system utilizing an Allen-Bradley SLC 500 Series, DH+ or Ethernet. In addition to local control, the PLC can control the entire NOx reduction process. This is accomplished by routing to the PLC the required boiler parameters such as NOx, Oxygen, and Boiler Load. The PLC is programmed during the initial phases of the equipment construction and then tuned during the start-up testing to react to specific unit conditions.

Operator interface at the Metering Module is handled by an Allen-Bradley PanelView 550 (or 1000). This unit is a digital display which acts as the operator's window to unit operation and control. From the PanelView, the operator can monitor all of the system performance as well as control the system and adjust the automatic operation at the various load conditions. This is accomplished through the use of the display screen and the integrated keypad.

FUEL TECH SCOPE OF SUPPLY
(Continued…)

ENGINEERING

Fuel Tech will provide Project and Process Engineering and the following drawings and information:

- P&IDs
- Skid Arrangements
- Foundation Loads
- Interface Drawings
- Injector Locations
- Electrical Drawings and Bill of Materials
- Pump Performance Curves

ENGINEERING SERVICES

- Computational Fluid Dynamics and Kinetic Modeling
- SCR Reactor Design and Flow Modeling for Cascade Option
- Project Engineering
- Start-up and Optimization Service (20 Man-days for SNCR, 40 Man-days for Hybrid)
- Operation and Maintenance Manuals (5)

SCOPE OF SUPPLY BY OTHERS

1. Installation of Fuel Tech, Inc. Supplied Equipment.

2. Interconnecting Piping and Wiring of Fuel Tech, Inc. Supplied Equipment.

3. Tank Foundation and Structural Support for System Modules.

4. SCR Reactor Vessel Ductwork and Structural Steel Modifications.

5. Static Mixing Device.

6. NOxOUT System Utility Estimates.

Summary of Estimated Utilities NOxOUT SNCR	Plant Air (scfm)	Instrument Air (scfm)	Reagent Flow (gph)	Dilution Water Flow (gph)	Cooling Water Flow (gpm)	480V Power (kW)	220V Power (kW)	110V Power (kW)
Bark and Oil	111	36	17	523	0	66	3	1.75
Bark, Oil, and NCG	111	36	15	525	0	66	3	1.75
Bark, Oil, NCG, and SOG	111	36	16	524	0	66	3	1.75
Oil	111	36	14	526	0	66	3	1.75
	Note 1	Note 2	Note 3	Note 4		Note 5		

Note 1: These "worst-case" estimates assume that all nine (9) injectors are in service, each using 12 scfm of plant air for urea atomization and injector tip cooling. If the lower level of injectors are not required under certain firing conditions, they will be retracted automatically and the flow through these six (6) injectors will be reduced to approximately 3 scfm each for cooling.

Note 2: These estimates include 35 scfm required to cool the temperature monitor optics and one (1) scfm for the Metering Module control valve.

Note 3: These estimates assume full load operation with this of diluted urea being distributed amongst all injectors that are in service.

Note 4: These estimates are based on the assumption that the total flow (concentrated urea + dilution water) per injector is one (1) gpm. The actual consumption rate will depend on the number of injectors in service at a given load and firing condition.

Note 5: This estimate assumes that power will be fed into the step-down transformer located in the Circulation Module enclosure and distributed as needed to serve the system components in the enclosure as well as the rest of the SNCR system.

Summary of Estimated Utilities NOxOUT Options	Plant Air (scfm)	Instrument Air (scfm)	Reagent Flow (gph)	Dilution Water Flow (gph)	Cooling Water Flow (gpm)	480V Power (kW)	220V Power (kW)	110V Power (kW)
NOxOUT SNCR (Test 2)	111	36	17	533	0	66	3	1.75
NOxOUT Cascade (Test 2)	111	36	35	525	0	66	3	1.75
	Note 1	Note 2	Note 3	Note 4		Note 5		

7. Chemical Supply: NOxOUT® Quality Licensed Reagent (50% Solution).

8. Implement Control Logic Schemes into Plant Controls System.

9. NOx, Ammonia, and CO Monitoring Equipment, if Required.

10. Required Penetrations for Injector Wall Sleeves and Mounting.

11. Asbestos Abatement, if Required.

12. System Performance Testing.

13. Spare Parts.

FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

For the Engineering, Equipment, and Services identified in this proposal, we quote the following budgetary prices, FOB Jobsite:

NOxOUT® SNCR	EIGHT HUNDRED AND SEVENTY-FIVE THOUSAND DOLLARS	$875,000.00
NOxOUT CASCADE®	TWO MILLION, NINE HUNDRED THOUSAND DOLLARS	$2,900,000.00

Price includes the stated number of start-up and optimization services man-days per unit, with travel and living expenses included. Please see our Field Service Pricing Schedule, Exhibit C1, dated January 2006, for per diem service rates.

TERMS OF PAYMENT

10% Upon receipt of Letter of Intent, Purchase Order, or Contract
20% Upon submittal of Drawings to the Buyer for Approval
20% Upon Buyer's release for equipment fabrication
10% Upon submittal of Certified Drawings to the Buyer
30% Upon date of shipment of equipment, or thirty days after notification to buyer that equipment is ready to ship, whichever occurs first.
10% After successful completion of acceptance test or six (6) months after receipt of equipment, whichever occurs first.

All invoices are payable net thirty (30) days from invoice date. Buyer shall pay interest at the rate of ten percent (10%) per annum on all overdue amounts. Buyer shall pay all Sales Tax, Use Tax, Excise Tax, or other similar taxes.

EXHIBIT C3
FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

These terms and conditions shall be part of the attached proposal and shall become part of the contract entered into between FUEL TECH, INC. (Fuel Tech), and the Buyer. Deviations from these terms and conditions must be agreed to in a writing signed by Fuel Tech and the Buyer. Fuel Tech hereby gives notice of its objection to any different or additional terms or conditions unless such different or additional terms or conditions are agreed to in a writing signed by Fuel Tech and Buyer.

1. TERMS OF PAYMENT:
   All invoices are payable net thirty (30) days from date of invoice. Buyer shall pay interest at the rate of ten percent (10%) per annum on all overdue amounts. Buyer shall pay all sales tax, use tax, excise tax, or other similar taxes.

2. DELAYS:
   If shipments are delayed by Buyer, payment shall be due on and warranty coverage shall begin to run from thirty days after the original shipment date specified in the contract or thirty (30) days after notification to Buyer that equipment is ready to ship, whichever is earlier. Risk of loss shall pass to Buyer at the time that equipment is identified, and any costs caused by such delay shall be borne by Buyer.

   If shipments are delayed by Buyer, Fuel Tech will ship the equipment no later than sixty (60) days after initial notification to the Buyer that the equipment is ready for shipment. Buyer agrees either (1) to provide Fuel Tech an appropriate "ship to" address and to accept delivery or (2) pay reasonable storage charges for the equipment beginning sixty (60) days after initial notification to Buyer that equipment is ready to ship.

3. PERFORMANCE GUARANTEE:
   Buyer warrants that the operating conditions of the Unit are those specified in the Process Design Table. Buyer is solely responsible for the accuracy of that operating condition information, and all performance guarantees and equipment warranties granted by Fuel Tech shall be void if that operating condition information is inaccurate or is not met. All performance guarantees and equipment warranties are conditioned on Buyer timely providing all of the equipment, materials, chemicals, utilities, and services that it has agreed to provide, on operating the Unit within the operating conditions specified in the Process Design Table, and on using reagent of license grade quality in the operation of the Unit.

EXHIBIT C3
FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

4. EQUIPMENT WARRANTY:
Fuel Tech warrants that the equipment it provides shall be free from defects in design, workmanship, and material at the time the equipment is delivered and for a period of twelve (12) months after initial operation, or eighteen (18) months from shipment of equipment, whichever occurs first. Fuel Tech does not warrant wear parts such as injection tips, cooling shields, pump diaphragms, check valves, solenoids, pump impellers, pump wear rings, pump seals, valve packing, and valve seats.

All warranties made by the manufacturer of the equipment (if that manufacturer is any entity other than Fuel Tech) shall be assigned by Fuel Tech to the Buyer, if such assignment is permissible by law and contract. Warranty coverage starts at shipment of equipment or thirty (30) days after notification to Buyer that equipment is ready to ship.

5. DISCLAIMER OF WARRANTIES:
Fuel Tech warrants its equipment and the performance of its equipment solely in accordance with the equipment warranty and performance guarantee contained in this proposal and makes no other representations or warranties of any other kind, express or implied, by fact or by law. All warranties other than those specifically set forth in this proposal are expressly disclaimed. **FUEL TECH SPECIFICALLY DISCLAIMS ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, AND DISLCAIMS THE IMPLIED WARRANTY OF MERCHANTABILITY, THE IMPLIED WARRANTY OF FITNESS FOR A PARTICULAR PURPOSE, AND ANY OTHER IMPLIED WARRANTIES OF DESIGN, CAPACITY, OR PERFORMANCE RELATING TO THE EQUIPMENT.**

6. LIMITATION OF LIABILITY:
Buyer's sole remedy under the equipment warranty and the performance guarantee shall be to allow Fuel Tech, at Fuel Tech's option, either to repair, replace, or supplement the equipment to meet the performance guarantee, or, in the event that those options are not feasible, to remove the Equipment and refund the contract price to Buyer. NOTWITHSTANDING ANYTHING TO THE CONTRARY, FUEL TECH'S TOTAL LIMIT OF LIABILITY ON ANY CLAIM, WHETHER FOR BREACH OF CONTRACT, BREACH OF WARRANTY, TORT, NEGLIGENCE, STRICT LIABILITY, OR ANY OTHER LEGAL THEORY, FOR ANY LOSS OR DAMAGE ARISING OUT OF, OR CONNECTED TO, OR RESULTING FROM THIS AGREEMENT, INCLUDING WITHOUT LIMITATION AMOUNTS INCURRED BY FUEL TECH OR BUYER IN ATTEMPTING TO REPAIR, REPLACE, OR SUPPLEMENT THE EQUIPMENT OR MEET THE PERFORMANCE GUARANTEE, SHALL BE LIMITED TO THE CONTRACT PRICE TO BE PAID BY BUYER PURSUANT TO THE CONTRACT.

EXHIBIT C3
FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

7. EXCLUSION OF CONSEQUENTIAL DAMAGES:
NOTWITHSTANDING ANYTHING TO THE CONTRARY, IN NO EVENT SHALL FUEL TECH BE LIABLE FOR ANY INDIRECT, CONSEQUENTIAL, INCIDENTAL, SPECIAL, OR PUNITIVE DAMAGES, INCLUDING BUT NOT LIMITED TO LOSS OF CAPITAL, LOSS OF REVENUES, LOSS OF PROFITS, LOSS OF ANTICIPATORY PROFITS, LOSS OF BUSINESS OPPORTUNITY, DAMAGE TO EQUIPMENT OR FACILITIES, COST OF SUBSTITUTE NOx REDUCTION SYSTEMS, DOWNTIME COSTS, GOVERNMENT FINES, OR CLAIMS OF CUSTOMERS, EVEN IF ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

8. RESPONSIBILITY FOR THIRD PARTIES
Buyer shall at all times be responsible for the acts and omissions of its subcontractors and of any other third parties hired or retained or contracted by Buyer to perform work or provide equipment related to the system provided by Fuel Tech, including but not limited to third party design, systems integration, equipment tie-in, or process design changes. Fuel Tech shall have no responsibility for ensuring the accuracy of any such work or the performance of any equipment provided by subcontractors or third parties hired or retained or contracted by Buyer, and Buyer assumes all liability for any such work or equipment and for any failures in Fuel Tech's equipment caused by any such subcontractors or third parties hired or retained or contracted by Buyer. Buyer agrees to indemnify, hold harmless, and defend Fuel Tech from any claims, losses, damages, injuries, or failures caused by any such subcontractors or third parties.

9. CONFIDENTIALITY:
Buyer agrees that it shall hold Confidential Information received from Fuel Tech in the strictest confidence, shall not use the Confidential Information for its own benefit except as necessary to fulfill the terms of the agreement between the parties, shall disclose the Confidential Information only to employees, agents, or representatives who have a need to know the Confidential Information, shall not disclose the Confidential Information to any third party, shall not copy the Confidential Information, shall not disassemble, decompile, or otherwise reverse engineer the Confidential Information and any inventions, processes, or products disclosed by Fuel Tech, and, in preventing disclosure of Confidential Information to third parties, shall use the same degree of care as for its own information of similar importance, but no less than reasonable care.

10. LICENSE AGREEMENT AND OTHER TERMS:

Sale is subject to agreement on other terms and conditions, including a Sale of Equipment with License Agreement.

EXHIBIT C3
FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

11. INDEMNIFICATION:
Each Party shall defend, indemnify, and hold harmless the other Party and its employees, agents, and representatives from any claims, liabilities, lawsuits, costs, losses, or damages that arise out of or result from any negligent or willful acts or omissions of the indemnifying Party's employees, agents, or representatives. Where such claims, liabilities, lawsuits, costs, losses, or damages are the result of the joint or concurrent negligence or willful misconduct of the Parties or their respective agents, employees, representatives, subcontractors, or any third party, each Party's duty of indemnification shall be in the same proportion that the negligence or willful misconduct of such Party, its agents, employees, representatives, or subcontractors contributed thereto. The Party entitled to indemnity under this Agreement shall promptly notify the indemnifying Party of any indemnifiable claim, liability, lawsuit, cost, loss, or damage. The Party responsible for indemnification under this Agreement shall conduct and control the defense of the indemnified claim, liability, lawsuit, cost, loss, or damage. The Parties shall use their best efforts to cooperate in all aspects of the defense of any such claim, liability, lawsuit, cost, loss, or damage. The indemnifying Party shall not be bound by any compromise or settlement made without its prior written consent.

12. FORCE MAJEURE
The Parties shall be excused from liability for delays in manufacture, delivery, or performance due to any events beyond the reasonable control of the Parties, including but not limited to acts of God, war, national defense requirements, riot, sabotage, governmental law, ordinance, rule, or regulation (whether valid or invalid), orders of injunction, explosion, strikes, concerted acts of workers, fire, flood, storm, failure of or accidents involving either Party's plant, or shortage of or inability to obtain necessary labor, raw materials, or transportation ("Force Majeure"). Any delay in the performance by either party under this Agreement shall be excused if and to the extent the delay is caused by the occurrence of a Force Majeure, provided that the affected party shall promptly give written notice to the other party of the occurrence of a Force Majeure, specifying the nature of the delay, and the probable extent of the delay, if determinable.

Following the receipt of any written notice of the occurrence of a Force Majeure, the parties shall immediately attempt to determine what fair and reasonable extension for the time of performance may be necessary. The parties agree to use reasonable commercial efforts to mitigate the effects of events of Force Majeure.

No liabilities of any party that arose before the occurrence of the Force Majeure event shall be excused except to the extent affected by such subsequent Force Majeure.

EXHIBIT C3
FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

13. GOVERNING LAW
This Agreement shall be governed by and interpreted in accordance with the laws of the State of Illinois, excluding its choice of laws rules. The parties shall attempt to settle any disputes, controversies, or claims arising out of this Agreement through consultation and negotiation in good faith and in a spirit of mutual cooperation. If those attempts fail, then any dispute, controversy or claim shall be submitted first to a mutually acceptable neutral advisor for mediation. Neither party may unreasonably withhold acceptance of a neutral advisor. The selection of the neutral advisor must be made within forty-five (45) days after written notice by one party demanding mediation, and the mediation must be held within six months after the initial demand for it. By mutual agreement, however, the parties may postpone mediation until they have each completed some specified but limited discovery about the dispute, controversy, or claim. The cost of mediation shall be equally shared between the parties. Any dispute that the parties cannot resolve through mediation within six (6) months after the initial demand for it may then be submitted to a state or federal court of competent jurisdiction within the State of Illinois for resolution. The use of mediation shall not be construed (under such doctrines as laches, waiver, or estoppel) to have adversely affected any party's ability to pursue its legal remedies, and nothing in this provision shall prevent any party from resorting to judicial proceedings if good faith efforts to resolve a dispute under these procedures have been unsuccessful or interim resort to a court is necessary to prevent serious and irreparable injury to any party or others.

14. ENTIRE AGREEMENT
This Exhibit C3 and the Fuel Tech Proposal attached to it constitute the entire agreement between the parties and can be modified only in writing signed by authorized representatives of each of the parties.

FUEL TECH®

Technology for a renewed environment™

Proposal No. 04-B-008, Rev 2
NOxOUT® SNCR & NOxOUT Cascade®
NOx Reduction System Options

For

Golder Associates, Inc.
Gainesville, Florida
Project No. 0537627-0200

Georgia-Pacific Corporation
Palatka, FL Mill
No. 4 Combination Fuel Boiler

February 22, 2006

PROPOSAL SUMMARY

In support of efforts underway at Golder Associates and G-P to identify and evaluate post-combustion NOx reduction alternatives for the No. 4 Combination Boiler at the Palatka Mill, Fuel Tech, Inc. (FTI) is pleased to submit our revised budgetary proposal covering the design, supply, fabrication, delivery, personnel training and commissioning of NOxOUT® NOx reduction system options. These NOx reduction options include NOxOUT® SNCR Selective Non-catalytic NOx Reduction and our hybrid SNCR/SCR NOx reduction process, NOxOUT Cascade®.

In our Revision 1 proposal dated January 5, 2006, four (4) SNCR performance cases were presented for the potential combinations of fuel fired in this boiler. As noted in that proposal, NOx reduction via SNCR is limited by a number of factors, such as boiler design, combustion byproducts, upper furnace flue gas temperature, flue gas velocity and residence time available to the SNCR process, furnace access for reagent distribution purposes, sulfur content of the fuel being fired, flue gas temperature at the outlet of the air preheater, and the concentration of ammonia slip that can be tolerated for the specific application. Some of these factors individually affect SNCR NOx reduction performance and others can have a combined influence on the SNCR process – sulfur content and ammonia slip are factors that must be considered in combination when evaluating SNCR performance.

The SNCR performance cases, restated in this Revision, highlight the challenges that the post-combustion conditions present to the SNCR. For this application these challenges, among others, include relatively high CO and the need to control NH3 slip in order to limit the potential formation of ammonium bisulfate (ABS). In order to control ammonia slip, urea must be injected at a higher than ideal temperature – we call this “right side of the slope” injection – which has a direct impact on chemical utilization and NOx reduction performance. The CO present in the flue gas at the point of injection effectively shortens the residence time for the SNCR process reactions, thereby placing an additional restriction on the potential for NOx reduction. If the controlled NOx emissions target is lower than what can be achieved via SNCR or a specific compliance scenario requires lower emissions from this boiler, the SNCR process can be combined with a downstream catalyst to further reduce the NOx emission rate and the ammonia present at the stack.

If the urea reagent is injected at a higher elevation in the furnace (still within the effective temperature window) and the chemical is released at a lower temperature, the SNCR process is operated at a higher point on the process efficiency curve and chemical utilization is greatly improved. Ammonia slip increases when SNCR is operated under these conditions, but the additional slip serves as the reagent for the NOx reduction achieved downstream in the SCR catalyst.

PROPOSAL SUMMARY continued...

Assuming NOx reduction levels of 85-90% are not required, there are other benefits to this approach as compared to a conventional SCR system, including:

- NOx reduction required from the SCR is reduced which relaxes the restrictions on the inlet conditions, such as NH3:NOx distribution, temperature distribution, and flue gas velocity distribution, and
- The treatment length in the catalyst bed (catalyst volume requirements) can be reduced which has an impact on overall pressure drop, catalyst replacement costs, and total weight of the SCR system.

Because the average velocity of the flue gas entering the SCR reactor must be controlled to the level required by the application and the guarantees offered by the catalyst vendor, the cross-sectional area of the duct which houses the SCR reactor is the same for either approach.

Generally speaking, NOx reduction via the NOxOUT Cascade process can be cost-effective when the catalyst can be installed within the confines of the existing ductwork where the cross-sectional area can be expanded to slow the flue gas down to the velocity dictated by the catalyst vendor. When extensive ductwork or structural modifications are required to provide the necessary process conditions, the added cost can be prohibitive.

NOx Reduction Control Options

Depending on the controlled NOx emission rate required for this project, FTI has provided an option for a conventional NOxOUT® SNCR system. By the term "conventional" SNCR we are referring to SNCR that employs multiple levels of wall-mounted injectors. The theory (and practice) behind using multiple levels of injection and a feed-forward/feedback control loop that tracks boiler operation and NOx reduction performance, is that the injector level(s) in-service will change automatically with the boiler load (steam flow) and accompanying shifts in the effective "temperature window" for the SNCR process. For base-loaded operation, the flow of concentrated urea would be biased between these levels or possibly directed to only the upper elevation if this provides the best NOx reduction performance and NH3 slip control.

Some the guidelines for these automatic shifts in injector operation (as a function of steam flow or fuel firing rate) will be defined during the modeling phase of the project and the remainder will be determined at the time of system startup and optimization. Flow rates and atomization pressures for each injector that correspond to specific load and firing conditions are programmed into the PLC or DCS control tables.

PROPOSAL SUMMARY continued...

One way to open up the effective temperature window for a given application is to move injectors up out of the upper furnace and into the convection pass. Standard injectors in the upper furnace produce relatively large droplets of water-encapsulated, atomized urea. The NOxOUT SNCR process relies on the targeted injection and momentum of these droplets to carry the urea, which eventually is converted into gas-phase ammonia, into predetermined areas of the furnace where the NH3 molecules will react selectively with NOx. Relatively speaking, these droplets are large and they require a certain amount of residence time to evaporate before the ammonia is released and they finally come into contact with the ammonia molecules – this is the point in time at which the selective reaction occurs. Any ammonia that leaves the process boundary unreacted will show up downstream as ammonia slip, and because this unreacted ammonia can combine to form undesirable byproducts, this is the limiting factor for the SNCR process.

As our preliminary design for this application indicates, these standard wall injectors can generally achieve a higher level of SNCR NOx reduction if the chemical is released at a lower temperature. For the hybrid system in this particular case, the SNCR NOx reduction would improve nominally from 30-35 percent to as much as 50 percent, and using a downstream catalyst to absorb the increased level of ammonia slip would result in an overall NOx reduction is excess of 70%. The SNCR and Cascade performance details for each firing scenario are included in the Process Design Tables that follow this section of our proposal.

TECHNOLOGY OVERVIEW: NOxOUT® SNCR Process Description

NOxOUT® SNCR is a patented in-furnace, post-combustion NOx reduction technology that relies on the finely controlled distribution of urea to effect a selective reaction of gas-phase ammonia with NOx within a specific temperature region in the upper furnace. The urea is delivered and stored as a 50% aqueous solution that is continuously circulated through the stainless steel SNCR system piping loop. Using plant service water, a metering module located near the injection elevation further dilutes the reagent to a predetermined concentration and precisely controls the flow of diluted reagent to distribution modules located at each injection elevation. The distribution modules provide the final control of diluted reagent and atomizing (plant) air being delivered to each injector, where droplet size and trajectory for each injector have been determined through advanced computer modeling. The final spray characteristics and flow rate of diluted reagent for each injector are fine-tuned during system optimization and startup to correspond to specific boiler operating loads and NOx concentrations.

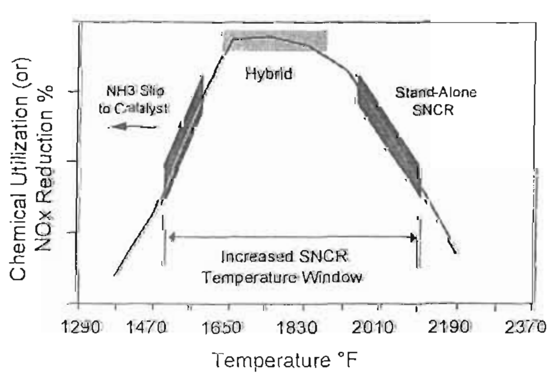
PROPOSAL SUMMARY continued...

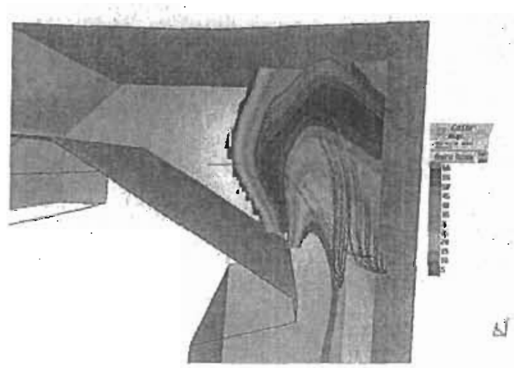
Using feedback NOx emission signals from the CEMS (if available) and these optimized settings, the SNCR system runs in the background under the control of an on-board Allen-Bradley SLC 500 Series PLC (DH+ or Ethernet) and is transparent to the other plant operations. The NOxOUT system information will be available to the operators on a control room computer display or can be tied directly into the plant Distributive Control System if one is available.

TECHNOLOGY OVERVIEW: NOxOUT Cascade® Process Description

Within the NOxOUT Cascade Process are two proven NOx reduction technologies. The first of these is the NOxOUT® SNCR Process which utilizes a stabilized aqueous urea solution that will react with NOx under the appropriate conditions to produce elemental nitrogen, water vapor and trace amounts of carbon dioxide. One of the limiting factors for NOxOUT® SNCR has been the amount of ammonia slip that is allowed to occur. Once the ammonia slip maximum is reached in the system design phase, work towards further NOx reduction must cease if that additional NOx reduction would result in the ammonia slip limit being exceeded. NOxOUT® SNCR has addressed this concern by utilizing what is known as "right side of the slope" injection technology which helps to minimize the amount of ammonia produced while providing significant levels of NOx reduction.

As illustrated by the graph below and the accompanying snapshot from one of our process models, SNCR NOx reduction efficiency and chemical utilization are improved by releasing the chemical at a lower temperature. A controlled, higher concentration of NH3 slip is directed to the SCR catalyst where the ammonia is absorbed and an incremental increase in NOx reduction performance can be achieved. Considerable work indicates that the most cost-effective level for NOxOUT Cascade occurs when the NOxOUT® SNCR component is maximized for NOx reduction.





PROPOSAL SUMMARY continued...

Conventional SCR technology requires the injection of ammonia, either aqueous or anhydrous, into the flue gas prior to the flue gas passing over the surface of a catalyst that is specifically designed to encourage the reduction of NOx. This requires tightly controlled reactor inlet conditions and the maintenance and operation of equipment especially designed to handle and feed the ammonia reagent. The ammonia handling equipment typically consists of a pressure vessel for storage, an evaporator or vaporizer to convert the ammonia to a gaseous phase, a compressor or blower, and an ammonia injection grid. The utility requirements for this equipment generally are high since the evaporator operates at a high temperature and the blower must move very large volumes of gas.

Other related costs with ammonia storage and handling systems include the process safety management and communications requirements established by the Occupational Safety and Health Administration. These regulations require annual reporting of any stored highly hazardous chemicals and annual studies of personal safety and environmental concerns to protect neighboring communities in the event of an accidental release. The NOxOUT Cascade System has incorporated the positive features of the SCR by utilizing a catalyst to further reduce NOx emissions from the NOxOUT® SNCR system but has eliminated all ammonia handling requirements so that the expenses and safety and environmental concerns are removed.

The NOxOUT® SNCR Process for this hybrid system approach is designed to generate a higher, controlled level of ammonia slip from the SNCR process boundary that will become thoroughly mixed in the flue gas. This process-managed ammonia slip then becomes the reducing agent for the reactions that occur in the SCR reactor as the flue gas passes over the catalyst surface. The ammonia that is present will react with the available NOx, further reducing the outlet NOx emissions and the concentration of unreacted ammonia leaving the reactor vessel.

In addition to eliminating the need to store and handle highly hazardous chemicals, the NOxOUT Cascade Process requires a shorter treatment length than would be required by a standalone SCR to achieve the same overall level of NOx reduction. With the NOxOUT Cascade System, a high percentage of NOx is reduced by the NOxOUT® SNCR process, leaving the SCR portion to add only incremental NOx reduction and absorption of the higher level of ammonia slip from the SNCR process. Although the volume of flue gas and the inlet area required for the SCR reactor are the same, the reduced workload on the SCR portion translates into a shorter treatment length and a smaller reactor vessel, lower pressure drop for the system, and fewer constraints on the SCR inlet conditions. In many cases, fan replacements can be avoided along with the costs of a complete system draft analysis. In addition, catalyst replacement costs may be reduced significantly since the volume of catalyst exposed to contaminants in the flue gas is reduced.

PROPOSAL SUMMARY continued...

FTI Scope of Supply

The Fuel Tech Equipment Scope of Supply detailed in this proposal includes:

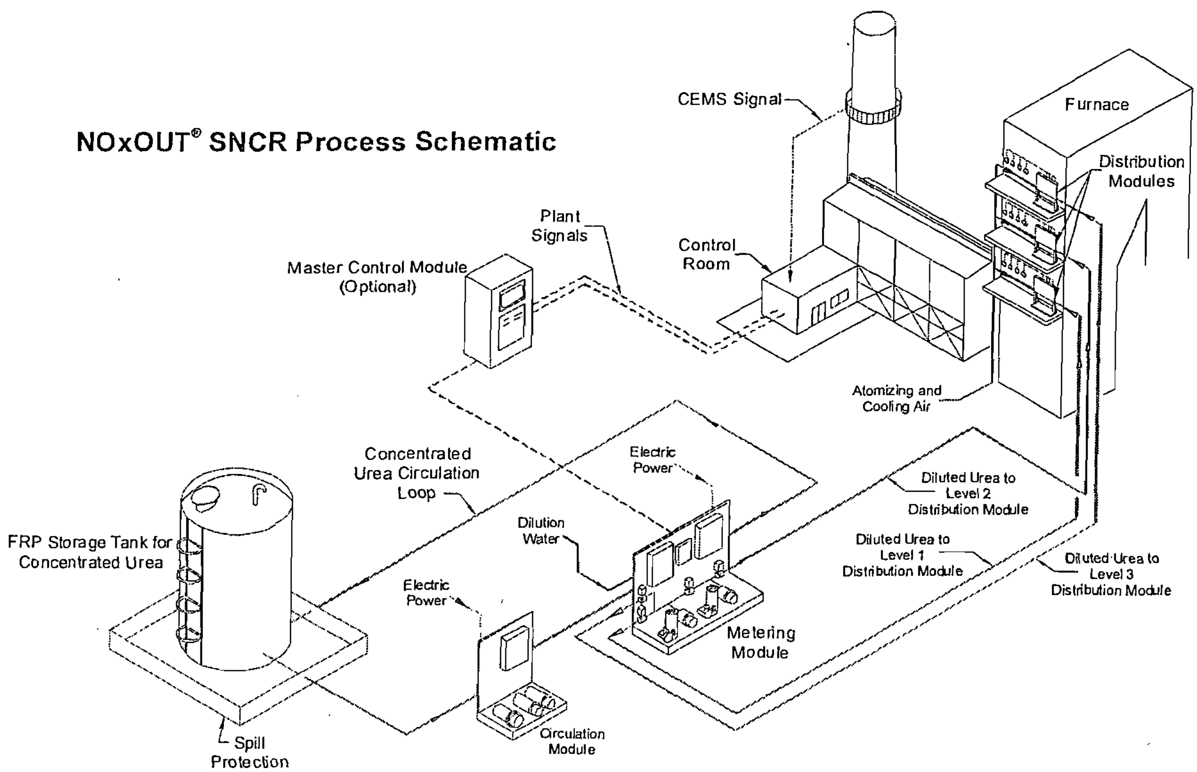
- One (1) double-wall FRP reagent storage tank with all required appurtenances,
- One (1) reagent circulation module to provide a continuous flow of the reagent to the circulation loop piping – the temperature of the concentrated reagent must be maintained at a sufficient level to minimize the potential for crystallization, generally requiring that this loop be heat traced and possibly insulated,
- Multiple-level, Independent Level Control (ILC) Metering module with an on-board water boost pump (WBP) to control the reagent and dilution water flow rates and deliver a consistent urea droplet concentration to the distribution modules and injectors, and
- Distribution modules to provide fine, individual control of the diluted and atomized reagent being delivered into the boiler via the wall-mounted injectors.

Descriptions of the individuals components identified in the FTI Equipment Scope of Supply summaries, including the module descriptions, estimated module weights and dimensions, are provided later in this Proposal. Expected system utility requirements such as dilution water flow rates, atomizing/cooling air flow rates, and electric power consumption also are provided.

PROPOSAL SUMMARY
(Continued...)

The proposed equipment for this project would be configured very closely to what is illustrated below in the SNCR Process Schematic, with the exception that the SNCR system would have only two (2) levels of urea injection.

NOxOUT® SNCR Process Schematic



PROCESS DESIGN TABLE – NOxOUT SNCR

B&W Combination Fuel Boiler No. 4

Design Case		**Bark & Oil**	**Bark, Oil, NCG**	**Bark, Oil, NCG, SOG**	**Oil**
October 2005 Testing		**No. 2**	**No. 5**	**No. 6**	**No. 7**
Furnace Design		Stoker	Stoker	Stoker	Stoker
Maximum Heat Input	(MMBtu/hr)	455.0	438.0	397.0	373.0
Uncontrolled NOx	(lb/MMBtu)	0.240	0.210	0.260	0.280
	(lb/hr)	109.2	92.0	103.2	104.4
SNCR NOx Reduction	(%)	35.0%	30.0%	35.0%	25.0%
Controlled NOx	(lb/MMBtu)	0.156	0.147	0.169	0.210
	(lb/hr)	71.0	64.4	67.1	78.3
NOx Removed	(lb/hr)	38.2	27.6	36.1	26.1
Expected Temperature At Bullnose Elevation	(°F)	1700-1800	1750-1850	1750-1850	1950-2050
Expected NOxOUT® A Consumption @ Load	(gph)	17	15	16	14
Average NH^3 Slip As Measured @ Stack	(ppmvdu)	15	15	15	5
In-furnace CO Limit At Bullnose Elevation	(ppm)	250	250	250	100
Reagent Distribution Strategy	Level 1	6	6	6	6
	Level 2	3	3	3	3

Process Design Comments

* The high sulfur content in the fuel for the oil firing case requires that allowable NH3 slip be reduced to limit the potential formation of ammonium bisulfate, thereby limiting the SNCR NOx reduction that can be achieved.

** The preliminary design calls for retract mechanisms on the six (6) lower (Level 1) injectors. The position of the upper (Level 2) level injectors would be fixed.

PROCESS DESIGN TABLE – NOxOUT CASCADE

B&W Combination Fuel Boiler No. 4

Design Case		Bark & Oil	Bark, Oil, NCG	Bark, Oil, NCG, SOG	Oil
October 2005 Testing		**No. 2**	**No. 5**	**No. 6**	**No. 7**
Furnace Design		Stoker	Stoker	Stoker	Stoker
Maximum Heat Input	(MMBtu/hr)	455.0	438.0	397.0	373.0
Uncontrolled NOx	(lb/MMBtu)	0.240	0.210	0.260	0.280
	(lb/hr)	109.2	92.0	103.2	104.4
SNCR NOx Reduction	(%)	50.0%	40.0%	50.0%	35.0%
Controlled NOx	(lb/MMBtu)	0.120	0.126	0.130	0.182
	(lb/hr)	54.6	55.2	51.6	67.9
NOx Removed	(lb/hr)	54.6	36.8	51.6	36.6
SCR NOx Reduction	(%)	44.4%	29.9%	35.7%	7.9%
Controlled NOx	(lb/MMBtu)	0.067	0.088	0.084	0.168
	(lb/hr)	30.4	38.7	33.2	62.5
NOx Removed	(lb/hr)	24.2	16.5	18.4	5.4
Overall NOx Reduction	**(%)**	**72.2%**	**57.9%**	**67.9%**	**40.1%**
Expected Temperature At Bullnose Elevation	(°F)	1700-1800	1750-1850	1750-1850	1950-2050
Expected NOxOUT® A Consumption @ Load	(gph)	35.2	22.7	33.3	21.4
Average NH^3 Slip As Measured @ Stack	(ppmvdu)	5	5	5	5
In-furnace CO Limit At Bullnose Elevation	(ppm)	250	250	250	100
Reagent Distribution Strategy	Level 1	6	6	6	6
	Level 2	3	3	3	3

Process Design Comments

* A static mixing device will be required to produce the inlet conditions dictated by the catalyst vendor.

* NGC and SOG flows are given under acfm conditions. For Test 5, the total GHI is 438 MMBtu/hr. Since the bark flow and oil flow are known (and their HHV is known as well) the GHI from NGC can be back-calculated and from that the scfm. It is assumed that SOG (which is methanol vapor) acts exactly like NGC. Since the oxygen content was not provided, the amount of excess air was increased to about 55% so that the flue gas flow would match the provided 135,000 dscfm. For Test 7, where oil is the only fuel, a more typical amount of excess air (~25%) was used.

ATTACHMENT F (Q-9)

Revised Table I - 4

TABLE I-6
MAXIMUM SO_2 IMPACTS PREDICTED FOR COMPARISON TO THE SO_2 PSD CLASS I INCREMENTS AT THE OKEFENOKEE NWA

Averaging Time/Rank	Maximum Concentration[a] (µg/m³)	Receptor Location LCC Coordinates (km) X	Y	Time Period (YYMMDDHH)	PSD Class I Increment (µg/m³)
Annual					
Highest	0.00[b]	NA	NA	NA	2
	0.00	NA	NA	NA	
	0.00	NA	NA	NA	
24-Hour					
Second-highest	4.14	1,422.472	-926.620	01112924	5
	2.44	1,397.157	-930.757	02010924	
	2.25	1,397.157	-930.757	03111824	
3-Hour					
Second-highest	19.1	1,422.472	-926.620	01121221	25
	16.8	1,416.891	-912.442	02021006	
	24.4	1,419.983	-921.368	03112312	

Note: YYMMDDHH = Year, Month, Day, Hour Ending
LCC = Lambert Conic Conformal
NA = Not Applicable

[a] Based on the CALPUFF model using 3 years of CALMET meteorological data for 2001, 2002, and 2003. 4-km Florida domain.

[b] A "0.00" impact means that the predicted concentration was zero or less. The CALPUFF model does not print a negative concentration.

ATTACHMENT G (Q-10)

Revised Table I - 6

TABLE I-4
MAXIMUM PREDICTED SO_2 IMPACTS FOR COMPARISON TO THE FLORIDA AAQS

Averaging Time and Rank	Concentrations (µg/m³)[a] Total (c=a+b)	Modeled Source (a)	Background[a] (b)	Receptor Location UTM Coordinates (m) East	North	Time Period (YYMMDDHH)	Florida Ambient Air Quality Standards (µg/m³)
Highest Annual							
	27.7	21.7	6	434741	3283275	01123124	60
	25.9	19.9	6	434741	3283275	02123124	
	28.1	22.1	6	434629	3283191	03123124	
	26.6	20.6	6	434741	3283275	04123124	
	27.7	21.7	6	434704	3283247	05123124	
HSH 24-Hour							
	182	148	34	434704	3283247	01012024	260
	197	163	34	434554	3283135	02010724	
	193	159	34	434666	3283219	03121724	
	169	135	34	434704	3283247	04040224	
	183	149	34	434704	3283247	05122624	
HSH 3-Hour							
	637	509	128	434666	3283219	01011215	1,300
	642	514	128	434592	3283163	02022712	
	575	447	128	434666	3283219	03042618	
	640	512	128	434629	3283191	04041415	
	642	514	128	434629	3283191	05042718	

Note: YYMMDDHH = Year, Month, Day, Hour Ending.
HSH = Highest, second-highest
AAQS = Ambient Air Quality Standards

[a] Concentrations are based on highest concentrations predicted using AERMOD with five years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service station at Jacksonville International Airport as received from the FDEP.

[b] Background concentrations are highest mean and HSH 24-and 3-hour concentrations, measured during 2004 and 2005 from Palatka monitoring station 12-107-1008.

ATTACHMENT H (Q-11)

Batch and Continuous prescrubber TRS removal efficiency data

NCG/TRS SYSTEM CONTROL EQUIPMENT EFFICIENCIES

PRE-SCRUBBERS

Date	Time	System	Inlet, ppm	Outlet, ppm	Efficiency	Flow, gpm
05/28	1650-1720	Continuous	47500	17450	63%	80
	1720-1750		15600	8900	43%	80
	1758-1808		49900	22950	54%	80
05/29	1145-1215		274500	139520	49%	100
	1218-1248		215250	141180	50%	100
	1249-1319		274710	154240	55%	100
07/11/02	1344-1404	Continuous	281250	106100	62%	100
	1404-1420		284450	112040	61%	100
	1420-1435		303200	93440	69%	100
	Average				64%	
05/28	1530-1555	Batch	3761	1933	49%	80
	1555-1615		3987	1975	50%	80
	1615-1645		961	431	55%	80
05/29	0948-1012		16290	7260	55%	107
	1018-1048		64580	19030	71%	107
	1055-1125		35700	12120	66%	104
	Average				64%	106
07/05/02	1335-1405		76500	29400	62%	100
	1405-1445		70800	25000	65%	100
	1445-1515		166500	45920	72%	100
	Average				66%	100

Notes: 05/29, batch scrubber flow was 107 gpm 1055-1115 and 97 gpm 1115-1125.
Found some nozzle pluggage in continuous scrubber after 05/29 test.

SO_2 SCRUBBER AT ISLAND

Date	Time	Inlet, ppm	Outlet, ppm	Efficiency	Flow, gpm	PH
05/30	1357-1457	1742	3	99.8%	420	8.1
	1457-1557	1563	3	99.8%	419	7.9

CME

Date	Time	Inlet, ppm	Outlet, ppm	Inlet, #hr	Outlet, lb/hr	Efficiency ppm/#/hr
05/30		18	3	1.04	0.15	83/86%
		--	24	--	1.44	--
		47	18	2.70	0.98	62/64%

Experienced scrubber problems

From: Origin ID: (386)329-0063
Keith Wahoske
'eorgia-Pacific
.: O. Box 919
215 CR 216
Palatka, FL 32177

FedEx Express

E

CLS100306/19/23

Ship Date: 15NOV06
ActWgt: 1 LB
System#: 3377843/INET2500
Account#: S *********

REF:

Delivery Address Bar Code

SHIP TO: (850)413-9198 BILL SENDER

Jeffrey Koerner
FL Dept of Environmental Protection
2600 Blair Stone Road

Tallahassee, FL 323992400

STANDARD OVERNIGHT

THU
Deliver By:
16NOV06

TRK# 7985 4371 4662 FORM 0201

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Jeb Bush
Governor

Department of Environmental Protection

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

Colleen M. Castille
Secretary

October 27, 2006

{Sent by Electronic Mail - Return Receipt Requested}

Mr. Keith Wahoske, Vice President of Palatka Operations
Georgia-Pacific, Palatka Mill
P.O. Box 919
Palatka, Florida 32178-0919

Re: Modification of the No. 4 Recovery Boiler, No. 4 Lime Kiln and No. 4 Combination Boiler
Project No. 1070005-038-AC/PSD-FL-380

Dear Mr. Wahoske:

On September 27th, the Department received your response to our request for additional information regarding this project. Based on our review of this information, the application remains incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the items below require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

No. 4 Combination Boiler and No. 5 Power Boiler

1. Describe the methods that will be used to monitor the heat input rate to the No. 4 combination boiler for fuel oil firing and for bark/wood firing (i.e., oil flow meter, steam production rate with thermal efficiency, periodic sampling and analysis of bark/wood, record keeping, etc.).
2. In Attachment E, the particulate matter removal efficiency for the ESP on the No. 5 power boiler is listed as 40-65%. Is this only for particulate matter removal when firing fuel oil? Provide the general specifications for the recently modified ESP for the No. 5 power boiler (i.e., number of fields, T-R sets, acfm, cleaning mechanism, cleaning cycle, etc.)
3. Will the ESP for the No. 5 power boiler be used for the No. 4 combination boiler project? What are the preliminary design parameters for firing bark/wood (inlet loading, outlet loading, removal efficiency, etc.)?
4. If a new ESP will be added for the No. 5 power boiler, provide: the general specifications (i.e., number of fields, T-R sets, acfm, cleaning mechanism, cleaning cycle, inlet loading, outlet loading, removal efficiency, etc.) and the pertinent application pages.
5. Provide the final configuration for controlling particulate matter from the No. 4 combination boiler. If used, will the existing ESP for the No. 5 power boiler be installed parallel to, or in series with, the existing ESP for the No. 4 combination boiler? Will both existing stacks be used? If not, provide the stack configurations.
6. Attachment GP-EU1-I1 is the revised process flow diagram, which clearly shows flue gas recirculation for the No. 4 combination boiler. Is flue gas recirculation currently installed on the No. 4 combination boiler? Will flue gas recirculation be installed on the No. 4 combination boiler for this project? What is the design flue gas recirculation rate (%) and the corresponding NOx reduction?

7. For the similar boilers identified in the response (Camas, Washington and Monticello, Mississippi), provide any available stack test data (CO, NOx, SO_2 and VOC) when firing natural gas with bark/wood and when firing only bark/wood.

8. Please provide the Fuel Tech guarantee for SNCR as well as Georgia-Pacific's request for bid on an SNCR system.

No. 4 Recovery Boiler

9. You provided an additional SO_2 modeling analysis for No. 4 recovery boiler during startup. Provide the rationale for this modeling analysis. Also, verify the hourly emissions rates used in the modeling analyses. It appears that the original "109.9 lb/hour" was used in the analysis of the 24-hour average.

10. In Attachment I, see Table I-6 titled, "SO_2 Class I Impacts in the Okefenokee". The 24-hour second highest values in the table do not match the modeling results submitted. Modeling results (2001) show a 24-hour second highest value of 4.14 ug/m^3 at receptor 5 instead of 3.99 ug/m^3 at receptor 15. Also, modeling results (2003) show a 24-hour second highest value of 2.25 ug/m^3 at receptor 30, instead of 2.16 ug/m^3 at receptor 43. Verify the information and correct as necessary.

Also, representatives from the Bureau of Air Regulation met with representatives from Georgia-Pacific on October 26th. In addition to identifying the above items, we also discussed the following: except for CO emissions, the No. 4 combination boiler project may not result in any increases over baseline emissions; consideration of flexible startup conditions for the No. 4 recovery boiler when firing 100% fuel oil; problems with installing a gas flow meter on the No. 4 recovery boiler due to the proximity of the existing fan and stack; modification of the existing ESP on the No. 5 power boiler; proposed installation of a new ESP for the No. 5 power boiler; and use of the recently modified ESP for the No. 5 power boiler as part of the control system for the No. 4 combination boiler. Some or all of these issues may be addressed in your response to this request for additional information.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information. If you have any questions regarding this request, please call Bruce Mitchell at 850/413-9198 or me at 850/921-9536.

Sincerely,

Jeffery F. Koerner, Air Permitting North Section
Bureau of Air Regulation

JFK/bm

cc: Mr. Keith Wahoske, Georgia-Pacific (keith.wahoske@gapac.com)
Ms. Myra J. Carpenter, Georgia-Pacific (myra.carpenter@gapac.com)
Mr. Mike Curtis, Georgia-Pacific (michael.curtis@gapac.com)
Mr. David Buff, Golder Associates Inc. (dave_buff@golder.com)
Mr. Chris Kirts, NED Office (kirts_c@dep.state.fl.us)
Mr. Gregg Worley, U.S. EPA, Region 4 (worley.gregg@epamail.epa.gov)
Mr. John Bunyak, NPS (john_bunyak@nps.gov)

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

To: U.S. EPA REGION 4
MR. GREGG M. WORLEY
61 FORSYTH STREET
AIR PERMITS SECTION
ATLANTA, GA 30303
UNITED STATES

GND

Pieces: 1/1

ORIGIN: TLH

Sender's ref. 37550201000 A7 AP255

POSTCODE: 30303

TEL: 404-562-9141

Day 22WE

Description: PSD-FL-380 correspondence

Weight: 1 lbs for 1 pcs
Date: 2006-11-21

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Air Permits Section
61 Forsyth Street

Atlanta, GA 30303
UNITED STATES

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

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

Rate Estimate: 3.09
Protection: Not Required
Description: PSD-FL-380 correspondence

Weight (lbs.): 1
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
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Date Printed: 11/21/2006
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EXPRESS

1239 02/04 S

EXP

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111 S MAGNOLIA DR
TALLAHASSEE, FL 32301
UNITED STATES Phone: 850-921-9505

To: NATIONAL PARK SERVICE
MR. JOHN BUNYAK
12795 W. ALAMEDA PARKWAY
AIR DIVISION
LAKEWOOD, CO 80228
UNITED STATES

TEL: 303-966-2818

Pieces: 1/1

ORIGIN: TLH

Sender's ref 37550201000 A7 AP255

POST CODE: 80228

Description: PSD-FL-380 correspondence

Weight: 1 lbs for 1 pcs
Date: 2006-11-21

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Air Division
12795 W. Alameda Parkway

Lakewood, CO 80228
UNITED STATES

Attention To: Mr. John Bunyak
Phone#: 303-966-2818

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

Rate Estimate: 13.54
Protection: Not Required
Description: PSD-FL-380 correspondence

Weight (lbs.): 1
Dimensions: 0 x 0 x 0

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

Special Svc:

Date Printed: 11/21/2006
Bill Shipment To: Sender
Bill To Acct: 778941286

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EXPRESS

1239 02/04 S

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

To: U.S. EPA REGION 4
MR. GREGG M. WORLEY
61 FORSYTH STREET
AIR PERMITS SECTION
ATLANTA, GA 30303
UNITED STATES

GND

Pieces: 1/1

ORIGIN: TLH

Sender's ref 37550201000 A7 AP255

POSTCODE: 30303

TEL: 404-562-9141

Day 05TH

Description: PSD-FL-380 correspondence 9/22/06

Weight: 1 lbs for 1 pcs
Date: 2006-10-04

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SENDER'S RECEIPT
Waybill #: 18153276455

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

Atlanta, GA 30303
UNITED STATES

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

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

Rate Estimate: 3.11
Protection: Not Required
Description: PSD-FL-380 correspondence 9/22/06

Weight (lbs.): 1
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: Ground (Est. delivery in 1 business day(s))

Special Svc:

Date Printed: 10/4/2006
Bill Shipment To: Sender
Bill To Acct: 778941286

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

To: NATIONAL PARK SERVICE
MR. JOHN BUNYAK
12795 W. ALAMEDA PARKWAY
AIR DIVISION
LAKEWOOD, CO 80228
UNITED STATES

EXP+

Pieces: 1/1

ORIGIN: TLH

Sender's ref 37550201000 A7 AP255

POSTCODE: 80228

TEL: 303-966-2818

Time 10:30

Description: PSD-FL-380 correspondence 9/22/06

Weight: 1 lbs for 1 pcs
Date: 2006-10-04

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EGEH 9E

(2L)US80228

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SENDER'S RECEIPT
Waybill #: 18153379753

To(Company):
National Park Service
Air Division
12795 W. Alameda Parkway

Lakewood, CO 80228
UNITED STATES

Attention To: Mr. John Bunyak
Phone#: 303-966-2818

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

Rate Estimate: 13.79
Protection: Not Required
Description: PSD-FL-380 correspondence 9/22/06

Weight (lbs.): 1
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: Next Day 10:30 (Next business day by 10:30 A.M.)

Special Svc:

Date Printed: 10/4/2006
Bill Shipment To: Sender
Bill To Acct: 778941286

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Georgia-Pacific **BEST AVAILABLE COPY**

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

September 22, 2006

Jeffrey F. Koerner, P.E. Permitting North Administrator
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Modification to the Nos. 4 Combination Boiler, Lime Kiln and Recovery Boiler
Project No.: 1070005-038-AC/PSD-FL-380

Dear Mr. Koerner:

On August 18, 2006, GP received a Request for Additional Information (RAI). Our responses to your questions and comments are presented in this letter. In preparing this response, we were very disappointed to find that many of the questions and comments had nothing to do with the permit applications at issue, but instead were asking the Mill to substantiate and defend data and assumptions that were part of past air permitting actions where final permits have long since been issued. This greatly added to the time that it took for us to prepare this response and we are concerned that this action will further delay issuance of our final permit. Furthermore, we strongly believe that data and facts reviewed in prior applications that resulted in a permit being issued should be stipulated as already having been approved by the Department and not subject to further review. Questions No. 1-3 and 5-8 fall into this category.

In order to facilitate planning and scheduling for the 2007 mill outage, GP has asked that the Recovery Boiler / Lime Kiln Projects (fully funded) portions of this application be issued as a separate permit from the No. 4 Combination Boiler Project (unfunded). Our Environmental Attorney, Mr. Scott Matchett recently contacted you to further inquire regarding the Department's ability and predilection to grant this request. GP would like to meet with you very soon to resolve this issue.

For ease of review, we have restated the Department's questions and comments prior to our responses.

<u>**No. 4 Combination Boiler (NO. 4 CB)**</u>

1. In Attachment GP-EU1-F1.8, specifically in Section 1.A., LVHC NCGs, a claim of "at least 60%" sulfur removal efficiency in the pre-scrubber is made. How was this minimum efficiency established? Do you have any performance tests/documentation to support this claim? Please provide any test reports/documentation to support this efficiency removal claim.

This assumption was established during the initial Cluster Rule permitting completed in 2000. It has been used in subsequent permit revisions. In each of these cases, the Department has reviewed and approved this assumption. As such, it is unclear why this issue is being re-visited as part of this permitting action. With that said, the 60% value was a conservative estimate since the pre-scrubber uses white liquor, which is highly alkaline (pH >= 9), and theoretically would remove much higher quantities of sulfur from the non-condensable gas (NCG) stream. We have not found actual test data where the sulfur removal efficiency (*i.e.,* inlet and outlet sulfur concentration in the gas stream) of the pre-scrubber has been measured. As stated several times in the application, the proposed project for the No. 4 CB will in no way affect the manner in which NCG/SOG/DNCG gases are burned in the boiler or the emissions resulting from such burning.

2. In Attachment GP-EU1-F1.8, specifically Sections 1.A, B. and D., provide documentation of the emission factors used, i.e., 378 lbs S/hr loading from the LVHC gas stream, 162 lbs S/hr from the SOG stream and 0.35 lbs S/hr from the DNCG stream, respectively.

These emission factors were established during the initial Cluster Rule permitting completed in 2000/2001, and the Brown Stock Washer permitting in 2004. The LVHC gas stream factors have been used in subsequent permit revisions. In each of these cases, the Department has reviewed and approved the factors. As such, it is unclear why this issue is being re-visited as part of this permitting action. The LVHC gas stream factors were based on a sulfur balance and documented in Table 3-1 of the November 2001 Revised MACT I permit application. The factors for the SOG and DNCG streams are based on NCASI factors and documented in Attachments GP-EU1-G8a & b in the October 2003 MACT 1 BSW/OD project Air permit application. Copies of these tables are in Attachment K.

3. In Attachment GP-EU1-F1.8, specifically Section 2, Maximum 24-hr SO_2 Emission Rate, what is the basis of the 2300 TPD ADUP pulp production rate used in the calculations? Has this level of production ever been achieved? If Not, then identify equipment changes/modifications and/or replacements will have to be made in order to achieve this level of operation?

The 2300 air dried tons of unbleached pulp value was approved by the Department in Air Permit No. 10070005-024-AC and is based on three BSW's achieving a 750 to 770-ton-per-day (TPD) rate (nominal) each. Individually, since start up of the #7 BSW in November 2005, each BSW has been able to wash pulp at a rate of at least 32 air dried tons of unbleached pulp per hour (ADTUP/hour), which if sustained for a full day would result in the mill demonstrating the 2300 TPD value.

Again, it is unclear why this issue is being re-visited as part of this permitting action when these projects have no impact on actual production or capacity. Also, the Department has full documentation on the basis of the 2300 TPD production level from past permitting actions.

4. During a loss of bark feed and a switch to 100% fuel oil firing, do you plan, as a method of operation, to burn the DNCGs, NCGs and SOGs in the No. 4 CB, or will they routed to the No. 5 Power Boiler (No. 5 PB) or some other emissions unit for destruction? Please explain and adjust any calculations that is/are appropriate.

Our plans are to combust the NCG/SOG gases in the Thermal Oxidizer. When the Thermal Oxidizer is unavailable we will combust the gases in the No. 4 CB. The Title V Permit authorizes the combustion in the boiler up to 20% of the time. Likewise, the DNCG gases are currently combusted in the No. 5 PB with the backup as the No. 4 CB. In our view, the combustion time in the Combination Boiler has already been constrained when burning the NCG/SOG gases. No further benefit is provided by limiting which boiler will burn the DNCGs because the boiler stacks are the same height and located adjacent to each other. Also, the sulfur dioxide emission calculations in the application reflect the worst-case condition of 100% fuel oil and burning the total reduced sulfur (TRS) gases in the No. 4 CB for up to 20% of the time.

As stated several times in the application, the proposed project for the No. 4 CB will in no way affect the manner in which NCG/SOG/DNCG gases are burned in the boiler, or the emissions resulting from such burning. This was clearly stated in our application. We do not believe that any adjustments in the calculations are needed as part of the permitting action.

5. For the annual SO_2 emissions calculations in Attachment GP-EU1-F1.8, what is the basis for the "20% utilization of the No. 4 CB for the destruction of NCGs, SOGs and DNCGs"? Please explain and provide justification. Adjust any calculations that is/are appropriate. When in this mode, how are you demonstrating compliance with the TRS limit?

This operational scenario was established during the initial Cluster Rule permitting completed in 2000. It has been used in subsequent permit revisions. In each of these cases, the Department has reviewed and approved the scenario. It is based on the assumption that the No. 4 CB, as a worst-case operating scenario, would be utilized as a backup destruction device 20% of the time on an annual basis.

As stated in Condition C.12 of the current Title V operating permit (Permit No. 1070005-034-AV), compliance with the TRS limit of 5 ppmvd at 10% oxygen is achieved by maintaining the minimum temperature of 1,200°F and 0.5 second residence time. Documentation that these requirements were being met was submitted to the Department in a report from Mr. David Buff to Ms. Rita Felton-Smith dated June 30, 2004 in conjunction with the application process for Permit No. 1070005-024-AC. A copy of that report is included in Attachment A.

Again, it is unclear why this issue is being re-visited as part of this permitting action when these projects do not affect the manner in which NCG/SOG/DNCG gases are burned in the boiler or the emissions resulting from such burning. This was clearly stated in our application.

6. Is the thermal oxidizer, which is the primary destruction device for NCGs and SOGs, down 20% of the operational year? If so, please explain. In addition, provide the hours of operation and downtime for the thermal oxidizer for the last five years.

No, the Thermal Oxidizer (TO) has not been down 20% of the time over the past four years. As the primary destruction device for NCG/SOG gases, the TO has been used to burn NCG/SOG gases about 85-90% of the time. As the Department is aware, the Thermal Oxidizer did not operate the first four months of 2002. It was started up in May 2002. The hours of operation of the Thermal Oxidizer (which includes times when the TO was burning natural gas and NCGs were being burned in the No. 4 CB) are as follows:

2002 - 5,720 hours, 2003 – 8,547 hours, 2004 – 7,772 hours, 2005 – 8,687 hours

While not specifically tracked on a daily basis, the downtime hours for the Thermal Oxidizer are estimated as follows:

2002 - <1,000 hours (from 4/16/02 to 12/31/02), 2003 - 213 hours, 2004 – 1,012 hours, 2005 - 75 hours

Again, it is unclear why this issue is being re-visited as part of this permitting action when these projects do not affect the manner in which NCG/SOG/DNCG gases are burned or the emissions resulting from such burning. This was clearly stated in our application.

7. While the thermal oxidizer is operating, have you ever routed the NCGs and SOGs to the No. 4 CB or another emissions unit for destruction? If yes, please explain.

Yes, to better control the flame in the TO while doing adjustments we sometimes simultaneously burn NCGs in the TO and the SOGs in the No. 4 CB. The NCG or SOG gases are sent to the combination boiler any time we need to work on the TO flame scanners, instrumentation, or other for other maintenance needs. While these maintenance activities are taking place, we have burned only NCGs or only SOGs in the Thermal Oxidizer and the other gas stream in the No. 4 CB. However, this is done on a limited time basis and operation in this manner is allowed by our construction and TV permits.

It is unclear why this issue is being re-visited as part of this permitting action when these projects do not affect the manner in which NCG/SOG/DNCG gases are burned, or the emissions resulting from such burning. This was clearly stated in our application.

8. When the No. 4 CB is used as a backup control device for NCGs, SOGs, and DNCGs, how is compliance demonstrated? For the years that the No. 4 CB has been used as a backup control device for the thermal incineration system, provide the number of hours of operation in this backup control mode and the percent of total operation of the No. 4 CB in this backup control mode. Is the No. 4 CB also the primary control device for DNCGs (see Page 2-8)? When the No. 4 CB is used as the control device for NCGs, SOGs, and DNCGs, do the controlled emission levels comply with the NESHAP, 40 CFR 63, Subpart S?

It is very surprising that the Department is even asking this question, as the monitoring requirements, which are consistent with the Cluster Rule, are clearly spelled out in Condition C.12 of the current Title V operating permit (permit No. 1070005-034-AV), which recognizes that compliance with the TRS limit of 5 ppmvd @ 10% oxygen is achieved by maintaining the minimum temperature of 1,200^{o}F and 0.5 second residence time. The compliance demonstration method is documentation that these requirements were being met and proper documentation was submitted to the Department as stated in our response to Question 5 of this RAI.

The use of the No. 4 CB to burn NCG/SOG/DNCGs is documented in annual reports to DEP. The time that the No. 4 CB was operating, was used as a backup device to the Thermal Oxidizer to burn NCG/SOG gases, and the percent of total operating time that NCG/SOG gases were burned in the No. 4 CB are as follows:

The No. 4 CB was in operation as follows:
2002 – 5,949 hours (2,3 & 4Q's), 2003 – 8,302 hours, 2004 – 8,425 hours, 2005 – 8,323 hours

The No. 4 CB was used to burn NCG/SOG gases as follows:
2002 – 1,120 hours (18.8% of the time), 2003 – 1,286 hours (15.5% of the time),
2004 – 1,341 hours (15.9% of the time), 2005 – 1,007 hours (12.1% of the time),

Note – The old TRS incinerator was used until April 2002.

It is unclear why this issue is being re-visited as part of this permitting action when these projects do not affect the manner in which NCG/SOG/DNCG gases are burned.

9. Based on the exceptions listed in the PSD Report, Section 2.3.1., Past Actual Emissions, have you submitted a correction to the 2004 and 2005 AORs?

This is actively being worked on and updates will be sent to DEP by September 29, 2006. Based on the updates to the AOR, updates have been made to Tables 2-1, 2-3, and 3-3 of the No. 4 CB PSD Application. The changes are minor in nature and do not affect any conclusions stated in the PSD report. The revised tables are included in Attachment L.

10. The Bark Hog project used a heating value for wet as-fired bark of 4500 Btu/lb. Yet for this project, the value of 4750 Btu/lb, wet and as-fired is being used. The permitted capacity of Btu/hr heat input to the No. 4 CB was limited to 512.7 MMBtu/hr, based on "57 tons per hour carbonaceous fuel (bark/wood chips) with an average heating value of 4500 Btu/lb on a wet, as-fired basis". In this application, the requested heat input is 564 MMBtu/hr based on "59.4 TPH tons per hour carbonaceous fuel (bark/wood chips) with an average heating value of 4750 Btu/lb on a wet, as-fired basis". Please explain why you used a different heating value for the same material. Also, resubmit corrected pages as appropriate.

The 4750 btu/lb value most closely represents the heating value of bark/wood being burned in the No. 4 CB. The 4750 btu/lb value is the result of testing in 2003/2004 and is used in the mill for heat input calculations. This value is currently being used to calculate heat inputs during compliance stack testing and during daily operations.

11. According to the application, the current permitted maximum heat input rate to the No. 4 CB is 512.7 MMBtu/hour based on a 24-hour average. Based on a wood/bark heating value of 4750, this is equivalent to a maximum of 54 TPH and 1296 TPD of wood/bark firing. The application requests a maximum annual heat input rate of *4,042,127 MMBtu during any* consecutive 12 months. The proposed physical changes (upgraded bark/wood delivery system, new air swept bark/wood feeders, new OFA system and modified combustion air supply, modified under fire air distribution, upgraded ash removal system, etc.) will allow the existing No. 4 CB to achieve the above maximum heat input rates and wood/bark firing rates. Is this accurate?

The maximum annual heat input rate is correct as requested. The No. 4 CB can already achieve the maximum hourly and 24-hour heat input rates, as demonstrated by historic steam rate records, based on firing a combination of bark/wood and fuel oil. As described in the application, the proposed changes will only allow more bark/wood to be burned on a short-term and annual basis, thereby reducing the need for fuel oil.

12. For CO, NOx, SO_2, and VOC emissions: provide any emissions test data available for the No. 4 CB; and, provide any emission test data available for other G-P boilers similar to the No. 4 CB at the Palatka Mill.

The Palatka Mill has performed some limited stack testing for NO_x and SO_2. A summary of the data is in Attachment B. We have not collected any data for CO or VOC emissions.

GP owns two combination boilers other than the one at the Palatka Mill that are similar in design in that they use a traveling stoker grate to burn "hog" fuel in addition to burning supplemental fossil fuel. One of these boilers is located at GP's Camas, Washington Mill and the other boiler is located at GP's Monticello, Mississippi Mill. However, both of these boilers burn natural gas as the supplemental fuel in addition to hog fuel, and not No. 6 fuel oil as is the case for the boiler at the Palatka Mill. For this reason, GP does not have any emissions test data from other boilers that can be compared to the unit at the Palatka Mill.

13. See Attachment GP-EU1-I1, which is a process flow diagram for the No. 4 CB.

a. This chart shows ash from the new mechanical dust collector being directed back to the NO. 4 CB and not the ash sluice tanks. Please explain.

Ash from the dust collectors and precipitators will be sluiced. An updated Process Flow Diagram is included in Attachment C.

b. This chart shows the exhaust from the No. 4 CB directed to the new mechanical dust collector and then being split between the existing ESP for the No. 4 CB and the existing ESP for the No. 5 PB. The application later indicates that the ESPs for the No. 4 CB and the No. 5 PB will be refurbished the ESP for the No. 5 PB may be used as the 4^{th}, 5^{th} and 6^{th} fields for the exhaust from the No. 4 CB. If this happens, a new ESP will be installed for the No. 5 PB. In other words, the exhaust streams will never mix and there will only be one stack. Is this accurate? Provide additional details of the proposed configuration, cost of the proposed ESP work for the No. 4 CB, cost of the proposed ESP work for the No. 5 PB (including new field), cost of the connecting ductwork, and the cost of a proposed new ESP for the No. 5 PB.

The exhaust gases from the No. 5 PB will never mix with the exhaust gases from the No. 4 CB. While the exact configuration has not been finalized it is currently thought that the No. 5 PB stack would be used for the No.5 PB and the existing No. 4 CB stack will be used for the No. 4 CB. The appropriate duct work would be installed to make this happen.

It is still possible that a new stack will be installed with a new precipitator for the No. 5 PB. In that case the two existing precipitators and stacks would be used for the No. 4 CB. Specific cost data is not available at this time because exact arrangement for the No. 4 CB has not been finalized. The plans will be finalized during detailed design engineering. While final funding approval has not yet occurred we have estimated that over $2.5 million will be spent on the No. 4 CB ESP.

c. The Department is aware the G-P has filed a separate minor source air construction permit with the NED Office to install a new field on the No. 5 PB. The system is being designed for a much larger flue gas flow rate than is needed for the No. 5 PB. Has G-P made the decision to use the refurbished ESP for the No. 5 PB to control emissions from the No. 4 CB? Isn't this project related to the PSD application for the No. 4 CB? Please explain.

As stated in the application for the No. 5 PB ESP upgrade, the purpose of the upgrade is primarily to improve reliability of the ESP to meet the PM emission limits for the No. 5 PB at various operating loads in the event that the No. 4 CB upgrade project is not funded. This project is not related to the No. 4 CB project in any way. The design flue gas flow rate shown in the application of 455,000 actual cubic feet per minute (acfm) is an error and should be shown as 230,000 acfm (the original design value that is not being changed). An updated table (GP-EU1-I3) from the No. 5 PB precipitator construction permit application is included in Attachment D. This updated table is being sent to the DEP Jacksonville Air office as well.

The new field in the precipitator for the No. 5 PB is designed to offer better collection efficiency on that unit under current operating conditions, and to provide operational flexibility in the case of equipment downtime on one field.

A final decision on how the No. 4 CB ESP field design will be augmented has not been made. The use of the No. 5 PB ESP in series, and following the No. 4 CB ESP is just one of the options being considered. Other options include increasing the size of the chambers or adding just one new chamber.

14. See Attachment GP-EU1-I3, which provides control equipment details for the No. 4 CB.

o Details for the new mechanical dust collector indicate a maximum inlet flow rate of 280,000 acfm @ 700° F.

o Details for the refurbished ESP for the No. 4 CB indicate a maximum inlet flow rate of 455,000 acfm @ 325° F.

a. Is additional air being provided to cool the exhaust prior to the ESP?

As discussed in our response to Question 13c, the correct design air flow for the ESP is 230,000 acfm. No cooling air or dilution air is provided prior to the ESP.

b. Identify the dscfm of exhaust from the NO. 4 CB, the dscfm of cooling air, and the total dscfm to the ESP.

The dscfm of exhaust from the NO. 4 CB is shown on page 17 of the emissions unit section of the application form – 135,400 dscfm @ 10% O_2. The typical oxygen content of the gas stream is 5%, which would result in an exhaust flow rate of 93,088 dscfm.

c. What is the design temperature for the ESP?

The actual design temperature for the ESP is 450°F. Attachment GP-EU1-I3 of the application form has been updated – see Attachment E.

d. Are new fans being installed to achieve this cooling and exhaust rate?

No. See answer to 14.a.

15. Why weren't past actual PM emissions simply based on previous stack test data? Does the boiler typically fire oil with wood/bark? At what rate? Are assumed control efficiencies reasonable based on the existing cyclone/ESP control system installed for this unit?

As described on page 2-5 of the PSD Report, actual stack tests were used to estimate past actual PM emissions. Since the stack tests allowed the development of emissions due to wood/bark and No. 6 fuel oil individually (see Table 5-4), these factors were applied to the annual fuel usage amounts for each individual fuel.

Currently, the boiler typically does fire some oil with wood/bark. Generally, about 400-600 gal/hr oil is fired with the maximum amount of wood that can be fired. As described in the application, the purpose of the proposed project is to increase the amount of wood/bark that can be fired and to decrease the fuel oil firing.

The assumed control efficiency is reasonable based on some test work on the inlet to the precipitator that indicates greater than 95% control efficiency for the existing No. 4 CB ESP. However, please note that past actual PM emissions from the No. 4 CB were not based on control efficiency of the ESP but rather the emission factors described in Table 5-4 of the PSD Report.

16. The application indicates that the current PM standard is 0.3 lb/MMBtu and requests a BACT limit of 0.04 lb/MMBtu. NESHAP DDDDD provisions establish a PM standard of 0.025 lb/MMBtu for new solid fuel-fired boilers. Table 5-1 of the application lists the PM/PM_{10} BACT determination for 34 recent projects for biomass-fired boilers. Of these, 17 projects have BACT determinations of 0.03 lb/MMBtu or less. Explain why the additional improvements described for the ESP(s) would not be able to achieve such a level of emissions for the No. 4 CB.

The No. 4 CB is not a new boiler, nor does it have new control equipment. Upgrades are being proposed to improve both combustion and control efficiency. However, an existing boiler cannot be expected to meet the emission levels of a completely new, modern boiler with a new ESP. New boilers have much greater furnace volumes to maximize combustion efficiency, minimize unburned carbon, and minimize the heat lost out the stack. The furnace volume of the No. 4 CB cannot be increased at this point in time, so there are limitations on what can be done to improve performance. Likewise, the existing ESP can only be improved to the extent possible based on the existing design and configuration. It cannot be modified to operate like a new ESP. That would require completely replacing the ESP.

The NESHAP DDDDD establishes a PM limit for *existing* boilers of 0.07 lb/MMBtu. The proposed BACT limit of 0.04 lb/MMBtu is closer to the limit for new boilers than it is to the limit for existing boilers. Since GP is proposing a not-to-exceed limit of 0.04 lb/MMBtu, actual PM emissions from the boiler will need to be lower in actual operation in order to maintain a margin of compliance..

17. The application indicates that new low-NOx burners (LNBs) will be installed to fire No. 6 fuel oil (2.35% sulfur content, by weight, max.). These burners will replace the same number of existing oil burners, will have the same heat input rate, will achieve a NOx emission standard of 0.27 lb/MMBtu, and will be restricted to firing no more than 5,100,000 gallons during any consecutive 12 months. The application also indicates that there are 6 oil guns. How many total oil burners are there? What is the generally acceptable range of NOx emissions for a burner to be considered a "low-NOx" burner? Provide the vendor specifications for both the CO and NOx emissions from the proposed new burners. Please explain the use of the "0.164" factor when estimating SO_2 emissions from oil firing. Is this a reasonable estimate of SO_2 emission from oil firing?

In the application, "oil gun" is synonymous with "oil burner". Low-NO_x burners for No. 6 fuel oil generally provide only a small amount of NO_x reduction due to the nature of the No. 6 fuel oil and the fuel bound nitrogen. Generally a 10%-15% reduction in NO_x from existing levels would classify the burner as low-NO_x.

We do not have a vendor specification for emissions from a low-NOx burner while burning No. 6 fuel oil. The proposed emission limit for NO_x is based on discussions with the vendor and an estimated 15% reduction from the uncontrolled emission rate of 0.31 lb/MMBtu.

The "0.164" factor was actually required by the Department in the previous permitting of the No. 4 CB. It is based on a stoichiometric calculation of the sulfur in the fuel converting to SO_2:

$$8.2 \text{ lbs/gal} \times (\%S/100) \text{ lb S/lb oil} * 64 \text{ lb } SO_2\text{/lb-mole} \div 32 \text{ lb S/lb-mole} \times \text{lb mole } SO_2\text{/lb-mole S} =$$

$$0.164 \ * \ \%S \ \text{ lb } SO_2 / \text{gal oil}$$

where: %S is the percent sulfur in the fuel,

This equation may overestimate the actual SO_2 emitted since some sulfur will be converted to SO_3 or SO_4 in the stack and will not exit the stack as SO_2.

It is unclear why this issue is being re-visited as part of this permitting action when it has been addressed as part of prior permitting actions.

18. Describe the new equipment, controls, and improvements to the over fire air (OFA) system for the No. 4 CB. Has (or will) computational fluid dynamic modeling be conducted to aid in the design of the OFA? Provide any vendor specifications available regarding emission levels before and after installation of the new OFA.

If needed, Computational Fluid Dynamic (CFD) modeling will be conducted during the design phase of this project depending upon the vendor selected and that vendor's design needs. More refined emission level estimates would be available as a result of this modeling.

Although final engineering has not been performed, the system would generally consist of the following components: new over fire air nozzles; dampers with automatic drives; ductwork; pressure, temperature and air flow monitors and transmitters; new fuel distributors; and O&M manuals. One vendor has guaranteed a NO_x emission level of 0.24 lb/MMBtu, while another has guaranteed 0.25 lb/MMBtu following the installation of the new OFA system.

19. Does the No. 4 CB currently have flue gas recirculation (FGR)? What is the maximum designed percent of FGR? Does the boiler operate at this rate? When was it installed?

This unit is not equipped with an FGR system.

20. As stated in the application, SNCR for several Florida biomass-fired boilers have achieved levels of up to 50% NOx reduction. Provide a revised cost effectiveness analysis assuming this level of control. Provide details for this specific boiler that causes problems related to an SNCR system and high control efficiencies

Due to the existing boiler design and associated constraints, the SNCR vendor (FuelTech) will not guarantee a NOx reduction of greater than 35% for bark/oil and 25% for oil alone. The constraints that affect the vendor guarantee include: combustion byproducts, upper furnace flue gas temperature, flue gas velocity and residence time available to the SNCR process, furnace access for reagent distribution purposes, flue gas temperature at the outlet of the air preheater, and the amount of ammonia slip that can be tolerated.

21. Page 3-12 of the application states that NSPS Subpart Db could apply to the project to modify an oil and wood-fired boiler if there was an hourly increase in emissions. The conclusion is that this subpart does not apply because PM emissions will actually decrease for this unit. Provide a similar discussion for SO_2 and NOx emissions, which are also regulated by this subpart. Please correlate the discussion with that provided on Page 3-13 regarding SO_2 and NOx emissions.

As stated in the application, the project includes replacing the existing No. 6 fuel oil burners with oil burners of the same number and capacity. As such, the fuel oil burning potential of the boiler is not increasing. Therefore, SO_2 emissions will not increase on an hourly basis for fuel oil firing. Since hourly SO_2 emissions due to fuel oil firing will not increase, and there is no SO_2 emission standard in the NSPS for wood firing, the NSPS will not be triggered for SO_2.

Likewise, for NO_x, the fuel oil burning potential of the boiler is not increasing, and the low-NO_x burners will result in a reduction in maximum hourly NO_x emissions due to fuel oil firing. Since hourly NO_x emissions due to fuel oil firing will not increase, and there is no NO_x emission standard in the NSPS for wood firing, the NSPS will not be triggered for NO_x.

22. Is the existing No. 4 Power Boiler currently shutdown? What is the date of last operation for this unit? Is this unit currently able to operate in its current condition? When will construction begin on the proposed PSD project?

The No. 4 PB is shutdown. It last operated in September 2003. The unit could not operate in its current condition. The shutdown of this unit is documented in Section 2.2 of the PSD Report. Construction on the proposed PSD Project should commence in late March to early April 2007.

23. In the section labeled "PSD Report", specifically page 2-7, next-to-last paragraph, you indicated that the No. 5 PB's modified ESP "may" be used by the No. 4 CB's operation for additional control of particulate emissions. Based on this, please respond to the following issues:

a. Please describe what "may" means.

"May" means plans are not yet final. In the event that the CB Upgrade Project is funded, the No. 5 PB ESP may be used as a final PM control device in conjunction with (in series or in parallel) the existing No. 4 CB ESP. Also note that we are not stating that both the No. 4 CB and the No. 5 PB will be controlled by the existing No. 5 PB ESP. In fact the stack gases from the individual boilers will not be combined in any fashion.

If the No. 5 PB ESP is used as a control device for No. 4 CB, then current plans call for the No. 5 PB to have a new ESP installed to control its emissions (see pg. 1-1 of PSD Report). This was addressed in our response to Question 13 above.

b. Are you planning to use the No. 5 PB's modified ESP to control particulate emissions from the No. 4 CB's operation on a permanent basis? If Not, please explain.

If the No. 4 CB stack gases are routed to the existing No. 5 PB ESP, it will be on a permanent basis. We are currently exploring whether the existing ESPs would be utilized in parallel or in series once they are servicing the No. 4 CB.

c. Which stack will be used on a permanent basis...the No. 4 CB's or the No. 5 PB's....when the No. 5 PB's modified ESP is being utilized?

Both stacks will be used on a permanent basis. It is expected that the No. 4 CB stack will continue to service the No. 4 CB and the No. 5 PB stack will continue to service the No. 5 PB. As discussed in several answers above and in the application, the configuration has not yet been finalized.

d. Since the No. 5 PB and its mass emissions will be impacted by the No. 4 CB project, have the emissions of all affected pollutants been included in the modeling for the No. 4 CB project, which includes the Nos. 4 RB and LK projects? Did you assess the potential impact of all of the pollutant emissions exiting the No. 5 PB's modified ESP and its associated stack?

The No. 5 PB operation or emissions are not being impacted in any manner except that the No. 5 PB ESP may be used as additional fields to augment the No. 4 CB ESP. The No. 5 PB ESP would be upgraded in the event that the No. 4 CB Upgrade project is funded. As stated in our response to Questions 13 and 23 b above, we are stilling exploring the exact configuration of the flows through the ESPs.

We expect that this would only have the effect of lowering PM emissions from the No. 5 PB. The No. 5 PB, itself, will not be modified in any way as part of the proposed project.

e. What is the resultant flue gas volumetric flow rate in "dscfm @ 10% O_2" when the No. 5 PB's modified ESP is being utilized by the No. 4 CB's operation?

Since the flow rate is dictated by the No. 4 CB (boiler), and not the ESP (regardless of which ESP is used), the flow rate shown on page 17 of the application for the No. 4 CB, 278,400 acfm, is valid for this scenario as well. The gas flow rate is 135,000 dscfm @ 10% O_2.

f. List and describe all of the "methods of operation" for which the No. 5 PB's modified ESP will be used by the NO. 4 CB's operation, and this listing should include all of the fuels (100% fuel oil to percentages of fuel oil and bark) used by the No. 5 PB and the No. 4 CB.

This question implies that two boilers will be routed to a single ESP. This will not be the case. Under the scenarios described above, No. 4 CB and No. 5 PB will continue to have separate, dedicated ESPs.

g. Regarding the No. 5 PB's modified ESP as an extended control device of the No. 4 CB's operation, what is the expected control efficiency for each pollutant? Provide all assumptions and calculations.

The ESP will only control PM emissions (and therefore metals and sulfuric acid mist). For the scenario where the No. 5 PB ESP acts as the second "3-field chamber" for the No. 4 CB, the PM control efficiency is difficult to determine, as much of the PM will have been removed in the first 3-field chamber (existing No. 4 CB ESP). Since the exact configuration of the flows through the ESPs has not yet been determined, we do not have estimates for each pollutant.

h. Will the pollutant emissions of the No. 5 PB's modified ESP increase due to this project?

No – that is not expected. We expect lower emissions. If a new ESP is installed for the No. 5 PB, more current technology would dictate that the unit perform, at or above, the efficiency of the existing ESP. See responses a.-f. above. We are not modifying the No. 5 PB ESP as part of this project. When exhaust gases from the No. 4 CB pass through the existing No. 5 PB ESP the discharge PM will have to meet the limit proposed in this application – 0.04 lbs/MMBTU.

i. Will the inlet loading to the No. 5 PB's modified ESP increase due to this project?

This depends on the exact configuration of the revised ducting that will be used to direct flows to the ESP's. As stated previously, the No. 5 PB ESP could act as the second "3-field chamber" (in series) behind the No. 4 CB ESP's existing "3-field chamber". In this mode the inlet loading to the No. 5 PB ESP would be lower. If the two ESPs are operated in parallel, the inlet loading (in gr/dscf) to the No. 5 PB ESP would be expected to increase. In either case the resulting stack discharge would still meet the PM limits stated in this application.

j. Will there be an increase in the flue gas volumetric flow rate through the No. 5 PB's modified ESP due to this project? If so, please provide the assumptions and calculations for the potential pollutant emissions due to this increase in flow rate.

As described above this depends on the exact configuration of the revised ducting that will be used to direct flows to the ESPs. As stated previously, the No. 5 PB ESP could act as the second "3-field chamber" (in series) behind the No. 4 CB ESPs existing "3-field chamber". In this mode the flue gas volumetric flow rate would be the higher rate of the No. 4 CB.

If the two ESPs are operated in parallel, the flue gas volumetric flow rate to the No. 5 PB ESP would be expected to decrease.

In either case the resulting stack discharge would still meet the PM limits stated in this application.

k. For the No. 5 PB, what is the volumetric flow rate of the modified ESP in "dscfm @ 10%O_2"? Based on the RAI response letter to the Northeast District dated June 29, 2006, regarding an application to modify the No. 5 PB's existing ESP, the design flow rate for the No. 5 PB's modified ESP was stated as 455,000 acfm. Since the original design flow rate was 231,500 acfm, and your response in Response #3 was that there will be no change to the existing ESP's fans, ducts, etc., then please explain how the modified ESP's flow rate will be 455,000 acfm without some fan and/or physical modification? Please provide any assumptions and calculations.

As stated in our answers to Questions 13c and 14a, the 455,000 acfm value is incorrect. When utilizing the No. 5 PB ESP for the No. 4 CB emissions, the flow rate will be that of the No. 4 CB, 135,400 dscfm @ 10% O_2, as shown in the application form for the No. 4 CB. The original design flow rate for the No. 5 ESP was 230,000 acfm. This has not changed.

l. Since the No. 4 CB's TRS allowable limit is 5 ppmvd @ 10% O_2, the current potential mass emissions of 3.6 lbs/hr and 15.7 TPY are based on a volumetric flow rate of 135,400 dscfm. Unless the No. 5 PB's volumetric flow rate, in "dscfm @ 10% O_2", is the same as the existing No. 4 CB's dscfm flow rate, then the potential mass emissions of TRS will be increased when utilizing the No. 5 PB's modified ESP and appears to implicate that the net TRS mass emissions will be greater than significant and, therefore, subject to PSD NSR preconstruction review and BACT. If so, please submit the appropriate material and determination related to this.

The utilization of the No. 5 PB ESP has nothing to do with the allowable TRS emission from No. 4 CB. TRS is controlled by combustion and is not controlled by the ESP. The allowable emissions are based on the actual dscfm from the No. 4 CB.

m. In the PCP project for the burning of SOGs, NCGs and DNCGs, were the resultant SO_2 emissions evaluated exiting the Thermal Oxidizer and its backup, the No. 4 CB? Based on the current proposal, this evaluation should be conducted if the No. 5 PB's modified ESP is going to be utilized by the No. 4 CB's operations and SOGs, NCGs and DNCGs are being incinerated in the No. 4 CB. If this was Not done, please do so to provide reasonable assurance that there is no NAAQS Nor increment violations.

Yes, both cases were evaluated. As far as impacts on modeling results, the previous modeling is considered adequate since the No. 4 CB and No. 5 PB stacks are located adjacent to each other (within 25 feet), and both have the same stack height and diameter (*i.e.*, the stacks are identical).

n. It appears that the No. 5 PB's ESP modification and the recent application submittal for modifications to the Nos. 4 CB, RB and LK are related, i.e., the No. 5 PB's modified ESP will become a particulate control device for the No. 4 CB's operation. As such, why wasn't the No. 5 PB's ESP modification and any appropriate changes, including impacts, modeling and potentially BACT, included in this project?

This question was asked and answered in our response to Question 13c. As such, it is unclear why this question is being asked a second time. As stated previously, the No. 5 PB ESP "may" be used as a second "three field chamber" for the No. 4 CB. This decision has not been finalized. In this case, emissions from the No. 5 PB will not be affected, except that its new ESP should be more efficient with lower PM emissions.

24. In the netting table, why did you not include any past and future TRS mass emissions from the No. 4 CB, since it is the back-up control device for SOGs and NCGs and the primary control device for DNCGs, and it has an allowable emissions limit of 5 ppmvd @ 10% O_2? It should at least include the "20% utilization factor" requested and depicted in Attachment GP-EU1-F1.8. Was the No. 4 CB used during CY 2004 and 2005 for the incineration of these gases? Provide the dates and amount of time it was utilized for this purpose during these years and make the calculations and appropriate adjustments to the netting table, Table 1, Past Actuals. Also, see Issue No. 5, above.

The exclusion of the emissions from No. 4 CB due to incineration of TRS/HAP gases was explained at length on pages 2-7 and 2-8 of the PSD Report. The incineration of these gases will not be affected by the proposed No. 4 CB project. The burning of NCG/SOG gases in the No. 4 CB is addressed in our response to Question 8.

25. In the application, Section H. Continuous Monitor Information, there was no pages completed, yet the requirements for continuous emissions monitoring of TRS emissions pursuant to Rule 62-296.404(3)(f) and (5)(c), F.A.C., are applicable. Have you installed the devices to continuously monitor temperature at the point of combustion and oxygen pursuant to the requirements? If not, please explain. If so, please complete the appropriate application pages and submit.

Pursuant to 62.296404(3)(a), NCGs from the digesters, MEE system, and condensate stripper are to be "collected and incinerated in a lime kiln or calciner…or kraft recovery furnace…, or a combustion device." Note that the term incineration is used to describe the process of combustion

rather than referencing combustion in a particular device. Section 404(3)(f) essentially defines "other combustion devices" as power boilers, carbonaceous fuel burning equipment and incinerators. In our case, these gases are collected and incinerated in the Combination Boiler, a carbonaceous fuel burning device. Because the Department defined power boilers and carbonaceous fuel burning equipment separately from an incinerator, the requirement to install equipment to monitor temperature in 296.404(5)(c) does not apply. There is also no requirement that the Combination Boiler be equipped with a TRS CEMS because the control technology employed is incineration (see 296.404(5)(a)).

As discussed in our response to Question 5, the Cluster Rule requirements were satisfied by demonstrating that the TRS gases will experience a 1,200°F temperature for at least 0.5 second.

As is the case with so many other questions in this document, this question has no relevance to the application at hand. The monitoring requirements were all addressed, and permitted, as part of our past Cluster Rule compliance projects. As discussed in detail in our application, the proposed project for the No. 4 CB will not affect the manner in which NCG/SOG/DNCG gases are burned in the boiler or the emissions resulting from such burning.

26. In Attachment GP-EU1-I3, Detailed Description of Control Equipment, specifically for the No. 5 PB's ESP, the control efficiency is listed as 99.5% for particulate matter. Is this accurate? If not, please explain, correct and resubmit the document.

No the control efficiency value was updated in the RAI response on the No. 5 PB ESP Third Field project (Permit No. 1070005-036-AC). The updated design information table for the No. 5 PB is included in Attachment D.

27. Please identify any other emissions units/activities that will be affected upstream and downstream by the increase in production and steam output due to the proposed modification of the No. 4 CB. If any, please include in the analysis any increases in production and associated pollutant emissions, including any collateral emission changes and increases (NCG's TRS to SO_2, etc.) for these emissions units/activities.

Because there is no increase in heat input or steam output (production) there are no other emissions units or activities affected either upstream or downstream. The project does describe the increase in bark throughput with a coincidental reduction in oil consumption. The Bark Hog project (Permit No. 1070005-028-AC/PSD-FL-341) was originally part of the overall No. 4 CB upgrade project but, as you are aware, we were directed by the Department to break these into two separate projects. We were later directed by the Department to re-combine them, and also consider other non-related projects, as part of an overall NSR applicability analysis. The Bark Hog permit was issued on January 5, 2005.

As discussed in detail in numerous places in our application, the proposed project for the No. 4 CB will in no way affect the manner in which NCG/SOG/DNCG gases are burned.

No. 4 Lime Kiln (LK).

28. For the LK, provide the actual venturi scrubber pressure differential for each of the particulate matter emissions tests provided with the application (1995 – 2005).

The values are as follows:

1995 – 27", 1996 – 27", 1997 – 28", 1998- 28", 1999 – 28",
2000 – 28", 2001 - 28", 2002 – 28", 2003 – 28", 03/2004 – 27", 08/2004 – 26", 2005 – 26".

29. The proposed BACT emissions standards in Table E-7 do not reflect the proposed BACT standards in the DEP application form Nor the annual emissions used in the netting analysis. Please revise accordingly.

The revised Table E-7 is in Attachment F.

No. 4 Recovery Boiler (RB).

30. For the RB, the application proposes the following CO limits: 800 ppmvd @ 8% oxygen (3-hour average) and 400 ppmvd @ 8% oxygen (24-hour average). The application also reflects G-P's agreement to install a CO CEMS. Please verify the averaging periods.

As previously agreed upon with the Department in discussions surrounding PSD-FL-367, Georgia-Pacific intends to install a CO CEMS on the Recovery Boiler outlet stack. We are committed to meeting the limits proposed in the latest RB draft permit that was sent to GP on May 26, 2006, namely: a 30-day rolling average of 800 ppm at 8% O_2 for the first 180 days after initial certification of the CO CEMS; and a 30-day rolling average of 400 ppm at 8% O_2 following the initial 180-day period.

31. For the RB, provide a discussion on the fraction of PM_{10} emissions of the PM emissions. This appears different than previous submittals.

The factor used was 75% of PM emissions and is the same factor used in the November 2005 RB PSD application. This factor comes from AP-42, Table 10.2-3, for recovery boilers without a direct contact evaporator, but with an ESP. The table shows that 74.8% of controlled PM is less than or equal to 10 microns.

Nos. 4 LK, RB and Smelt Dissolving Tank.

32. For all applicable units, please verify that past actual emissions for TRS and SO_2 were based on CEMS data and not test data. Please revise the calculation pages and the netting table appropriately.

The LK and the RB both have CEMS for TRS. However, there is no continuous gas flow rate measurement on which to base a calculation of annual emissions. Therefore, the stack test data and the operating hours are considered most representative for the calculation of past actual emissions.

Miscellaneous.

33. Where is the No. 5 PB located on the facility plot plan?

On the facility plot plans included in the applications, the No. 5 Power Boiler is referred to as the No. 5 Combo Boiler. This is not correct and the plot plan has been revised. A mill plot plan is included in Attachment G and the No. 5 PB is highlighted.

The No. 5 PB is located in the powerhouse structure adjacent to, and due east of, the No. 4 Recovery Boiler building. Both the No. 5 PB and No. 4 CB are housed in the powerhouse building with the No. 5 PB on the north side and the No. 4 CB on the south side. The stacks for the boilers are located on the south side of the structure with the No. 5 PB stack being on the west side and the No. 4 CB stack on the east side.

34. Due to the recent changes made regarding the Primary Responsible Official and Authorized Representative at the Georgia-Pacific's Palatka Mill, please have Mr. Wahoske sign, date and submit a completed application's "Owner/Authorized Representative Statement" page for each of the submitted applications, one for the No. 4 CB and one for the combined LK and RB.

We will submit these, because it is not unduly burdensome to do so, but the request strikes us as unnecessary. Mr. Kennedy was the Mill Manager and Responsible Official at the time these applications were submitted, and it happens that Mr. Wahoske is now the Mill Manager and Primary Responsible Official going forward. Mr. Wahoske or one of his duly designated alternatives will sign all Title V submittals in the future, but we do not think it is necessary under the rules or otherwise to re-submit previously-submitted permit applications, or any other previously-submitted Title V documents, just because the Mill's Responsible Official has changed. The Company's certification of the previously-submitted application is still "good" even though the Mill Manager/Responsible Official has changed. We question whether such a change in Responsible Officials is a valid or legitimate basis to hold up permit processing via an RAI.

The requested forms are included in Attachment H.

35. The Department did not receive the results of the SO_2 air dispersion modeling mentioned on page 4-2 of the RB's and LK's application. This modeling should include not only mill-wide SO_2 emissions due to the mill operating at the projected highest short-term limits, but all applicable nearby sources, and should include predicted impacts in both the PSD Class I and Class II areas. This modeling is required by Rule 62-212.300(1), F.A.C.

A report answering this question is included in Attachment I. Note that the modeled emissions for RB SO2 included a 24-hour average of 100 ppm and a 3-hour average of 150 ppm. Also included on page 3 of the report are the results of the modeling of Recovery Boiler start-up emissions when No. 6 Fuel Oil is used as the start-up fuel. **The modeling shows that the Florida AAQS's for SO2 are being met during Recovery Boiler start-ups.**

Appropriate data files have been sent electronically to Mr. Cleve Holladay at DEP.

36. In Section 2.6.4 on page C-7 of the RB's and LK's application, the maximum receptor distance for the significant impact analyses is given as 4 km. Please provide the justification for this distance.

As stated at the top of page C-7, receptors used in the significant impact analysis extended out 4 km from the Mill. It is also stated on this page that predicted concentrations exceeding the significant impact level (SIL) for PM_{10} and NO_2 were all located within 2 km of the modeling origin. It is further stated on page C-8 that the significant impact distances for PM_{10} and NO_2 were 1.0 km and 0.8 km, respectively. Therefore, the maximum receptor distance of 4 km was more than adequate to capture the points of maximum impact due to the project.

37. If the responses to any of the Department's comments above change the pollutant emission rates or stack configurations, these changes should be evaluated by the appropriate air dispersion modeling and the results provided to the Department.

This was done to the extent necessary to respond to the Department's questions. See response to question 35.

38. Please provide a facility plot plan in AUTOCAD format, which shows the location of all stacks, buildings, fence lines and roads. This plot plan should have a scale and be in UTM coordinates.

The appropriate data files are being submitted electronically to the Department by Golder Associates. A hard copy of the facility plot plan showing the requested information and UTM coordinates is in Attachment J.

39. If any response to the above issues affect the application submittal, please correct and/or change the application to reflect the additional analyses and submit.

As needed, application updates and information are included in the attachments as indicated throughout this response report.

If you have any questions regarding this matter, please contact Myra Carpenter at 386-329-0918.

Sincerely,

Keith Wahoske

Keith W. Wahoske, Vice-President
Palatka Operations

cc: David Buff, P.E., Golder
T. Champion, T. Wyles, S. Matchett, Myra J. Carpenter, GP
Mr. Christopher Kirts, P.E. - FLDEP

LIST OF ATTACHMENTS

ATTACHMENT A (Q-5)
D. Buff letter to R. Felton-Smith – dated 6/30/04

ATTACHMENT B (Q-12)
No. 4 CB – Emissions data summary for NOx and SO2

ATTACHMENT C (Q-13)
Updated Process Flow Diagram – No. 4 CB – (GP-EU1-I1)

ATTACHMENT D (Q-13/26)
Updated No. 5 PB ESP data table (GP-EU1-I3)

ATTACHMENT E (Q-14)
Updated No. 4 CB ESP data table (GP-EU1-I3)

ATTACHMENT F (Q-29)
Summary of Proposed Selection of BACT for Lime Kiln

ATTACHMENT G (Q-33)
Revised Facility Plot Plan showing the No. 5 PB.

ATTACHMENT H (Q-34) -cb
Updated Application signature forms

ATTACHMENT I (Q-35)
Recovery Boiler SO2 Modeling Report

ATTACHMENT J (Q-36)
Facility Plot Plan – Showing boundaries and UTM
AutoCAD format sent electronically

ATTACHMENT K (Q-2)
Table 3-1 (11/14/01); GP-EU1-G8 a & b (10/29/03)

ATTACHMENT L (Q-9)
Updated Tables 2-1, 2-3, and 3-3 – No. 4 CB PSD

ATTACHMENT A (Q-5)

D. Buff letter to R. Felton-Smith – dated 6/30/04

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

received 7/06/04

Golder Associates

June 30, 2004

0337567

Ms. Rita Felton-Smith
Florida Department of Environmental Protection
7825 Baymeadows Way, Suite B200
Jacksonville, FL 32256-7590

**RE: MACT APPLICATION FOR BROWN STOCK WASHER AND OXYGEN DELIGNIFICATION SYSTEM
GEORGIA PACIFIC CORPORATION, PALATKA, FLORIDA
DEP FILE NO. 1070005-024-AC
RESPONSE TO SUPPLEMENTAL INFORMATION REQUEST**

Dear Ms. Felton-Smith:

At Georgia-Pacific's (GP's) request, I am providing the supplemental information requested in your recent email.

Attached find an updated page 2-2 from the original air construction permit application. This corrected page now includes all the major equipment items GP is planning on installing.

Calculations documenting that the HVLC/LVHC NCG gases will be subject to a minimum of 1,200 deg. F for at least 0.5 seconds is provided below for both the No. 4 Combination Boiler and the No. 5 Power Boiler.

No. 4 Combination Boiler :

Furnace volume = 12,000 ft^3

Furnace temperature (based on Babcock and Wilcox design) = 2,200°F

Gas flow rate at stack (avg. from last two stack tests) = 107,100 dscfm @ 16% H_2O

Flow rate through furnace = 107,100 dscfm x (2,660°R ÷ 528°R) ÷ (1 – 0.16) = 642,260 acfm

Residence time of gases in furnace = 12,000 ft^3 ÷ 642,260 acfm x 60 sec/min = 1.1 sec

As shown, the calculated residence time of the gases in the furnace is greater than 0.5 second.

No. 5 Power Boiler :

Furnace volume = 9,600 ft^3

Furnace temperature (based on Babcock and Wilcox design) = 2,300°F

Gas flow rate at stack (avg. from last two stack tests) = 142,600 dscfm @ 11% H_2O

Flow rate through furnace = 142,600 dscfm x (2,760°R ÷ 528°R) ÷ (1 – 0.11) = 837,530 acfm

Residence time of gases in furnace = 9,600 ft^3 ÷ 837,530 acfm x 60 sec/min = 0.7 sec

Please feel free to contact me if you have any questions concerning this information. Attached is the professional engineer certification page to accompany this submittal.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

cc: M. Carpenter, GP
E. Jamro, GP
S. Matchett, GP

Y:\Projects\2003\0337567 Georgia Pacific\4\4.1\061604\L063004-567.doc

Brown Stock Washing System:

- Foam Tanks and Vacuum Tanks
- Best Management Practices (BMP) Tank
- Brown Stock Washers and Vacuum Pumps
- BSW Filtrate Tanks
- Knotters, Screens, and Knotters & Screens Feed Tanks
- Drainers
- Refiner Feed Tank
- Grit Washer
- Weak Black Liquor Tanks
- HVLC System Condensate Standpipe
- High Density Pulp Storage (existing)
- Reject Handling System

Oxygen Delignification System

- Reactor Blow Tank and Blow Tube Vent Condenser
- Reactor Vessels (1st and 2nd stages) (relocated/refurbished)
- Pump Standpipes
- White Liquor Oxidation System
- Washer Filtrate Tanks
- Oxygen Delignification Washer
- Chemical Mixers, MC pumps

Bleach Plant

- Pre-wash System (existing)

Black Liquor Filter

- Pressure Filter (existing, to be relocated)

A flow diagram of the existing BSW system at Palatka is presented in Figure 2-1. The future system flow diagram is shown in Figure 2-2. A plot plan of the proposed systems is presented in Attachment GP-FI-C2 of the application form.

2.2 BROWN STOCK WASHING SYSTEMS

The brown stock washing configuration will be based on the processing of various pulp grades. The three pulp grades manufactured at the Palatka Mill include RP, soft pine (SP), and hardwood (Hwd). RP is high Kappa softwood pulp, used for manufacture of natural Kraft paper. SP is low Kappa softwood pulp used for the manufacture of bleached pulp grades. Hwd is pulp also used for the manufacture of bleached pulp grades.

Pulp from the blow tanks will be sent through pressure knotters and/or pressure screens. These are enclosed devices which will be vented to the HVLC system. The pulp will then be sent through the

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff**
   Registration Number: **19011**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **6241 NW 23rd Street, Suite 500**
   City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3. Professional Engineer Telephone Numbers...
   Telephone: (352) 336 - 5600 ext. Fax: (352) 336 - 6603
4. Professional Engineer Email Address: dbuff@golder.com
5. Professional Engineer Statement:

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

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

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

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

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

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

David A. Buff — 6/30/04

Signature — Date

(seal)

* Attach any exception to certification statement.

** Board of Professional Engineers Certificate of Authorization #00001670

ATTACHMENT B (Q-12)

No. 4 CB – Emissions data summary for NOx and SO2

#4 Combination Boiler - SO2 and NOx Testing

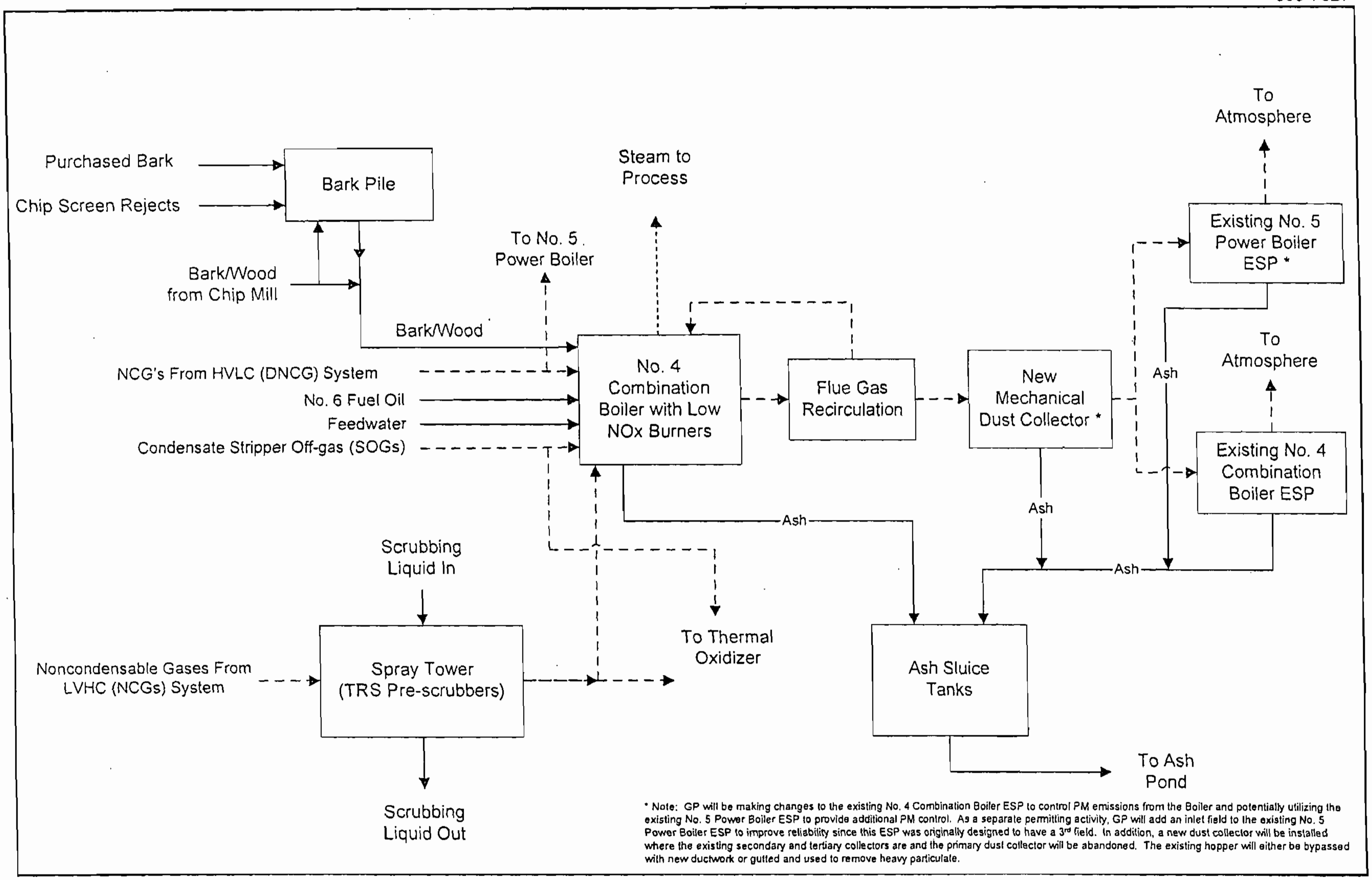
October 25 to 27, 2005

	BARK TPH	OIL KPPH	DATE	START TIME	END TIME	average NOx ppm	NOx lbs/hr	NOx lbs/mmbtu calc.'d Test cond.	NOx lbs/mmbtu From EPA-emmis-factors	average SO2 ppm	SO2 Stack lbs
TEST 1	39.6	0.795	25-Oct-05	22:20	23:00	141.1	93.5	0.24	0.27	39.5	24
TEST 2	35.9	5.61	26-Oct-05	15:47	16:27	144.1	95.5	0.21	0.26	299.7	184
TEST 3	28	8.44	27-Oct-05	2:15	3:15	156.1	103.5	0.24	0.29	335.7	309
TEST 4	16.9	7.42	26-Oct-05	18:15	19:15	122.6	81.3	0.27	0.3	277.7	255
TEST 5	40.1	3.18	26-Oct-05	16:25	17:20	138.8	92.0	0.21	0.23	236.5	199
TEST 6	40.1	0.797	25-Oct-05	16:00	17:00	155.6	103.2	0.26	0.28	314.5	289
TEST 7	0	19.33	26-Oct-05	6:00	7:00	157.5	104.4	0.28	0.35	649.1	597
TEST 8	0	15.88	25-Oct-05	11:53	12:24	152.4	101.0	0.34	0.39	808.5	384
TEST 9	0	18.69	25-Oct-05	13:00	14:00	172.9	114.6	0.32	0.38	861.8	793

Notes
1. Sulfur dioxide emissions from Bark estimated at 0.025 lbs SO2 / mmbtu from bark; for GP Palatka bark = 4750 btu/lb
2. Sulfur in oil approximately 1.8% based on Sept.-05 tests.

ATTACHMENT C (Q-13)

Updated Process Flow Diagram – No. 4 CB – (GP-EU1-I1)



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

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

Process Flow Legend

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

Filename: 4.4 No. 4 CB/GP-EU1-I1_061306.VSD
Date: 09/18/06

Golder Associates

ATTACHMENT D (Q-13/26)

Updated No. 5 PB ESP data table (GP-EU1-I3)

ATTACHMENT D

CONTROL EQUIPMENT
NO. 5 POWER BOILER

The No. 5 Power Boiler is equipped with an electrostatic precipitator (ESP) for particulate control. Design information for the ESP is presented below.

Parameter	Electrostatic Precipitator
Manufacturer	Research Cottrell
No. of Fields	2
Gas Flowrate (acfm)	230,000
Primary Voltage (V)	0-600
Secondary Voltage (kVdc)	0-90
Primary Current (A)	0-150
Secondary Current (A)	0-1.0
Control Efficiency (%)	40% to 65%

Note: A third field will be installed in the existing chamber of the ESP Design data is not yet available for the third field; however, design will be consistent with design of the existing fields.

ATTACHMENT E (Q-14)

Updated No. 4 CB ESP data table (GP-EU1-I3)

ATTACHMENT E

CONTROL EQUIPMENT
NO. 4 COMBINATION BOILER

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

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

Parameter	**No. 4 Combination Boiler - Electrostatic Precipitator**
Manufacturer	Research Cottrell
Inlet Gas Temp (°F)	450
Gas Flow Rate (ACFM)	230,000
Primary Voltage (V)	0-600
Secondary Voltage (kVdc)	0-90
Primary Current (A)	0-150
Secondary Current (A)	0-1.0
Control Efficiency (%)	99.5

The existing No. 5 Power Boiler ESP may also be used for particulate matter control for the No. 4 Combination Boiler exhaust. Design information for the No. 5 Power Boiler ESP is presented below.

Parameter	**No. 5 Power Boiler Electrostatic Precipitator**
Manufacturer	Research Cottrell
Inlet Gas Temp (°F)	450
Gas Flowrate (acfm)	230,000
Primary Voltage (V)	0-600
Secondary Voltage (kVdc)	0-90
Primary Current (A)	0-150
Secondary Current (A)	0-1.0
Control Efficiency (%)	40-65

ATTACHMENT F (Q-29)

Summary of Proposed Selection of BACT for Lime Kiln

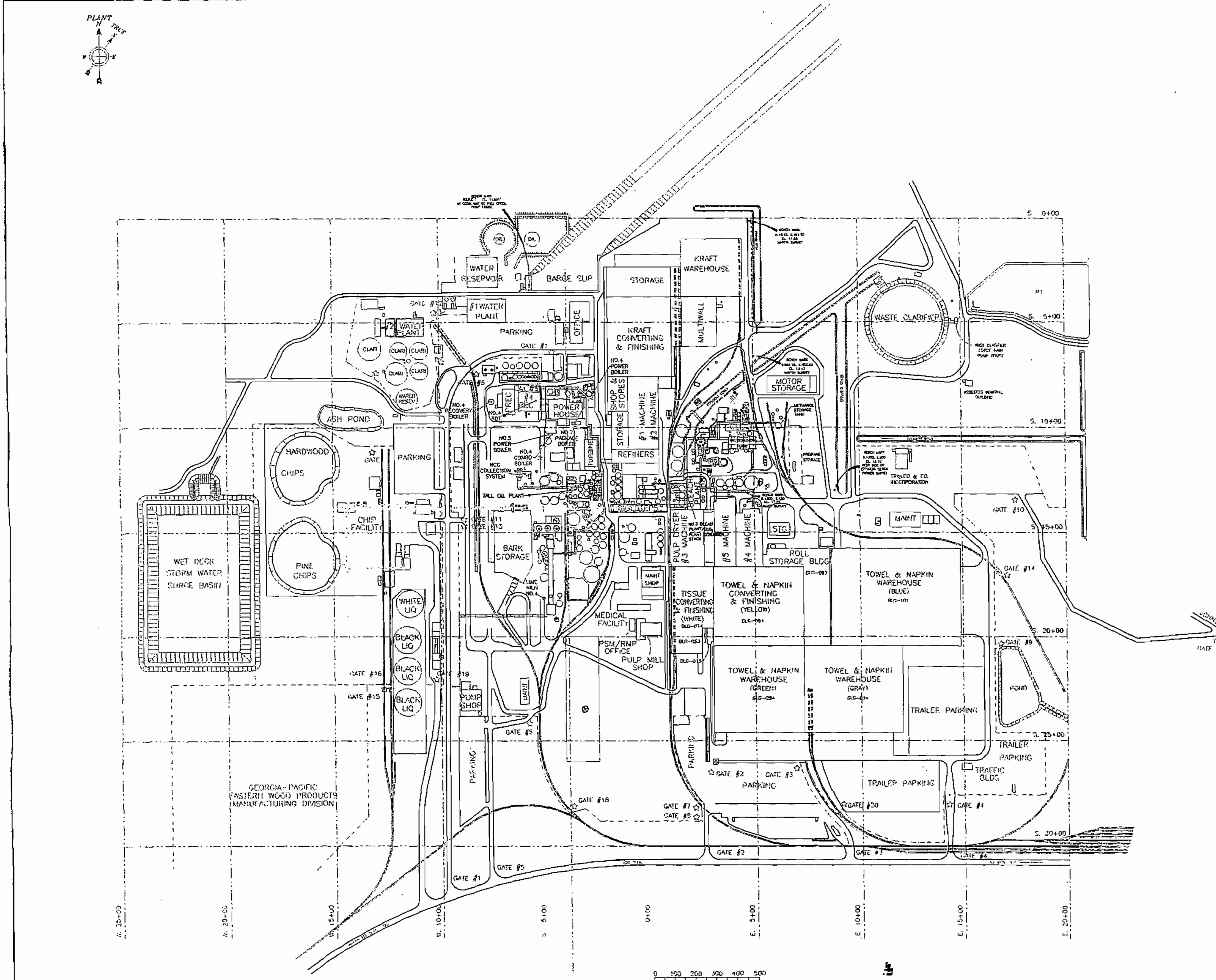
Table E-7. Summary of Proposed Selection of BACT for Lime Kiln

Pollutant	Control Technology	Ranking	Destruction Efficiency or Emission Rate
NO_x	Good Combustion	1	175 ppmvd at 10% O_2
PM/PM_{10}	Venturi Scrubber	3	0.064 gr/dscf at 10% O_2
VOC	Good Combustion/Proper Design and Operation	1	70 ppmvd at 10% O_2
CO	Good Combustion Practices	1	69 ppmvd at 10% O_2
SAM	No Controls	1	0.4 lbs/hr (1.8 tons/yr)

ATTACHMENT G (Q-33)

Revised Facility Plot Plan showing the No. 5 PB.

BEST AVAILABLE COPY



NOTE: NO. 6 PACKAGE BOILER IS UNDERGOING REPAIRS AND HAS NOT BEEN LOCATED YET

NOTES

LEGEND & INFORMATION

☆	GATE
—+—+—	RAILROAD TRACK
— —	FENCE

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

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

Georgia-Pacific

THE GROWTH COMPANY

PALATKA OPERATIONS

ATTACHMENT C
FACILITY PLOT PLAN, PALATKA MILL
0537627\0100\-1.1\Plot Plan .dwg

G-P DRAWING NO.
290-8464MI -000-0009-006

CONSULTANT NO.

ATTACHMENT H (Q-34)

Updated Application signature forms

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name: **Mr. Keith W. Wahoske, Vice-President**
2.	Owner/Authorized Representative Mailing Address: Organization/Firm: **Georgia-Pacific Corporation** Street Address: **P.O. Box 919** City: **Palatka** State: **FL** Zip Code: **32178**
3.	Owner/Authorized Representative Telephone Numbers: Telephone: **(386) 325-2001** ext. Fax: **(386) 328-0014**
4.	Owner/Authorized Representative Email Address: **keith.wahoske@GAPAC.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* Keith Wahoske 9/22/2006 Signature Date

Professional Engineer Certification

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

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

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

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

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

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

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

David A. Buff
Signature

9/19/06
Date

(seal)

* Attach any exception to certification statement.
** **Board of Professional Engineers Certificate of Authorization #00001670**

ATTACHMENT I (Q-35)

Recovery Boiler SO2 Modeling Report

ATTACHMENT I

As described in the prevention of significant deterioration (PSD) application, page 4-2, Georgia-Pacific Corporation (GP) has performed atmospheric dispersion modeling of higher short-term sulfur dioxide (SO_2) emissions from the No. 4 Recovery Boiler. For the 3-hour averaging time, SO_2 emissions from the No. 4 Recovery Boiler are based upon 150 parts per million by volume dry (ppmvd) at 8 percent oxygen (O_2). For the 24-hour averaging time, they are based upon 100 ppmvd at 8 percent O_2, and for the annual averaging time, they are based upon 12 ppmvd at 8 percent. The Palatka Mill SO_2 emission inventory used in the modeling analysis is presented in Tables I-1 and I-2. The emissions are consistent with recent permit applications submitted by GP, including the No. 4 Combination Boiler application and the Title V revision application for the Brown Stock Washing System. The Palatka Mill stack parameters are shown in Table I-3, and are the same as presented in the July 2006 permit application (Attachment C - Air Quality Analyses).

As shown in the tables, there are four emission scenarios. For each averaging time, Scenarios 2 and 4 have higher and equal total SO_2 emissions. However, Scenario 4 results in higher SO_2 emissions from the No. 5 Power Boiler as compared to the No. 4 Combination Boiler. Since both sources have the same stack height, but the No. 5 Power Boiler has a lower flue gas flow rate, the No. 5 Power Boiler will have a lower plume rise than the No. 4 Combination Boiler. Therefore, Scenario 4 was modeled as the worst-case condition.

SO_2 PSD Class II and AAQS Analyses

In May 2006, the Florida Department of Environmental Protection (FDEP) developed meteorological data from the Jacksonville International Airport for the years 2001 to 2005, and requested that applications use the data for future American Meteorological Society (AMS)/U.S. Environmental Protection Agency (EPA) Regulatory Model (AERMOD) modeling applications. The meteorological data were revised by FDEP to fill in missing upper air soundings in the original data set and provided to Golder Associates Inc. (Golder) in June 2006. The current air modeling analyses uses the revised meteorological data set to address compliance with the SO_2 Ambient Air Quality Standard (AAQS) and allowable PSD Class II increments in the vicinity of the Palatka Mill.

The modeling analysis was performed for the 3-hour, 24-hour, and annual averaging times, using GP's future maximum SO_2 emission rates. PSD baseline emissions were consistent with previous SO_2 modeling analysis (for example, the 2001-2002 modeling performed for the MACT I Compliance Pollution Control). All non-GP sources were modeled consistent with recent modeling analysis performed for Seminole Electric Cooperative, Inc. (SECI). The modeled configuration for SECI is consistent with the preliminary determination issued by FDEP, based on proposed improvements to be performed.

Summaries of the SO_2 AAQS and PSD Class II increment modeling analyses are presented in Tables I-4 and I-5. As shown in these tables, the maximum SO_2 concentrations predicted for the future Palatka Mill, together with background sources, complies with the SO_2 federal and Florida AAQS and with allowable PSD Class II increments.

SO_2 PSD Class I Increment Analysis

In order to provide a complete assessment of SO_2 PSD Class I increment consumption using the 2001-2003 California Puff (CALPUFF) meteorological data at the PSD Class I areas within 200 kilometers (km) of the Palatka Mill, air modeling analyses were performed for both the Okefenokee and Chassahowitzka National Wilderness Areas (NWAs). These meteorological data were made available and obtained from the FDEP in mid-April 2006. Previous modeling analyses were performed using the meteorological data for 1990, 1992, and 1996 as recommended by FDEP, EPA, and Federal Land Managers.

The modeling analysis was performed for the 3-hour, 24-hour, and annual averaging times, using GP's future maximum SO_2 emission rates. PSD baseline emissions were consistent with previous SO_2 modeling analysis (for example, the 2001-2002 modeling performed for the MACT I Compliance Pollution Control). All non-GP sources were modeled consistent with recent modeling analysis performed for SECI. The modeled configuration for SECI is consistent with the preliminary determination issued by FDEP, based on proposed improvements to be performed.

Summaries of the SO_2 PSD Class I increment modeling for the Chassahowitzka and Okefenokee NWAs using the CALPUFF meteorological data for 2001 to 2003 are presented in Tables I-6 and I-7, respectively. As shown in Table I-6, the maximum SO_2 concentrations predicted for the Palatka Mill, together with background sources, comply with the PSD Class I increments at the Okefenokee NWA.

As shown in Table I-7, the maximum SO_2 concentrations are predicted to exceed the allowable 24-hour increment at the Chassahowitzka NWA in 2002 and 2003 and also exceed the 3-hour PSD Class I increment in 2001, 2002, and 2003. The maximum predicted impact for each time period is presented in Table I-8, along with the contribution from the Palatka Mill's PSD increment consuming emissions. The Palatka Mill's contribution is predicted to be less than the PSD Class I significant impact levels for each 3-hour and 24-hour time period in which the allowable PSD Class I increments are exceeded. Therefore, the future Palatka Mill SO_2 emissions are not predicted to significantly impact any predicted exceedances at the Chassahowitzka NWA.

Recovery Boiler Startup Emissions

GP also investigated potential SO_2 impacts during a No. 4 Recovery Boiler startup event. During these events, No. 6 fuel oil is burned without any black liquor firing in the boiler. Under these conditions, the SO_2 emissions generated due to the fuel oil firing, are not absorbed into the furnace bed since the bed has not yet been established by burning black liquor. It is presumed under these conditions that all sulfur in the fuel oil exhausts out of the stack as SO_2.

GP reviewed past records of fuel oil firing during startup conditions, and found that the maximum No. 6 fuel oil burning rate would be 80 gallons per minute (gal/min) [4,800 gallons per hour (gal/hr)] for a 3-hour period, and 45 gal/min (2,700 gal/hr) for a 24-hour period. The potential SO_2 emissions are calculated as follows:

3-hr: 4,800 gal/hr x 8.2 pounds per gallon (lb/gal) x (0.0235 lb Sulfur (S)/lb oil)

x (mole SO_2/mole S) x (64 lb SO_2/mole SO_2)

x (mole S/32 lb S) = 1,849.9 lb/hr SO_2

24-hr: 2,700 gal/hr x 8.2 lb/gal x (0.0235 lb S/lb oil) x (mole SO_2/mole S)

x (64 lb SO_2/mole SO_2) x (mole S/32 lb S) = 1,040.6 lb/hr SO_2

Stack exhaust flow rate measurements were also obtained during a typical startup, and the testing indicated an average gas flow rate of 294,000 actual cubic feet per minute (acfm) and a stack temperature of 300 degrees Fahrenheit (°F).

The AAQS impacts were then re-evaluated with these stack parameters and emissions (PSD Class II and Class I increments were not evaluated since these are startup conditions). The results of the AAQS modeling are shown in Table I-9. As shown, all maximum impacts are below the AAQS.

TABLE I-1
MAXIMUM SHORT-TERM SO_2 EMISSIONS FOR GEORGIA-PACIFIC, PALATKA
2.35 PERCENT SULFUR CONTENT FUEL OIL AND MAXIMUM PULP PRODUCTION RATES
(REVISED JUNE 19, 2006)

Emission Unit	Unit ID	3-Hr Emissions (lb/hr)	3-Hr Emissions (g/s)	24-Hr Emissions (lb/hr)	24-Hr Emissions (g/s)
SCENARIO 1: LVHC NCGs/SOGs to THERMAL OXIDIZER HVLC DNCGs to NO. 4 COMBINATION BOILER					
Thermal Oxidizer w/LVHC	TO	31.3	3.95	31.3	3.95
No. 4 Recovery Boiler (150 ppm/100 ppm)	RB4	439.6	55.39	292.8	36.89
No. 4 Smelt Dissolving Tank	SDT4	7.7	0.97	7.7	0.97
No. 4 Lime Kiln	LK4	9.1	1.15	9.1	1.15
No. 5 Power Boiler	PB5	1,461.7	184.17	1,461.7	184.17
No. 7 Power Boiler	PB7	0.0	0.00	0.00	0.00
No. 4 Combination Boiler w/HVLC	CB4	1,158.1	145.92	1,142.6	143.97
TOTALS		3,107.5	391.5	2,945.2	371.1
SCENARIO 2: LVHC NCGs/SOGs to NO. 4 COMBINATION BOILER HVLC DNCGs to NO. 4 COMBINATION BOILER					
Thermal Oxidizer	TO	0.0	0.00	0.0	0.00
No. 4 Recovery Boiler (150 ppm/100 ppm)	RB4	439.6	55.39	292.8	36.89
No. 4 Smelt Dissolving Tank	SDT4	7.7	0.97	7.7	0.97
No. 4 Lime Kiln	LK4	9.1	1.15	9.1	1.15
No. 5 Power Boiler	PB5	1,461.7	184.17	1,461.7	184.17
No. 7 Power Boiler	PB7	0.0	0.00	0.00	0.00
No. 4 Combination Boiler w/ LVHC & HVLC	CB4	2,117.0	266.74	1,921.0	242.05
TOTALS		4,035.1	508.4	3,692.3	465.2
SCENARIO 3: LVHC NCGs/SOGs to THERMAL OXIDIZER HVLC DNCGs to NO. 5 POWER BOILER					
Thermal Oxidizer w/LVHC	TO	31.3	3.95	31.3	3.95
No. 4 Recovery Boiler (150 ppm/100 ppm)	RB4	439.6	55.39	292.8	36.89
No. 4 Smelt Dissolving Tank	SDT4	7.7	0.97	7.7	0.97
No. 4 Lime Kiln	LK4	9.1	1.15	9.1	1.15
No. 5 Power Boiler w/HVLC	PB5	1,544.3	194.58	1,528.8	192.63
No. 7 Power Boiler	PB7	0.0	0.00	0.00	0.00
No. 4 Combination Boiler	CB4	1,075.5	135.51	1,075.5	135.51
TOTALS		3,107.5	391.5	2,945.2	371.1
SCENARIO 4: LVHC NCGs/SOGs to NO. 4 COMBINATION BOILER HVLC DNCGs to NO. 5 POWER BOILER					
Thermal Oxidizer	TO	0.0	0.00	0.0	0.00
No. 4 Recovery Boiler (150 ppm/100 ppm)	RB4	439.6	55.39	292.8	36.89
No. 4 Smelt Dissolving Tank	SDT4	7.7	0.97	7.7	0.97
No. 4 Lime Kiln	LK4	9.1	1.15	9.1	1.15
No. 5 Power Boiler w/HVLC	PB5	1,544.3	194.58	1,528.8	192.63
No. 7 Power Boiler	PB7	0.0	0.00	0.0	0.00
No. 4 Combination Boiler w/ LVHC	CB4	2,034.4	256.33	1,854.3	233.64
TOTALS		4,035.1	508.4	3,692.7	465.3

Note: Emissions due to LVHC and HVLC NCGs based on pulp production rates of 118 TPH and 2,300 TPD ADUP.

TABLE I-2
MAXIMUM LONG-TERM SO_2 EMISSIONS FOR GEORGIA-PACIFIC, PALATKA
2.35 PERCENT SULFUR CONTENT FUEL OIL
(REVISED JUNE 19, 2006)

Emission Unit	Unit ID	Annual Emissions (TPY)	Annual Emissions (g/s)
SCENARIO 1: LVHC NCGs/SOGs to THERMAL OXIDIZER 100%			
HVLC DNCGs to NO. 4 COMBINATION BOILER 100%			
Thermal Oxidizer w/LVHC	TO	137.2	3.95
No. 4 Recovery Boiler	RB4	153.9	4.43
No. 4 Smelt Dissolving Tank	SDT4	33.7	0.97
No. 4 Lime Kiln	LK4	40.0	1.15
No. 5 Power Boiler	PB5	6,402.3	184.18
No. 7 Power Boiler	PB7	0.0	0.00
No. 4 Combination Boiler w/HVLC	CB4	1,260.1	36.25
TOTALS		8,027.2	230.9
SCENARIO 2: LVHC NCGs/SOGs to THERMAL OXIDIZER 80%			
LVHC NCGs/SOGs to NO. 4 COMBINATION BOILER 20%			
HVLC DNCGs to NO. 4 COMBINATION BOILER 100%			
Thermal Oxidizer w/LVHC	TO	109.8	3.16
No. 4 Recovery Boiler	RB4	153.9	4.43
No. 4 Smelt Dissolving Tank	SDT4	33.7	0.97
No. 4 Lime Kiln	LK4	40.0	1.15
No. 5 Power Boiler	PB5	6,402.3	184.18
No. 7 Power Boiler	PB7	0.0	0.00
No. 4 Combination Boiler w/ LVHC & HVLC	CB4	1,808.8	52.03
TOTALS		8,548.5	245.9
SCENARIO 3: LVHC NCGs/SOGs to THERMAL OXIDIZER 100%			
HVLC DNCGs to NO. 5 POWER BOILER 100%			
Thermal Oxidizer	TO	137.2	3.95
No. 4 Recovery Boiler	RB4	153.9	4.43
No. 4 Smelt Dissolving Tank	SDT4	33.7	0.97
No. 4 Lime Kiln	LK4	40.0	1.15
No. 5 Power Boiler w/HVLC	PB5	6,638.6	190.97
No. 7 Power Boiler	PB7	0.0	0.00
No. 4 Combination Boiler	CB4	982.8	28.27
TOTALS		7,986.2	229.7
SCENARIO 4: LVHC NCGs/SOGs to THERMAL OXIDIZER 80%			
LVHC NCGs/SOGs to NO. 4 COMBINATION BOILER 20%			
HVLC DNCGs to NO. 5 POWER BOILER 100%			
Thermal Oxidizer	TO	109.8	3.16
No. 4 Recovery Boiler	RB4	153.9	4.43
No. 4 Smelt Dissolving Tank	SDT4	33.7	0.97
No. 4 Lime Kiln	LK4	40.0	1.15
No. 5 Power Boiler w/HVLC	PB5	6,638.6	190.97
No. 7 Power Boiler	PB7	0.0	0.00
No. 4 Combination Boiler w/ LVHC	CB4	1,572.5	45.24
TOTALS		8,548.5	245.9

TABLE I-3
LOCATIONS AND STACK PARAMETERS FOR POINT SOURCES FOR NAAQS IMPACT ANALYSIS - GP PALATKA MILL

Model ID	Description	Stack Parameters									
		Source Location UTM		Stack Height		Stack Exit Temp		Stack Velocity		Stack Diameter	
		East (m)	North (m)	(ft)	(m)	F	K	(fps)	(m/s)	(ft)	(m)
TOX	Thermal Oxidizer	433996.65	3283401.08	250	76.2	160	344	18.0	5.49	3.6	1.10
RB4	# 4 Recovery Boiler	433897.37	3283458.89	230	70.1	425	491	65.9	20.08	12.0	3.66
SDT4	# 4 Smelt Dissolving Tanks	433949.76	3283498.51	206	62.8	180	355	34.0	10.35	5.0	1.52
LK4	# 4 Lime Kiln	434121.82	3283267.89	131	39.9	164	346.5	70.6	21.51	4.42	1.35
PB5	# 5 Power Boiler	433992.35	3283468.15	237	72.2	413	485	85.9	26.19	8.0	2.44
PB7	# 7 Package Boiler	434001.27	3283486.88	60	18.3	750	672	43.5	13.25	7.0	2.13
CB4	# 4 Combination Boiler	433997.52	3283471.42	237	72.2	466	514	92.3	28.14	8.0	2.44

TABLE I-4
MAXIMUM PREDICTED SO_2 IMPACTS FOR COMPARISON TO THE FLORIDA AAQS

Averaging Time and Rank	Concentrations (μg/m³)[a] Total (c=a+b)	Modeled Source (a)	Background[a] (b)	Receptor Location UTM Coordinates (m) East	North	Time Period (YYMMDDHH)	Florida Ambient Air Quality Standards (μg/m³)
Highest Annual							
	27.1	21.1	6	434741	3283275	01123124	60
	25.4	19.4	6	434741	3283275	02123124	
	27.5	21.5	6	434629	3283191	03123124	
	26.0	20.0	6	434741	3283275	04123124	
	27.2	21.2	6	434704	3283247	05123124	
HSH 24-Hour							
	179	145	34	434704	3283247	01012024	260
	194	160	34	434554	3283135	02010724	
	190	156	34	434666	3283219	03121724	
	165	131	34	434704	3283247	04040224	
	181	147	34	434704	3283247	05122624	
HSH 3-Hour							
	637	509	128	434666	3283219	01011215	1,300
	642	514	128	434592	3283163	02022712	
	575	447	128	434666	3283219	03042618	
	640	512	128	434629	3283191	04041415	
	642	514	128	434629	3283191	05042718	

Note: YYMMDDHH = Year, Month, Day, Hour Ending.
HSH = Highest, second-highest
AAQS = Ambient Air Quality Standards

[a] Concentrations are based on highest concentrations predicted using AERMOD with five years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service station at Jacksonville International Airport as received from the FDEP.

[b] Background concentrations are highest mean and HSH 24-and 3-hour concentrations, measured during 2004 and 2005 from Palatka monitoring station 12-107-1008.

TABLE I-5
MAXIMUM PREDICTED SO_2 IMPACTS FOR COMPARISON TO
ALLOWABLE PSD CLASS II INCREMENTS

Averaging Time and Rank	Concentration (μg/m³)	Receptor Location UTM Coordinates (m) East	North	Time Period (YYMMDDHH)	Allowable PSD Class II Increment (μg/m³)
Highest Annual					
	7.60	437,200	3,289,200	01123124	20
	7.30	437,100	3,289,100	02123124	
	6.70	440,500	3,289,700	03123124	
	5.40	440,600	3,289,400	04123124	
	6.40	437,300	3,289,600	05123124	
HSH 24-Hour					
	55.0	437,300	3,288,900	01072224	91
	58.8	437,200	3,289,200	02090624	
	59.5	437,300	3,289,700	03090124	
	51.7	437,100	3,290,000	04061324	
	59.7	437,400	3,289,700	05092524	
HSH 3-Hour					
	152.0	438,100	3,290,300	01072615	512
	147.9	437,838	3,290,126	02082915	
	144.5	437,600	3,289,900	03082215	
	149.5	440,338	3,289,319	04053012	
	149.5	437,557	3,289,548	05062215	

Note: YYMMDDHH = Year, Month, Day, Hour Ending.
HSH = Highest, second-highest
PSD = Prevention of Significant Deterioration

[a] Concentrations are based on highest concentrations predicted using AERMOD with 5 years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service station at Jacksonville International Airport as received from the FDEP.

TABLE I-6
MAXIMUM SO_2 IMPACTS PREDICTED FOR COMPARISON TO THE
SO_2 PSD CLASS I INCREMENTS AT THE OKEFENOKEE NWA

Averaging Time/Rank	Maximum Concentration [a] (μg/m³)	Receptor Location LCC Coordinates (km) X	Y	Time Period (YYMMDDHH)	PSD Class I Increment (μg/m³)
Annual					
Highest	0.00[b]	NA	NA	NA	2
	0.00	NA	NA	NA	
	0.00	NA	NA	NA	
24-Hour					
Second-highest	3.99	1,421.564	-921.107	01112924	5
	2.44	1,397.157	-930.757	02010924	
	2.16	1,397.157	-930.757	03111824	
3-Hour					
Second-highest	19.1	1,422.472	-926.620	01121221	25
	16.8	1,416.891	-912.442	02021006	
	24.4	1,419.983	-921.368	03112312	

Note: YYMMDDHH = Year, Month, Day, Hour Ending
LCC = Lambert Conic Conformal
NA = Not Applicable

[a] Based on the CALPUFF model using 3 years of CALMET meteorological data for 2001, 2002, and 2003, 4-km Florida domain.

[b] A "0.00" impact means that the predicted concentration was zero or less. The CALPUFF model does not print a negative concentration.

TABLE 1-7
MAXIMUM SO_2 IMPACTS PREDICTED FOR COMPARISON TO THE
SO_2 PSD CLASS I INCREMENTS AT THE CHASSAHOWITZKA NWA

Averaging Time/Rank	Maximum Concentration [a] ($\mu g/m^3$)	Receptor Location LCC Coordinates (km) X	Y	Time Period (YYMMDDHH)	PSD Class I Increment ($\mu g/m^3$)
Annual					
Highest	0.05	1,411.565	-1,143.104	01123124	2
	0.00 [b]	NA	NA	NA	
	0.00	NA	NA	NA	
24-Hour					
Second-highest	4.91	1,411.565	-1,143.104	01112724	5
	5.85	1,402.723	-1,139.772	02122724	
	7.75	1,405.965	-1,139.257	03082724	
3-Hour					
Second-highest	81.7	1,404.713	-1,136.613	01111012	25
	39.9	1,402.283	-1,136.999	02011524	
	68.9	1,404.638	-1,141.364	03120109	

Note: YYMMDDHH = Year, Month, Day, Hour Ending
LCC = Lambert Conic Conformal
NA = Not Applicable

[a] Based on the CALPUFF model using 3 years of CALMET meteorological data for 2001, 2002, and 2003, 4-km Florida domain.
[b] A "0.00" impact means that the predicted concentration was zero or less. The CALPUFF model does not print a negative concentration.

TABLE I-8
GP PALATKA MILL'S CONTRIBUTION TO TIME PERIODS PREDICTED TO EXCEED THE 24- AND 3-HOUR ALLOWABLE SO_2 INCREMENT AT THE CHASSAHOWITZKA NWA PSD CLASS I AREA

Year	Julian Day	Month	Day	Hour Ending for Period	Maximum Concentration (μg/m³)[a] All Modeled Sources	Maximum Concentration (μg/m³)[a] GP Palatka PSD Only[b]	Class I Significant Impact Level (μg/m³)	Affected Chassahowitzka NWA Receptors[c]
3-Hour Exceedances								
2001	314	11	10	12	81.7	<.001	1.0	35-36, 39-113
2001	314	11	10	15	78.9	<.001	1.0	51, 52, 59, 89, 95, 101, 106, 107, 112, 113
2002	15	1	15	24	39.9	<.0001	1.0	45, 60, 62, 69, 71, 90, 96, 102, 108
2002	15	1	15	21	31.2	<.0001	1.0	54, 84
2002	42	2	11	21	30.9	<.0001	1.0	87, 93, 94, 98, 99, 100
2002	44	2	13	9	31.4	<.0001	1.0	60, 61, 69, 70, 76, 77, 83, 96, 102, 108
2002	332	11	28	9	29.2	<.00001	1.0	108
2002	361	12	27	9	30.1	0.52	1.0	60, 90, 109
2002	361	12	27	12	33.7	0.026	1.0	45, 53, 54, 61, 67-70, 77, 83, 90-91, 96,102, 104-105, 109-111
2003	335	12	1	6	62.0	< 0.06	1.0	37, 45-48, 53-56, 90-94, 98, 99
2003	335	12	1	9	68.9	< 0.05	1.0	57, 60-65, 69-74, 77-81, 83-87
24-Hour Exceedances								
2002	30	1	30	24	5.24	< .00001	0.2	15, 19, 20, 21
2002	352	12	18	24	5.39	0.022	0.2	1-18
2002	361	12	27	24	5.85	0.12	0.2	90
2003	238	8	26	24	5.72	< .001	0.2	4, 9, 15, 21, 40-44, 48-52, 57-59, 65
2003	239	8	27	24	7.75	< .0001	0.2	1-37
2003	279	10	6	24	7.08	0.073	0.2	9, 15, 36, 38-47, 50, 53-56, 61-64, 70-71
2003	335	12	1	24	6.54	0.026	0.2	47, 65, 75, 82, 88, 97, 100, 105

[a] Based on the CALPUFF model using 3 years of CALMET meteorological data for 2001, 2002, and 2003, 4-km Florida domain.
[b] Includes only GP Palatka PSD sources.
[c] Based on 113 National Park Service receptors for Chassahowitzka NWA.

TABLE I-9
MAXIMUM PREDICTED SO_2 IMPACTS FOR COMPARISON TO THE FLORIDA AAQS
INCLUDES START-UP EMISSIONS FOR GP RECOVER BOILER NO 4

Averaging Time and Rank	Concentrations (μg/m³)[a] Total (c=a+b)	Modeled Sources (a)	Background[a] (b)	Receptor Location UTM Coordinates (m) East	North	Time Period (YYMMDDHH)	Florida Ambient Air Quality Standards (μg/m³)
Highest Annual							
	32.0	26.0	6	434741	3283275	01123124	60
	29.7	23.7	6	434704	3283247	02123124	
	32.5	26.5	6	434629	3283191	03123124	
	30.6	24.6	6	434741	3283275	04123124	
	31.9	25.9	6	434704	3283247	05123124	
HSH 24-Hour							
	202	168	34	434704	3283247	01030524	260
	221	187	34	434554	3283135	02010724	
	218	184	34	434666	3283219	03121724	
	192	158	34	434704	3283247	04040224	
	207	173	34	434592	3283163	05040224	
HSH 3-Hour							
	775	647	128	434629	3283191	01122612	1,300
	792	664	128	434554	3283135	02101612	
	707	579	128	434629	3283191	03042618	
	783	655	128	434629	3283191	04041415	
	784	656	128	434629	3283191	05042718	

Note: YYMMDDHH = Year, Month, Day, Hour Ending.
HSH = Highest, second-highest
AAQS = Ambient Air Quality Standards

[a] Concentrations are based on highest concentrations predicted using AERMOD with five years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service station at Jacksonville International Airport as received from the FDEP.

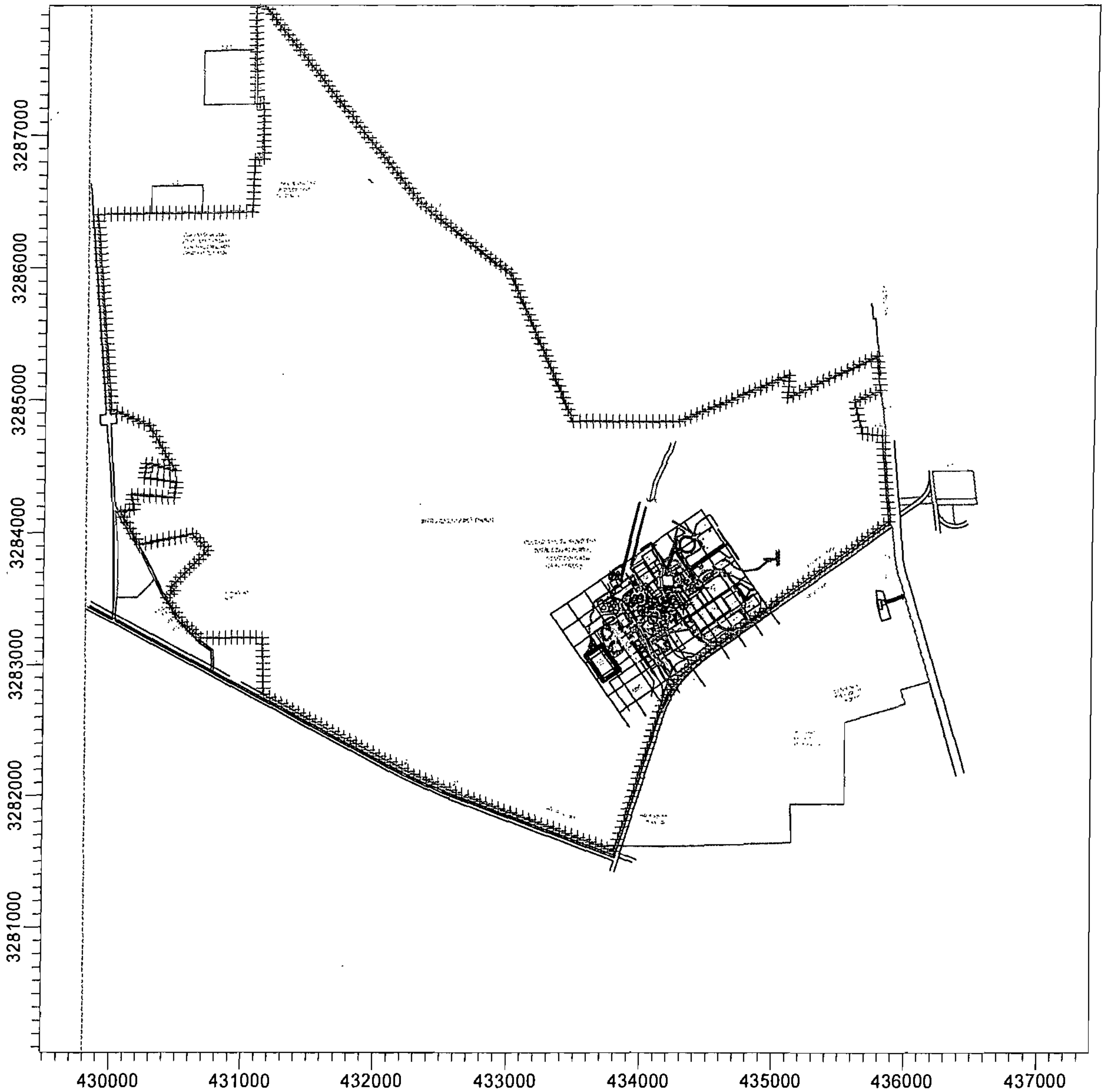
[b] Background concentrations are highest mean and HSH 24-and 3-hour concentrations, measured during 2004 and 2005 from Palatka monitoring station 12-107-1008.

ATTACHMENT J (Q-36)

Facility Plot Plan – Showing boundaries and UTM
AutoCAD format sent electronically

PROJECT TITLE:

GP PALATKA NEW PROPERTY BOUNDARY



COMMENTS:

SOURCES:
34

COMPANY NAME:

RECEPTORS:
2124

MODELER:

SCALE: 1:48,286
0 1 km

DATE:
9/22/2006

PROJECT NO.:

ATTACHMENT K (Q-2)

Table 3-1 (11/14/01); GP-EU1-G8 a & b (10/29/03)

Table 3-1. TRS, SO_2, and SAM Emissions Due to NCG/SOG Destruction:

Final Compliance Scenario: LVHC NCGs and SOGs to New Thermal Oxidizer with No. 4 Combination Boiler Backup

NCG Source	Uncontrolled TRS Emissions (a) (lb/hr)	Potential Uncontrolled SO_2 Emissions (lb/hr)	Sulfur Removal Efficiency (%)	SO_2 Control Efficiency (%)	Maximum SO_2 Emission Rate		Controlled TRS Emission Rate		Maximum SAM Emission Rate	
					lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
OPTION 1: LVHC/SOGs to NEW THERMAL OXIDIZER @ 100%										
LVHC NCGs	**378**	**756**	60 (b)	95 (c)	15.1	66.2				
Condensate Stripper Off-Gas	**162**	**324**	0	95 (c)	16.2	71.0				
TOTALS	**540**				**31.3**	**137.2**	**0.16 (f)**	**0.71**	**2.2 (h)**	**9.6**
OPTION 2: LVHC/SOGs to NEW THERMAL OXIDIZER @ 80%; NO. 4 CB @ 20%										
TO NEW THERMAL OXIDIZER @ 80%:										
LVHC NCGs	**378**	**756**	60 (b)	95 (c)	15.1	53.0				
Condensate Stripper Off-Gas	**162**	**324**	0	95 (c)	16.2	56.8				
Subtotal	**540**				**31.3**	**109.7**	**0.16 (f)**	**0.57**	**2.2 (h)**	**7.7**
TO NO. 4 COMBINATION BOILER @ 20%:										
LVHC NCGs	**378**	**756**	60 (b)	0 (d)	302.4	264.9	0.378 (g)	0.33	12.1 (i)	10.6
Condensate Stripper Off-Gas	**162**	**324**	0	0 (d)	324.0	283.8	0.162 (g)	0.14	13.0 (i)	11.4
Subtotal	**540**				**626.4**	**548.7**	**0.54**	**0.47**	**25.1**	**21.9**
TOTALS						**658.5** (d) 389.2 (e)		**1.04**		**29.7**

Note:

NCG = noncondensable gases; SO_2 = sulfur dioxide; LVHC = low volume, high concentration

TRS = total reduced sulfur; SAM = sulfuric acid mist

(a) As sulfur, for pulp production rate of 1,850 TPD ADUP. Based on engineering estimates and test data, which shows 70%/30% split of S between NCGs/SOGs.

(b) TRS pre-scrubber provides minimum of 60% sulfur removal.

(c) Design efficiency of SO_2 scrubber serving the new Thermal Oxidizer.

(d) No removal of SO_2 in No. 4 Combination Boiler is assumed.

(e) NCASI studies show that there is SO_2 absorption in the boiler from bark burning. Based on this study, the average SO_2 removal when burning carbonaceous fuels is as follows.

Sulfur capture derivation:

avg tons bark =	35 TPH
sulfur input due to TRS burning =	313
tons wood per lb sulfur input = X =	0.1117
% capture = $122.34 * X^{0.5}$ =	40.9 %

Reference: NCASI Tech. Bulletin 640, Sept. 1992.

(f) Based on Florida limit of 5 ppmvd @ 10% O_2 and new Thermal Oxidizer flow rate of 6,160 dscfm @ 10% O_2.

(g) Assumes 99.9% TRS destruction in new Thermal Oxidizer or combination boiler.

(h) Vendor information for emissions after candle mist eliminator.

(i) Assumes SAM emissions are equivalent to 4% of SO_2 emissions, based on AP-42 for combustion sources.

Attachment GP-EU1-G8a. Estimated Maximum Short-Term TRS, SO_2, and SAM Emissions From Power Boilers Due to HVLC DNCG Stream Combustion Only, Georgia-Pacific Palatka

Source	Uncontrolled TRS Emissions [a] (lb S/ton ADUP)	Maximum Pulp Production Rate [b]		Maximum SO_2 Emission Rate [d]		Maximum TRS Emission Rate (lb/hr)	Maximum SAM Emission Rate [g]	
		tons/hr ADUP	tons/day ADUP	lb/hr	lb/day		lb/hr	lb/day
SCENARIO 1: NO. 4 COMBINATION BOILER								
HVLC DNCGs	0.35	118.0	2,300	82.6	1,610	3.6 [e]	3.3	64.4
SCENARIO 2: NO. 5 POWER BOILER								
HVLC DNCGs	0.35	118.0	2,300	82.6	1,610	3.9 [f]	3.3	64.4

Notes:

NCG = noncondensable gases
DNCG= dilute NCG
S= sulfur
SO_2 = sulfur dioxide
HVLC = high volume, low concentration
TRS = total reduced sulfur
ADUP= air-dried unbleached pulp

Footnotes:

(a) As sulfur. Based on worst-case engineering estimate from AMEC Forest Industry Consulting.
(b) Maximum hourly rate based on existing permit limit; maximum daily rate based on proposed limitation.
(c) SO_2 calculated as potential sulfur emissions times two, based on MW sulfur = 32 and MW of SO2 = 64.
(d) No removal of SO_2 in either boiler is assumed.
(e) Based on 5 ppmvd @ 10% O_2 and actual flow rate from stack test data (135,400 dscfm @ 10% O_2).
(f) Based on 5 ppmvd @ 10% O_2 and actual flow rate from stack test data (147,200 dscfm @ 10% O_2).
(g) Assumes SAM emissions are equivalent to 4% of SO_2 emissions, based on AP-42 for combustion sources.

Attachment GP-EU1-G8b. Estimated Maximum Annual TRS, SO_2 and SAM Emissions From Power Boilers Due to HVLC DNCG Stream Combustion Only, Georgia-Pacific Palatka

Source	Uncontrolled TRS Emissions [a] (lb S/ton ADUP)	Pulp Production Rate [b] (tons/yr ADUP)	Maximum SO_2 Emission Rate [d] (TPY)	Maximum TRS Emission Rate (TPY)	Maximum SAM Emission Rate [g] (TPY)
SCENARIO 1: NO. 4 COMBINATION BOILER 100% UPTIME					
HVLC DNCGs--No. 4 Combination Boiler @ 100%	**0.35**	675,250	236.3	15.69 [e]	9.45
SCENARIO 2: NO. 5 POWER BOILER 100% UPTIME					
HVLC DNCGs--No. 5 Power Boiler @ 100%	**0.35**	675,250	236.3	17.06 [f]	9.45

Notes:
- NCG = noncondensable gases
- DNCG= dilute NCG
- S= sulfur
- SO_2 = sulfur dioxide
- HVLC = high volume, low concentration
- ADUP= air-dried unbleached pulp
- TRS = total reduced sulfur

Footnotes:
(a) As sulfur. Based on worst-case engineering estimate from AMEC Forest Industry Consulting.
(b) Based on 1,850 tons/day ADUP @ 365 days/yr.
(c) SO_2 calculated as potential sulfur emissions times two, based on MW sulfur = 32 and MW of SO2 = 64.
(d) No removal of SO_2 in either boiler is assumed.
(e) Based on 5 ppmvd @ 10% O_2 and actual flow rate from stack test data (135,400 dscfm @ 10% O_2).
(f) Based on 5 ppmvd @ 10% O_2 and actual flow rate from stack test data (147,200 dscfm @ 10% O_2).
(g) Assumes SAM emissions are equivalent to 4% of SO_2 emissions, based on AP-42 for combustion sources.

ATTACHMENT L (Q-9)

Updated Tables 2-1, 2-3, and 3-3 – No. 4 CB PSD

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

Source Description	EU ID	Pollutant Emission Rate (TPY) SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluorides
No. 4 Power Boiler												
2001 Actual Emissions	014	296.2	36.2	3.85	19.8	17.2 [l]	0.22	--	13.0 [a,m]	0.0092	0.000087 [a,g]	0.029 [a,g]
2002 Actual Emissions		245.0	31.1	3.31	16.5	14.3	0.19	--	10.8 [a,m]	0.0010	0.000075 [a,g]	0.025 [a,g]
Average Actual Emissions		**270.6**	**33.6**	**3.58**	**18.1**	**15.7**	**0.20**	--	**11.9**	**0.005**	**0.000081**	**0.027**
No. 4 Combination Boiler	016	--	--	--	--	--	--	--	--	--	--	--
2004 Actual Emissions												
--Fuel Oil Usage		763.6 [j]	102.3	10.9	12.4 [c]	7.81 [e]	0.61	--	33.6 [a,m]	0.0033 [o]	0.00025 [h]	0.081 [a,h]
--Wood/Bark Usage		33.8	324.2 [b]	810.6	121.6 [d]	90.0 [f]	23.0 [k]	--	1.49 [a,m]	0.065 [p]	0.0047 [i]	--
--NCG/SOG Burning		281.9	19.1	--	--	--	--	0.47 [n]	12.4 [a,m]	--	--	--
--Total (Without NCGs/SOG)		**797.4**	**426.5**	**821.5**	**134.0**	**97.8**	**23.6**	**0.0**	**35.1**	**0.07**	**0.005**	**0.08**
2005 Actual Emissions												
--Fuel Oil Usage		828.3 [j]	108.9	11.6	13.3 [c]	8.37 [e]	0.65	--	36.4 [m]	0.0035 [o]	0.00026 [h]	0.086 [a,h]
--Wood/Bark Usage		30.3	291.0 [b]	727.4	50.9 [d]	37.7 [f]	20.6 [k]	--	1.33 [m]	0.058 [p]	0.0042 [i]	--
--NCG/SOG Burning		279.5	16.5	--	--	--	--	0.47 [n]	12.3 [m]	--	--	--
--Total (Without NCGs/SOG)		**858.6**	**399.9**	**739.0**	**64.2**	**46.1**	**21.3**	**0.0**	**37.8**	**0.06**	**0.005**	**0.09**
Average Actual Emissions												
--Total (Without NCGs/SOG)		**828.0**	**413.2**	**780.3**	**99.1**	**71.9**	**22.4**	**0.0**	**36.4**	**0.065**	**0.0047**	**0.084**

TPY = tons per year.

Footnotes:

[a] Not reported in AOR.

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

[c] PM based on the actual fuel oil usage (4,351,660 gal/yr in 2004 and 4,633,380 gal/yr in 2005), heat content of fuel oil (150,000 Btu/gal), and average of 2003-2005 stack test data (0.038 lb/MMBtu).

[d] PM based on the actual wood/bark burned (300,219 TPY in 2004 and 269,420 TPY in 2005), heat content of wood/bark (4,500 Btu/lb), and actual stack test data (0.09 lb/MMBtu on 1/8/04 and 0.042 lb/MMBtu on 8/18/05).

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

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

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

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

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

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

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

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

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

[n] Based on maximum permitted rate for TRS.

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

[p] Lead emissions based on actual wood/bark burned (300,219 TPY in 2004 and 269,420 TPY in 2005) and emission factors from AP-42 Table 1.6-4 (Pb = 4.8E-05 lb/MMBtu converted to 4.3E-04 lb/ton wood/bark by multiplying by 9 MMBtu/ton

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

TABLE 2-3

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

Source Description	EU ID	Pollutant Emission Rate (TPY)										
		SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluoride
2004 Actual Emissions [c]												
No. 4 Combination Boiler [b]	016	797.4	426.5	821.5	134.0	97.8	23.6	--	35.1	0.068	5.0E-03	0.081
No. 4 Lime Kiln	017	0.04	129.5	5.4	30.4	29.9	2.3	2.3	0.0017	0.160	--	--
No. 4 Recovery Boiler	018	17.4	464.7	1,285.0	213.0	159.8	1.2	8.9	2.4	0.012	6.7E-05	--
No. 4 Smelt Dissolving Tank	019	27.2	56.2	9.3	41.2	37.1	93.1	6.1	--	0.010	6.7E-05	--
Black Liquor/Green Liquor Tanks	042	--	--	--	--	--	9.6	3.0	--	--	--	--
Caustic Area	042	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Bark Handling System (March 2005) [a]	--	--	--	--	14.6	10.6	175.4	--	--	--	--	--
2005 Actual Emissions [c]												
No. 4 Combination Boiler [b]	016	858.6	399.9	739.0	64.2	46.1	21.3	--	37.8	0.062	4.5E-03	0.086
No. 4 Lime Kiln	017	0.04	73.3	8.2	72.1	70.9	2.6	2.8	0.0018	0.160	--	--
No. 4 Recovery Boiler	018	12.0	481.7	1,213.5	56.3	42.2	17.8	13.7	0.53	0.012	6.9E-05	--
No. 4 Smelt Dissolving Tank	019	28.2	58.0	9.5	28.6	25.7	95.7	4.1	--	0.010	6.9E-05	--
Black Liquor/Green Liquor Tanks	042	--	--	--	--	--	9.7	3.0	--	--	--	--
Caustic Area	042	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Bark Handling System (March 2005) [a]	--	--	--	--	14.6	10.6	175.4	--	--	--	--	--
Average 2004 & 2005 Actual Emissions												
No. 4 Combination Boiler	016	828.0	413.2	780.3	99.1	71.9	22.4	--	36.4	0.065	4.7E-03	0.084
No. 4 Lime Kiln	017	0.04	101.4	6.8	51.3	50.4	2.5	2.6	0.0018	0.160	--	--
No. 4 Recovery Boiler	018	14.7	473.2	1,249.3	134.7	101.0	9.5	11.3	1.47	0.012	6.8E-05	--
No. 4 Smelt Dissolving Tank	019	27.7	57.1	9.4	34.9	31.4	94.4	5.1	--	0.010	6.8E-05	--
Black Liquor/Green Liquor Tanks	042	--	--	--	--	--	9.7	3.0	--	--	--	--
Caustic Area	042	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Bark Handling System (March 2005)	--	--	--	--	14.6	10.6	175.4	--	--	--	--	--

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

[b] See Table 2-1.

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

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

Source Description	Pollutant Emission Rate (TPY) SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluoride
Future Potential Emissions[a]											
No. 4 Combination Boiler - 2.35% S	1,023.7	496.5	1,010.5	80.8	59.8	34.4	--	45.0	0.097	0.0071	0.095
No. 4 Lime Kiln: annual: 20 ppmvd TRS	40.0	297.4	71.5	130.2	128.0	41.4	25.1	1.8	0.25	--	--
No. 4 Recovery Boiler	153.9	738.1	2,245.6	331.1	248.3	92.0	34.2	15.9	0.014	8.3E-05	--
No. 4 Smelt Dissolving Tank [b]	33.7	69.6	11.4	55.2	49.7	115.0	14.9	--	0.013	8.3E-05	--
Black Liquor/Green Liquor Tanks [b]	--	--	--	--	--	14.0	3.7	--	--	--	--
Caustic Area [b]	--	--	--	2.6	2.6	18.9	5.8	--	--	--	--
Other Projects											
Bark Handling System [c]	--	--	--	22.8	13.9	475.8	--	--	--	--	--
Total- Future Potential	**1,251.3**	**1,601.6**	**3,339.0**	**622.7**	**502.3**	**791.5**	**83.8**	**62.7**	**0.37**	**0.0072**	**0.095**
Past Actual Emissions [d]											
No. 4 Combination Boiler	828.0	413.2	780.3	99.1	71.9	22.4	--	36.4	0.065	0.0047	0.084
No. 4 Lime Kiln	0.04	101.4	6.8	51.3	50.4	2.5	2.6	0.0018	0.16	--	--
No. 4 Recovery Boiler	14.7	473.2	1,249.3	134.7	101.0	9.5	11.3	1.5	0.012	6.8E-05	--
No. 4 Smelt Dissolving Tank [b]	27.7	57.1	9.4	34.9	31.4	94.4	5.1	--	0.010	6.8E-05	--
Black Liquor/Green Liquor Tanks [b]	--	--	--	--	--	9.7	3.0	--	--	--	--
Caustic Area [b]	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Other Projects											
Bark Handling System [c]	--	--	--	14.6	10.6	175.4	--	--	--	--	--
Total- Past Actual	**870.4**	**1,044.9**	**2,045.7**	**336.2**	**267.0**	**326.4**	**25.9**	**37.9**	**0.25**	**0.0049**	**0.084**
Increase Due to Project	**380.9**	**556.7**	**1,293.3**	**286.5**	**235.3**	**465.1**	**57.8**	**24.8**	**0.13**	**0.0024**	**0.011**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0.6	0.1	3.0
Netting Triggered?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	No	No	No
CONTEMPORANEOUS EMISSION CHANGES											
MACT I Compliance Project (9/00) (Permit nos. 1070005-007-AC and -017-AC) - startup 2002											
--Increase Due to New Thermal Oxidizer	109.7	151.4	8.8	30.7	30.7	9.1	0.89	7.7	--	--	--
--Increase Due to Modified No. 4 Comb. Boiler	548.7	37.8	--	--	--	--	0.47	21.9	--	--	--
--Increase Due to BSW System w/Condensate Treatment	--	--	--	--	--	48.6	58.7	--	--	--	--
--Decrease Due to Existing Thermal Oxidizer	-749.8	-49.5	-0.3	-20.6	-20.6	-3.2	-0.3	-26.9	--	--	--
--Decrease Due to Existing BSW System w/o Condensate Treatment	--	--	--	--	--	-52.1	-62.9	--	--	--	--
--Net Change	-91.4	139.7 [e]	8.5	10.1	10.1	2.4	-3.14	2.7	--	--	--
New Package Boiler (9/02) (Permit No. 1070005-018-AC) - startup Oct. 2002											
--Increase Due to New Package Boiler (EU 044)	0.1	39.4	16.5	1.5	1.5	1.1	--	--	f	f	f
--Decrease from old No. 6 Package Boiler	-0.07	-9.2	-2.1	-0.15	-0.15	--	--	--	f	f	f
--Net Change	0.03	30.20	14.40	1.35	1.35	1.1	--	--	f	f	f
Brown Stock Washer and Oxygen Delignification System (7/04) (Permit No. 1070005-024-AC) - startup Feb. 2006											
--Increase Due to No. 4 Comb. Boiler/No. 5 Power Boiler	236.3	--	0.3	--	--	4.0	17.1	9.5	--	--	--
--Increase Due to Pulp Storage Tanks	--	--	--	--	--	63.1	9.6	--	--	--	--
--Decrease from existing BSW System, BL Filter, etc.	--	--	--	--	--	-128.5	-77.1	--	--	--	--
--Net Change	236.3 [e]	--	0.3	--	--	-61.4	-50.4	9.5	--	--	--
No. 4 Power Boiler Shutdown (Sep. 2003)	-270.6	-33.6	-3.6	-18.1	-15.7	-0.2	--	-11.9	-0.005	-0.000081	-0.027
Total Contemporaneous Emission Changes	**-362.0**	**-3.4**	**19.6**	**-6.7**	**-4.3**	**-58.10**	**-53.5**	**0.3**	**-0.005**	**-0.000081**	**-0.027**
TOTAL NET CHANGE	**18.9**	**553.3**	**1,312.9**	**279.8**	**231.0**	**407.0**	**4.3**	**25.1**	**0.12**	**0.0023**	**-0.015**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0.6	0.1	3.0
PSD REVIEW TRIGGERED?	No	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	No	**Yes**	No	No	No

Notes:

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

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

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

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

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

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

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Jeb Bush
Governor

Department of Environmental Protection

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

Colleen M. Castille
Secretary

August 17, 2006

CERTIFIED MAIL – Return Receipt Requested

Mr. Keith Wahoske
Vice President – Palatka Operations
Georgia-Pacific
Palatka Mill
P.O. Box 919
Palatka, Florida 32178-0919

RE: Modification to the Nos. 4 Combination Boiler, Lime Kiln and Recovery Boiler
Project No.: 1070005-038-AC/PSD-FL-380

Dear Mr. Wahoske:

On July 18, 2006, the Department received a request to modify the Nos. 4 Combination Boiler, Lime Kiln and Recovery Boiler. Based on our review of the proposed project, we have determined that the following additional information is needed in order to continue processing this application package. Please provide all assumptions, calculations, and reference material(s), that are used or reflected in any of your responses to the following issues:

No. 4 Combination Boiler (CB).

1. In Attachment GP-EU1-F1.8, specifically in Section 1.A., LVHC NCGs, a claim of "at least 60%" sulfur removal efficiency in the pre-scrubber is made. How was this minimum efficiency established? Do you have any performance tests/documentation to support this claim? Please provide any test reports/documentation to support this efficiency removal claim.

2. In Attachment GP-EU1-F1.8, specifically Sections 1.A, B. and D., provide documentation of the emission factors used, i.e., 378 lbs S/hr loading from the LVHC gas stream, 162 lbs S/hr from the SOG stream and 0.35 lbs S/hr from the DNCG stream, respectively.

3. In Attachment GP-EU1-F1.8, specifically Section 2, Maximum 24-hr SO_2 Emission Rate, what is the basis of the 2300 TPD ADUP pulp production rate used in the calculations? Has this level of production ever been achieved? If not, then identify equipment changes/modifications and/or replacements will have to be made in order to achieve this level of operation?

4. During a loss of bark feed and a switch to 100% fuel oil firing, do you plan, as a method of operation, to burn the DNCGs, NCGs and SOGs in the CB, or will they routed to the No. 5 Power Boiler (No. 5 PB) or some other emissions unit for destruction? Please explain and adjust any calculations that is/are appropriate.

5. For the annual SO_2 emissions calculations in Attachment GP-EU1-F1.8, what is the basis for the "20% utilization of the CB for the destruction of NCGs, SOGs and DNCGs"? Please explain and provide justification. Adjust any calculations that is/are appropriate. When in this mode, how are you demonstrating compliance with the TRS limit?

6. Is the thermal oxidizer, which is the primary destruction device for NCGs and SOGs, down 20% of the operational year? If so, please explain. In addition, provide the hours of operation and downtime for the thermal oxidizer for the last five years.

7. While the thermal oxidizer is operating, have you ever routed the NCGs and SOGs to the CB or another emissions unit for destruction? If yes, please explain.

8. When the CB is used as a backup control device for NCGs, SOGs, and DNCGs, how is compliance demonstrated? For the years that the CB has been used as a backup control device for the thermal incineration system, provide the number of hours of operation in this backup control mode and the percent of total operation of the CB in this backup control mode. Is the CB also the primary control device for DNCGs (see Page 2-8)? When the CB is used as the control device for NCGs, SOGs, and DNCGs, do the controlled emission levels comply with the NESHAP, 40 CFR 63, Subpart S?

9. Based on the exceptions listed in the PSD Report, Section 2.3.1., Past Actual Emissions, have you submitted a correction to the 2004 and 2005 AORs?

10. The Bark Hog project used a heating value for wet as-fired bark of 4500 Btu/lb. Yet for this project, the value of 4750 Btu/lb, wet and as-fired is being used. The permitted capacity of Btu/hr heat input to the CB was limited to 512.7 MMBtu/hr, based on "57 tons per hour carbonaceous fuel (bark/wood chips) with an average heating value of 4500 Btu/lb on a wet, as-fired basis". In this application, the requested heat input is 564 MMBtu/hr based on "59.4 TPH tons per hour carbonaceous fuel (bark/wood chips) with an average heating value of 4750 Btu/lb on a wet, as-fired basis". Please explain why you used a different heating value for the same material. Also, resubmit corrected pages as appropriate.

11. According to the application, the current permitted maximum heat input rate to the CB is 512.7 MMBtu/hour based on a 24-hour average. Based on a wood/bark heating value of 4750, this is equivalent to a maximum of 54 TPH and 1296 TPD of wood/bark firing. The application requests a maximum annual heat input rate of 4,042,127 MMBtu during any consecutive 12 months. The proposed physical changes (upgraded bark/wood delivery system, new air swept bark/wood feeders, new OFA system and modified combustion air supply, modified underfire air distribution, upgraded ash removal system, etc.) will allow the existing CB to achieve the above maximum heat input rates and wood/bark firing rates. Is this accurate?

12. For CO, NOx, SO_2, and VOC emissions: provide any emissions test data available for the CB; and, provide any emission test data available for other G-P boilers similar to the CB at the Palatka Mill.

13. See Attachment GP-EU1-I1, which is a process flow diagram for the CB.

a. This chart shows ash from the new mechanical dust collector being directed back to the CB and not the ash sluice tanks. Please explain.

b. This chart shows the exhaust from the CB directed to the new mechanical dust collector and then being split between the existing ESP for the CB and the existing ESP for the No. 5 PB. The application later indicates that the ESPs for the CB the No. 5 PB will be refurbished. The ESP for the No. 5 PB may be used as the 4th, 5th and 6th fields for the exhaust from the CB. If this happens, a new ESP will be installed for the No. 5 PB. In other words, the exhaust streams will never mix and there will only be one stack. Is this accurate? Provide additional details of the proposed configuration, cost of the proposed ESP work for the CB, cost of the proposed ESP work for the No. 5 PB (including new field), cost of the connecting ductwork, and the cost of a proposed new ESP for the No. 5 PB.

c. The Department is aware the G-P has filed a separate minor source air construction permit with the NED Office to install a new field on the No. 5 PB. The system is being designed for a much larger flue gas flow rate than is needed for the No. 5 PB. Has G-P made the decision to use the refurbished ESP for the No. 5 PB to control emissions from the CB? Isn't this project related to the PSD application for the CB? Please explain.

14. See Attachment GP-EU1-I3, which provides control equipment details for the CB.
   - o Details for the new mechanical dust collector indicate a maximum inlet flow rate of 280,000 acfm @ 700° F.
   - o Details for the refurbished ESP for the CB indicate a maximum inlet flow rate of 455,000 acfm @ 325° F.

   a. Is additional air being provided to cool the exhaust prior to the ESP?

   b. Identify the dscfm of exhaust from the CB, the dscfm of cooling air, and the total dscfm to the ESP.

   c. What is the design temperature for the ESP?

   d. Are new fans being installed to achieve this cooling and exhaust rate?

15. Why weren't past actual PM emissions simply based on previous stack test data? Does the boiler typically fire oil with wood/bark? At what rate? Are assumed control efficiencies reasonable based on the existing cyclone/ESP control system installed for this unit?

16. The application indicates that the current PM standard is 0.3 lb/MMBtu and requests a BACT limit of 0.04 lb/MMBtu. NESHAP DDDDD provisions establish a PM standard of 0.025 lb/MMBtu for new solid fuel-fired boilers. Table 5-1 of the application lists the PM/PM_{10} BACT determination for 34 recent projects for biomass-fired boilers. Of these, 17 projects have BACT determinations of 0.03 lb/MMBtu or less. Explain why the additional improvements described for the ESP(s) would not be able to achieve such a level of emissions for the CB.

17. The application indicates that new low-NOx burners (LNBs) will be installed to fire No. 6 fuel oil (2.35% sulfur content, by weight, max.). These burners will replace the same number of existing oil burners, will have the same heat input rate, will achieve a NOx emission standard of 0.27 lb/MMBtu, and will be restricted to firing no more than 5,100,000 gallons during any consecutive 12 months. The application also indicates that there are 6 oil guns. How many total oil burners are there? What is the generally acceptable range of NOx emissions for a burner to be considered a "low-NOx" burner? Provide the vendor specifications for both the CO and NOx emissions from the proposed new burners. Please explain the use of the "0.164" factor when estimating SO_2 emissions from oil firing. Is this a reasonable estimate of SO_2 emission from oil firing?

18. Describe the new equipment, controls, and improvements to the overfire air (OFA) system for the CB. Has (or will) computational fluid dynamic modeling be conducted to aid in the design of the OFA? Provide any vendor specifications available regarding emission levels before and after installation of the new OFA.

19. Does the CB currently have flue gas recirculation (FGR)? What is the maximum designed percent of FGR? Does the boiler operate at this rate? When was it installed?

20. As stated in the application, SNCR for several Florida biomass-fired boilers have achieved levels of up to 50% NOx reduction. Provide a revised cost effectiveness analysis assuming this level of control. Provide details for this specific boiler that causes problems related to an SNCR system and high control efficiencies.

21. Page 3-12 of the application states that NSPS Subpart Db could apply to the project to modify an oil and wood-fired boiler if there was an hourly increase in emissions. The conclusion is that this subpart does not apply because PM emissions will actually decrease for this unit. Provide a similar discussion for SO_2 and NOx emissions, which are also regulated by this subpart. Please correlate the discussion with that provided on Page 3-13 regarding SO_2 and NOx emissions.

22. Is the existing No. 4 Power Boiler currently shutdown? What is the date of last operation for this unit? Is this unit currently able to operate in its current condition? When will construction begin on the proposed PSD project?

23. In the section labeled "PSD Report", specifically page 2-7, next-to-last paragraph, you indicated that the No. 5 PB's modified ESP "may" be used by the CB's operation for additional control of particulate emissions. Based on this, please respond to the following issues:

a. Please describe what "may" means.

b. Are you planning to use the No. 5 PB's modified ESP to control particulate emissions from the CB's operation on a permanent basis? If not, please explain.

c. Which stack will be used on a permanent basis...the CB's or the No. 5 PB's....when the No. 5 PB's modified ESP is being utilized?

d. Since the No. 5 PB and its mass emissions will be impacted by the CB project, have the emissions of all affected pollutants been included in the modeling for the CB project, which includes the Nos. 4 RB and LK projects? Did you assess the potential impact of all of the pollutant emissions exiting the No. 5 PB's modified ESP and its associated stack?

e. What is the resultant flue gas volumetric flow rate in "dscfm @ 10% O_2" when the No. 5 PB's modified ESP is being utilized by the CB's operation?

f. List and describe all of the "methods of operation" for which the No. 5 PB's modified ESP will be used by the CB's operation, and this listing should include all of the fuels (100% fuel oil to percentages of fuel oil and bark) used by the No. 5 PB and the CB.

g. Regarding the No. 5 PB's modified ESP as an extended control device of the CB's operation, what is the expected control efficiency for each pollutant? Provide all assumptions and calculations.

h. Will the pollutant emissions of the No. 5 PB's modified ESP increase due to this project?

i. Will the inlet loading to the No. 5 PB's modified ESP increase due to this project?

j. Will there be an increase in the flue gas volumetric flow rate through the No. 5 PB's modified ESP due to this project? If so, please provide the assumptions and calculations for the potential pollutant emissions due to this increase in flow rate.

k. For the PB, what is the volumetric flow rate of the modified ESP in "dscfm @ 10% O_2"? Based on the RAI response letter to the Northeast District dated June 29, 2006, regarding an application to modify the No. 5 PB's existing ESP, the design flow rate for the No. 5 PB's modified ESP was stated as 455,000 acfm. Since the original design flow rate was 231,500 acfm, and your response in Response #3 was that there will be no change to the existing ESP's fans, ducts, etc., then please explain how the modified ESP's flow rate will be 455,000 acfm without some fan and/or physical modification? Please provide any assumptions and calculations.

l. Since the CB's TRS allowable limit is 5 ppmvd @ 10% O_2, the current potential mass emissions of 3.6 lbs/hr and 15.7 TPY are based on a volumetric flow rate of 135,400 dscfm. Unless the No. 5 PB's volumetric flow rate, in "dscfm @ 10% O_2", is the same as the existing CB's dscfm flow rate, then the potential mass emissions of TRS will be increased when utilizing the No. 5 PB's modified ESP and appears to implicate that the net TRS mass emissions will be greater than significant and, therefore, subject to PSD NSR preconstruction review and BACT. If so, please submit the appropriate material and determination related to this.

m. In the PCP project for the burning of SOGs, NCGs and DNCGs, were the resultant SO_2 emissions evaluated exiting the Thermal Oxidizer and its backup, the CB? Based on the current proposal, this evaluation should be conducted if the No. 5 PB's modified ESP is going to be utilized by the CB's operations and SOGs, NCGs and DNCGs are being incinerated in the CB. If this was not done, please do so to provide reasonable assurance that there is no NAAQS nor increment violations.

n. It appears that the No. 5 PB's ESP modification and the recent application submittal for modifications to the Nos. 4 CB, RB and LK are related, i.e., the No. 5 PB's modified ESP will become a particulate control device for the CB's operation. As such, why wasn't the No. 5 PB's ESP modification and any appropriate changes, including impacts, modeling and potentially BACT, included in this project?

24. In the netting table, why did you not include any past and future TRS mass emissions from the CB, since it is the back-up control device for SOGs and NCGs and the primary control device for DNCGs, and it has an allowable emissions limit of 5 ppmvd @ 10% O_2? It should at least include the "20% utilization factor" requested and depicted in Attachment GP-EU1-F1.8. Was the CB used during CY 2004 and 2005 for the incineration of these gases? Provide the dates and amount of time it was utilized for this purpose during these years and make the calculations and appropriate adjustments to the netting table, Table 1, Past Actuals. Also, see Issue No. 5, above.

25. In the application, Section H. Continuous Monitor Information, there was no pages completed, yet the requirements for continuous emissions monitoring of TRS emissions pursuant to Rule 62-296.404(3)(f) and (5)(c), F.A.C., are applicable. Have you installed the devices to continuously monitor temperature at the point of combustion and oxygen pursuant to the requirements? If not, please explain. If so, please complete the appropriate application pages and submit.

26. In Attachment GP-EU1-I3, Detailed Description of Control Equipment, specifically for the No. 5 PB's ESP, the control efficiency is listed as 99.5% for particulate matter. Is this accurate? If not, please explain, correct and resubmit the document.

27. Please identify any other emissions units/activities that will be affected upstream and downstream by the increase in production and steam output due to the proposed modification of the CB. If any, please include in the analysis any increases in production and associated pollutant emissions, including any collateral emission changes and increases (NCG's TRS to SO_2, etc.) for these emissions units/activities.

No. 4 Lime Kiln (LK).

28. For the LK, provide the actual venturi scrubber pressure differential for each of the particulate matter emissions tests provided with the application (1995 – 2005).

29. The proposed BACT emissions standards in Table E-7 do not reflect the proposed BACT standards in the DEP application form nor the annual emissions used in the netting analysis. Please revise accordingly.

No. 4 Recovery Boiler (RB).

30. For the RB, the application proposes the following CO limits: 800 ppmvd @ 8% oxygen (3-hour average) and 400 ppmvd @ 8% oxygen (24-hour average). The application also reflects G-P's agreement to install a CO CEMS. Please verify the averaging periods.

31. For the RB, provide a discussion on the fraction of PM_{10} emissions of the PM emissions. This appears different than previous submittals.

Nos. 4 LK, RB and Smelt Dissolving Tank.

32. For all applicable units, please verify that past actual emissions for TRS and SO_2 were based on CEMS data and not test data. Please revise the calculation pages and the netting table appropriately.

Miscellaneous.

33. Where is the No. 5 PB located on the facility plot plan?

34. Due to the recent changes made regarding the Primary Responsible Official and Authorized Representative at the Georgia-Pacific's Palatka Mill, please have Mr. Wahoske sign, date and submit a completed application's "Owner/Authorized Representative Statement" page for each of the submitted applications, one for the CB and one for the combined LK and RB.

35. The Department did not receive the results of the SO_2 air dispersion modeling mentioned on page 4-2 of the RB's and LK's application. This modeling should include not only mill-wide SO_2 emissions due to the mill operating at the projected highest short-term limits, but all applicable nearby sources, and should include predicted impacts in both the PSD Class I and Class II areas. This modeling is required by Rule 62-212.300(1), F.A.C.

36. In Section 2.6.4 on page C-7 of the RB's and LK's application, the maximum receptor distance for the significant impact analyses is given as 4 km. Please provide the justification for this distance.

37. If the responses to any of the Department's comments above change the pollutant emission rates or stack configurations, these changes should be evaluated by the appropriate air dispersion modeling and the results provided to the Department.

38. Please provide a facility plot plan in AUTOCAD format, which shows the location of all stacks, buildings, fence lines and roads. This plot plan should have a scale and be in UTM coordinates.

39. If any response to the above issues affect the application submittal, please correct and/or change the application to reflect the additional analyses and submit.

Any additional comments from EPA and the U.S. Fish and Wildlife Service will be forwarded to you after we receive them. The Department will resume processing this application after receipt of the requested information. If you have any questions regarding this matter, please call Bruce Mitchell at (850)413-9198 or Cleve Holladay at (850)921-8986.

Sincerely,

Jeffrey F. Koerner

Jeffrey F. Koerner, P.E.
Permitting North Administrator
Bureau of Air Regulation

JFK/bm

cc: Gregg Worley, U.S. EPA, Region 4
John Bunyak, NPS
David Buff, P.E., GAI
Chris Kirts, NED
Myra J. Carpenter, G-PC

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Mr. Keith Wahoske, Vice President
Palatka Operations
Georgia-Pacific
Palatka Mill
Post Office Box 919
Palatka, Florida 32178-0919

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☐ Agent
☐ Addressee

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Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

July 19, 2006

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

RE: Georgia-Pacific Palatka Mill
Consolidated PSD Permit Application
1070005-038-AC, PSD-FL-380

Dear Mr. Worley:

Enclosed for your review and comment is a PSD permit application from Georgia-Pacific which consolidates previously submitted PSD applications for the Lime Kiln Shell (PSD-FL-345), the No. 4 Combination Boiler (PSD-FL-357) and the No. 4 Recovery Boiler (PSD-FL-367) at their Palatka Mill in Putnam County, Florida. This application replaces the previously submitted PSD applications which were withdrawn on July 11, 2006.

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

Sincerely,

Patty Adams

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

JFK/pa

Enclosure

cc: B. Mitchell

FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

July 19, 2006

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
P. O. Box 25287
Denver, Colorado 80225

RE: Georgia-Pacific Palatka Mill
Consolidated PSD Permit Application
1070005-038-AC, PSD-FL-380

Dear Mr. Bunyak:

Enclosed for your review and comment is a PSD permit application from Georgia-Pacific which consolidates previously submitted PSD applications for the Lime Kiln Shell (PSD-FL-345), the No. 4 Combination Boiler (PSD-FL-357) and the No. 4 Recovery Boiler (PSD-FL-367) at their Palatka Mill in Putnam County, Florida. This application replaces the previously submitted PSD applications which were withdrawn on July 11, 2006.

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

Sincerely,

Patty Adams

Jeffry F. Koerner, P.E., Administrator
North Permitting Section

JFK/pa

Enclosure

cc: B. Mitchell

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

To: DEP NORTHEAST DISTRICT OFFICE
MR. CHRIS KIRTS
7825 BAYMEADOWS WAY
AIR SECTION, SUITE 200B
JACKSONVILLE, FL 32256
UNITED STATES

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MR. CHRIS KIRTS
7825 BAYMEADOWS WAY
AIR SECTION, SUITE 200B
JACKSONVILLE, FL 32256
UNITED STATES

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12795 W. ALAMEDA PARKWAY
AIR DIVISION
LAKEWOOD, CO 80228
UNITED STATES

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MR. JOHN BUNYAK
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AIR DIVISION
LAKEWOOD, CO 80228
UNITED STATES

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To: U.S. EPA REGION 4
MR. GREGG M. WORLEY
61 FORSYTH STREET
AIR PERMITS SECTION
ATLANTA, GA 30303
UNITED STATES

POSTCODE: 30303

TEL: 404-562-9141

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Description: PSD-FL-380 app;PSD-FL-379 app; PSD-FL-377 response
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Atlanta, GA 30303
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Phone#: 404-562-9141

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

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Protection: Not Required
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Georgia-Pacific

Palatka Pulp and Paper Operations
Consumer Products Division

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

July 17, 2006

Mr. Jeffrey Koerner, P.E., Permitting North Administrator
Bureau of Air Regulation
Florida Department of Environmental Protection
Division of Air Resource Management
Twin Towers Office Building
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

RECEIVED
JUL 18 2006
BUREAU OF AIR REGULATION

Re: **Georgia-Pacific Palatka Mill - PSD Permit Applications – Consolidated Package**

Lime Kiln (LK) Shell	Project No.: 1070005-030-AC/PSD-FL-345
#4 Combination Boiler (CB)	Project No.: 1070005-033-AC/PSD-FL-357
#4 Recovery Boiler (RB)	Project No.: 1070005-035-AC/PSD-FL-367

Dear Mr. Koerner:

Enclosed are 7 complete copies of the consolidated package containing the #4 Recovery Boiler / #4 Lime Kiln Shell PSD application and the #4 Combination Boiler PSD Application. This package represents the consolidation of the above referenced PSD Applications sent to your department in 2004 and 2005 and subsequently withdrawn on July 11, 2006. Also included is a letter from Mr. Dave Buff, P.E. that summarizes how the projects were aggregated and the impacts on allowable emissions. Attached to Mr. Buff's letter is the updated netting table for these projects. To aid your review and understanding of this package, attached to this letter are the introduction sections of both applications.

We are submitting this package per discussions with you and your staff. Because this submittal is to consolidate and aggregate the three projects for which application fees were paid and that have already been reviewed by the Department, no additional application fee was to be required and none is enclosed. During the past year GP and DEP had settled on several limits for the #4 Recovery Boiler and the #4 Lime Kiln. GP intended to minimize any changes contained in this package compared to previous discussions with the Department. However, with the removal of the #4 Lime Kiln Petroleum Coke (Petcoke) fuel project, several changes to emissions limits are warranted. In order to facilitate the Department's review, and to avoid misunderstandings that might delay the issuance of a final PSD Permit, the updates contained in this package are listed below.

For the Recovery Boiler Project, GP had proposed a reduction in the mill wide Sulfur-in-fuel limitation from 2.35% Sulfur to 2.1% Sulfur. The elimination of the impact of the Petcoke project has allowed GP to maintain the current 2.35%S limit. The short term (24-hour) emission limit for SO2 has been changed from 37.5 ppm to 100 ppm based on the results of new ambient air modeling. During discussions between GP and DEP in early 2006, the possibility of increasing this short term limit was discussed and tentatively accepted as long as modeling supported the revised limit and the modeling results were submitted to the Department. The appropriate modeling has been completed and is included herein.

For the Lime Kiln Shell Project GP in July 2005 GP had agreed to a TRS limit of 17 ppm (12-hour average). However, with revised TRS information and modeling, the current limit of 20 ppm is proposed to remain the same.

Because some of the work included in this package could be started and finished this year, we are very interested in meeting with you and your staff to resolve any issues that could delay the processing of the permit.

If you have any questions please call me at (386) 329-0918.

Sincerely,

Myra J. Carpenter

Myra J. Carpenter
Environmental Superintendent

cc: T. Champion, S.D. Matchett, T. Wyles, E. Jamro
Mr. D. Buff – Golder Asso.

1.0 INTRODUCTION

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

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

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

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

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

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

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

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

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

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

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

1. Ambient monitoring analysis, unless the net increase in emissions due to the modification causes impacts that are below specified significant impact levels;

2. Application of best available control technology (BACT) for each new or modified emissions unit, for each pollutant subject to PSD review;

3. Air quality impact analysis, unless the net increase in emissions due to the modification causes impacts which are below specified significant impact levels; and

4. Additional impact analysis (*e.g.,* impact on soils, vegetation, visibility), including impacts on PSD Class I areas.

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

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

3. INTRODUCTION

3.1 Facility Location and Description

Georgia-Pacific Corporation (GP) operates an unbleached and bleached Kraft pulp and paper Mill in Palatka, Florida (Putnam County). Processes and systems at the Mill include a batch digester system, multiple effect evaporator (MEE) system, condensate stripper system, recovery boiler and smelt dissolving tanks, lime kiln, tall oil plant, utilities, bleach plant, chlorine dioxide plant, paper machines and converting operations used to produce finished paper products from virgin wood.

The Mill site is located north of County Road 216 and west of U.S. Highway 17. The approximate Universal Trans Mercator (UTM) coordinates are 434.0 kilometers (km) east and 3283.4 km north in Zone 17. The Mill location is shown on a United States Geological Survey (USGS) topographic map in Figure 3-1. A plot plan of the facility is included as Figure 3-2. Figure 3-3 is a simplified process flow diagram for the entire facility.

While equipment capacities may vary throughout the Mill, the current permitted allowable production level is 118 tons per hour of air dried unbleached pulp (ADUP) and 1,850 ADUP per day as a maximum monthly average.

Putnam County has been designated by the U.S. Environmental Protection Agency (US EPA) as in attainment or unclassified for all criteria pollutants. The existing Mill is classified as a major stationary source under Prevention of Significant Deterioration (PSD) and Clean Air Act Title V definitions since it has the potential-to-emit more than 100 tons per year (tpy) of at least one regulated air pollutant. The initial Title V permit was issued to the Palatka Mill on October 30, 2000. The Mill is currently operating under Title V Permit 1070005-034-AV, issued in December 2005.

3.2 Project Description

<u>No. 4 Recovery Boiler</u>

The No. 4 Recovery Boiler was originally constructed in 1974 and started up in 1975. The current permitted capacity of the boiler is 210,000 pounds (lbs) per hour of black liquor solids (BLS) and 5.04 million pounds (MM lbs) of BLS per day. The boiler is currently permitted to combust natural gas, No. 6 fuel oil with a sulfur content not to exceed 2.35% by weight, and on-spec used oil as start-up fuels. The recovery boiler, which is equipped with an electrostatic precipitator (ESP) for particulate matter control, has been subjected to PSD review twice in the past – once in 1991 and a second time in 1995.

In 1991, the entire bottom of the recovery boiler was replaced and modifications were made to the combustion air system. The changes to the combustion air system resulted in an increased throughput from 189,000 lbs BLS per hour to the current permitted capacity of 210,000 lbs BLS per hour.

The project in 1995 involved the addition of sixteen (16) screen tube banks in the boiler. One of the benefits from the project was a decrease in the flue gas temperature in certain sections of the boiler, which reduced tube abrasion, resulting in an improvement in performance and reduced maintenance downtime. The installation of the additional tubes also had the potential to increase BLS throughput and steam production by 4% and 30,000 pounds per hour, respectively. While an actual throughput increase was anticipated, the Mill did not expect, nor request, an increase in the permitted capacity of the unit (210,000 lbs/hour and 5.04 MM lbs BLS/day).

The Mill is now proposing to implement several projects for the No. 4 Recovery Boiler and associated evaporators. These projects, described in more detail below, include (1) extensive replacement of tubes, (2) replacement or changes to the air system, (3) addition of a crystallizer, to increase BLS concentration and (4) miscellaneous changes (*i.e.*, baffles, heat exchanger, piping, etc.) to the concentrators.

Tube Replacements

The Mill plans to replace a large percentage of the tubes in the No. 4 Recovery Boiler. This includes tubes in the superheater, economizer, and generating banks of the boiler. This major tube work is estimated to commence in May 2007 and conclude in 2008. The total cost of this work is estimated to be in the range of $24 million. Many of the tubes to be replaced are originals that have been in place since the boiler was constructed in the mid-1970s. Because of the scope and cost of the project, and in light of continuing uncertainty in the law as to what is "routine", GP decided not to pursue an exemption for this work as "routine maintenance, repair, and replacement." The preliminary scope for the tube replacements, although subject to change, is presented in Table 3-1.

Table 3-1. Preliminary Scope for Tube Maintenance on No. 4 Recovery Boiler

Boiler Section	Approximate Number of Tubes Involved	Affected Area/ Total Tube Area in Boiler (Percent)	Comments
Superheater	3,500	37.1	Most tubes are original. Three tubes have failed under pressure in the past 18 months.
Economizer	1,700	23.6	Tubes are original. Five tubes have failed under pressure in the past 26 months. Numerous tubes are plugged at both ends from previous failures.
Generating Bank	2,100	16.9	Tubes are original to boiler.
Floor	130	1.2	All but 14 tubes are original to boiler.

Combustion Air System

Although still in the preliminary engineering phase, the Mill is also considering replacement of, or changes to, the combustion air system for the boiler. The objective of this part of the project is to lower peak furnace exit gas temperature and velocity into the superheater in an effort to reduce the potential for erosion and pluggage of the superheater in the future. The new air system is also expected to reduce carry over and fouling in the boiler convection banks. Through the staging of air, it is anticipated that emissions of some pollutants (*e.g.*, total reduced sulfur (TRS) compounds and carbon monoxide (CO)) will be more consistently controlled and/or reduced). At the same time, by reducing CO and increasing boiler efficiency, nitrogen oxide (NO_x) emissions are expected to increase slightly. To avoid the slight increase in NO_x emissions, the Mill plans to install a fourth level of combustion air to the boiler. The Mill is in the process of receiving vendor quotations for this work, including suggested scope. As such, the exact scope of this work is not available at this time. The current cost estimate is less than $2 million.

Crystallizer

A third project involves a change to the black liquor evaporation system (No. 4 Evaporator Set). This change will increase the solids concentration of the black liquor to the recovery boiler from 65 percent solids to approximately 75 percent solids. When the new system is operational, the liquor from the concentrator will pass through a crystallizer vessel to raise the temperature of the liquor. The liquor will then enter a storage/flash tank at lower pressure where the moisture will "flash off". The "flash" vapors will then be routed to the existing evaporator system and collected as part of the existing non-condensable gas (NCG) collection system. The purpose of the project is to increase boiler efficiency by reducing the amount of water entering the boiler with the liquor solids. The increase in solids will improve the efficiency of the boiler for steam production per pound of BLS, thus reducing the amount of steam produced from oil firing in the other boilers. The estimated cost of this work is in the range of $5 to $6 million.

Concentrators

Finally, the Mill is considering the removal of some internal baffles and resizing some downcomer piping in the existing concentrators. The unit currently has scaling problems, leading to frequent "boil outs". The proposed changes will improve liquor circulation and increase velocity through the tubes, which should reduce scaling and fouling. This will increase the time between "boil outs". In addition, an external heat exchanger will be added to the existing concentrators to preheat the liquor with steam prior to entry into the concentrators. This will allow for increased evaporation, providing for a capability that more closely matches the capacity of the recovery boiler.

No. 4 Lime Kiln

The No. 4 Lime Kiln was constructed in 1975 and started up in 1976. The permitted input capacity of this unit is 82,986 pounds per hour of calcium carbonate and inert materials (24-hr block average). This equates to 19.44 tons per hour of calcium oxide produced by the kiln. The kiln uses a venturi scrubber to control particulate matter emissions. This unit fires No. 6 fuel oil with a maximum sulfur content of 2.35% (by weight).

The Mill needs to replace a major section of the No. 4 Lime Kiln shell. In November 2003, the Mill experienced a near catastrophic failure of the kiln shell. The kiln had cracks all the way through the shell in several different areas of the "hot end". The failure occurred due to metal fatigue and crystallization, cooler design, and shell age. The failure occurred underneath the cooler tubes, which is causing excessive stress on the kiln shell. The original metal thickness was 1 7/8". The repairs made were for temporary use only since the only material available at the time of failure was 1" thick steel plate. The kiln also has a history of limited brick life due to shell deformation in the same area. The November 2003 outage resulted in an unbudgeted expenditure of $639,200 for maintenance repairs and purchased chemicals.

In February 2006, a similar failure occurred in the same location on the lime kiln shell. The crack completely penetrated the shell and ran continuously around 70% of the circumference. The resulting 10-day emergency shutdown and repair cost $2.5 million. Based on testing and evaluation from the original equipment manufacturer, the failure is expected to recur sometime in the future. The shell must be capable of handling in excess of 95,000 pounds from Pier #1 to the end of the shell (55,000 pounds of weight from the dam and lining; 4,000 pounds for each of the ten (10) cooler tubes). The current hot end shell thickness is inadequate to reliably handle this weight load.

An equipment vendor has recommended that the Mill replace 61 feet of the "hot end" kiln shell and refractory and all ten (10) coolers. The new coolers will have an improved mounting bracket design that will eliminate future stress cracking underneath the coolers. The total cost of this project is estimated at approximately $2 million, with approximately 75 percent of this total going toward the labor costs needed to complete the project. The Mill plans to complete this work during their spring outage in 2007.

0537627/0300/Intro

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL USA 32653
Telephone (352) 336-5600
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July 14, 2006

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JUL 18 2006
BUREAU OF AIR REGULATION

0537627

Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

Attention: Mr. Jeffrey Koerner, PE – Permitting North Administrator

**RE: GEORGIA-PACIFIC CORPORATION, PALATKA MILL
FACILITY I.D. NO. 1070005
PSD APPLICATION FOR NO. 4 RECOVERY BOILER, NO. 4 LIME KILN, AND NO. 4 COMBINATION BOILER PROJECTS**

Dear Mr. Koerner:

Georgia-Pacific Corporation (GP) operates an unbleached and bleached Kraft pulp and paper Mill in Palatka, Florida (Putnam County). In November 2005, the Mill submitted prevention of significant deterioration (PSD) applications for projects at the No. 4 Recovery Boiler and No. 4 Lime Kiln. The No. 4 Recovery Boiler application also reflected emission changes due to a planned project to allow the burning of petroleum coke in the Lime Kiln, as well as a project planned for the No. 4 Combination Boiler. The application was submitted using the past actual-to-future potential accounting methodology.

In light of the Mill's decision not to pursue the petroleum coke project at this time, Mr. Jeff Koerner of the Florida Department of Environmental Protection (FDEP) advised the Mill, in an email dated June 22, 2006, to withdraw these PSD applications and resubmit them, without the petroleum coke project, but along with an application for projects proposed for the No. 4 Combination Boiler. Accordingly, this PSD application is being submitted to cover the previously proposed projects for the No. 4 Recovery Boiler and the No. 4 Lime Kiln. In addition, the PSD application also covers projects being proposed for the No. 4 Combination Boiler. The PSD application information for the No. 4 Recovery Boiler and No. 4 Lime Kiln are contained in one volume, prepared by GP. The PSD application information for the No. 4 Combination Boiler is contained in a separate volume, prepared by Golder Associates Inc. (Golder).

As directed by the FDEP, emission increases for all three of these projects have been added to increases for other past and future projects, even though those projects are unrelated. In the interest of time and in order to avoid additional recordkeeping requirements that would be triggered if it were determined that there is a "reasonable possibility" that a PSD-significant increase will occur, GP has continued to conduct the PSD applicability analysis using the past actual-to-future potential accounting methodology.

GP continues to believe that this process of aggregating unrelated projects is inconsistent with past EPA guidance on this topic. For example, while actual emissions are expected to increase for the No. 4 Recovery Boiler, that is clearly not the case for the Lime Kiln. The Lime Kiln project, if reviewed on its own merit using a past actual-to-projected actual accounting methodology, would not trigger PSD review. Yet, GP has been forced to include it in this application, and the increases from the other projects cause this one to go through PSD review as well. GP does not consider the processing history of these applications to have established a precedent for future applications.

A summary table of the netting analysis is contained in Table 1 attached. The netting analysis includes the emission changes due to the Bark Handling System project (permit issued in November 2004). Also included are the contemporaneous emission increase and decreases occurring at the Mill in the last 5 years.

Following the more conservative accounting methodology, as discussed above, and taking into account net emission changes that have occurred during the last five years, PSD review is triggered for particulate matter (both total suspended particulate matter and particulate matter less than 10 micrometers in aerodynamic diameter), nitrogen oxides, carbon monoxide, sulfuric acid mist, and ozone (based on a significant increase in volatile organic compound emissions).

PSD review is not triggered for sulfur dioxide (SO_2), lead, total reduced sulfur (TRS) compounds, fluorides or mercury. The Mill is requesting voluntary, federally-enforceable restrictions for SO_2 and TRS in order to avoid PSD review for these pollutants.

The PSD permit application includes completed permit application forms, detailed emission calculations, and Best Available Control Technology (BACT) reviews. The air quality analysis is included in the application volume which addresses the No. 4 Recovery Boiler and the No. 4 Lime Kiln, as Attachment C.

GP understands that, based on correspondence with you, a single PSD permit will be issued by the Florida DEP to cover all three projects. GP also anticipates, given the fact that numerous requests for additional information (RAIs) have already been answered by GP on the Recovery Boiler and Lime Kiln applications and emission limits have been discussed extensively, that any additional questions concerning modifications to these sources should be minimal. If you have any questions regarding this matter, please contact Ms. Myra Carpenter at (386) 329-0918.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

Enclosures

DB/nav

cc: Myra J. Carpenter, GP
Ed Jamro, GP
Tammy Wyles, GP
Wayne Galler, GP
Scott Matchett, GP
C. Booth, Golder Associates Inc.

0537627/CB4-RB4-LK4 submit ltr 7-14-06.doc

TABLE 1
CONTEMPORANEOUS AND DEBOTTLENECKING EMISSIONS ANALYSIS AND PSD APPLICABILITY
NO. 4 COMBINATION BOILER, GP PALATKA

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

Notes:

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

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

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

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

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

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

TABLE 1-1
CONTEMPORANEOUS AND DEBOTTLENECKING EMISSIONS ANALYSIS AND PSD APPLICABILITY
INCORPORATION OF NO. 5 POWER BOILER FIRING 100% NATURAL GAS

Source Description	Pollutant Emission Rate (TPY)										
	SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluoride
Future Potential Emissions											
No. 4 Combination Boiler - 2.35% S [a]	835.5	496.5	1,010.5	80.8	59.8	34.4	---	36.8	0.097	0.0071	0.095
No. 5 Power Boiler firing 100% natural gas [h]	1.5	311.5	209.3	18.9	18.9	13.7	---	0.0	1.25E-03	6.48E-04	0
No. 4 Lime Kiln: annual: 20 ppmvd TRS	40.0	297.4	71.5	130.2	128.0	41.4	25.1	1.8	0.25	--	--
No. 4 Recovery Boiler [e]	153.9	738.1	2,245.6	331.1	248.3	92.0	34.2	15.9	0.014	8.3E-05	--
No. 4 Smelt Dissolving Tank [d]	33.7	69.6	11.4	55.2	49.7	115.0	14.9	--	0.013	8.3E-05	--
Black Liquor/Green Liquor Tanks [d]	--	--	--	--	--	14.0	3.7	--	--	--	--
Caustic Area [d]	--	--	--	2.6	2.6	18.9	5.8	--	--	--	--
Other Projects [g]											
Bark Handling System	--	--	--	22.8	13.9	475.8	--	--	--	--	--
Total- Future Potential	**1,064.6**	**1,913.1**	**3,548.3**	**641.7**	**521.3**	**805.2**	**83.7**	**54.5**	**0.38**	**0.0079**	**0.095**
Past Actual Emissions [f]											
No. 5 Power Boiler (2004-2005 data) [h]	3,316.4	459.6	48.9	193.6	166.5	2.7	---	145.9	0.015	0.0011	0.365
No. 4 Combination Boiler [b]	820.4	413.2	780.3	99.2	71.9	22.4	--	36.1	0.065	0.0047	0.084
No. 4 Lime Kiln	0.04	101.4	6.8	51.3	50.4	2.5	2.6	0.0018	0.16	--	--
Bark Handling System	--	--	--	14.6	10.6	175.4	--	--	--	--	--
No. 4 Recovery Boiler	14.7	473.2	1,249.3	134.7	101.0	9.5	11.3	1.50	0.012	6.8E-05	--
No. 4 Smelt Dissolving Tank [d]	27.7	57.1	9.4	34.9	31.4	94.4	5.1	--	0.010	6.8E-05	--
Black Liquor/Green Liquor Tanks [d]	--	--	--	--	--	9.7	3.0	--	--	--	--
Caustic Area [d]	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Total- Past Actual	**4,179.2**	**1,504.5**	**2,094.7**	**530.0**	**433.5**	**329.2**	**26.0**	**183.5**	**0.26**	**0.0059**	**0.449**
Increase Due to Project	**-3,114.6**	**408.6**	**1,453.7**	**111.7**	**87.7**	**476.0**	**57.7**	**-129.1**	**0.11**	**0.0020**	**-0.354**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0.6	0.1	3.0
Netting Triggered?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	No	No	No
CONTEMPORANEOUS EMISSION CHANGES											
MACT I Compliance Project (9/00) (Permit nos. 1070005-007-AC and -017-AC) - startup 2002											
--Increase Due to New Thermal Oxidizer	109.7	151.4	8.8	30.7	30.7	9.1	0.89	7.7	--	--	--
--Increase Due to Modified No. 4 Comb. Boiler	548.7	37.8	--	--	--	--	0.47	21.9	--	--	--
--Increase Due to BSW System w/Condensate Treatment	--	--	--	--	--	48.6	58.7	--	--	--	--
--Decrease Due to Existing Thermal Oxidizer	-749.8	-49.5	-0.3	-20.6	-20.6	-3.2	-0.3	-26.9	--	--	--
--Decrease Due to Existing BSW System w/o Condensate Treatment	--	--	--	--	--	-52.1	-62.9	--	--	--	--
--Net Change	-91.4	139.7 [c]	8.5	10.1	10.1	2.4	-3.14	2.7	--	--	--
New Package Boiler (9/02) (Permit No. 1070005-018-AC) - startup Oct. 2002											
--Increase Due to New Package Boiler (EU 044)	0.1	39.4	16.5	1.5	1.5	1.1	--	--	c	c	c
--Decrease from old No. 6 Package Boiler	-0.07	-9.2	-2.1	-0.15	-0.15	--	--	--	c	c	c
--Net Change	0.03	30.20	14.40	1.35	1.35	1.1	--	--	c	c	c
Brown Stock Washer and Oxygen Delignification System (7/04) (Permit No. 1070005-024-AC) - startup Feb. 2006											
--Increase Due to No. 4 Comb. Boiler/No. 5 Power Boiler	236.3	--	0.3	--	--	4.0	17.1	9.5	--	--	--
--Increase Due to Pulp Storage Tanks	--	--	--	--	--	63.1	9.6	--	--	--	--
--Decrease from existing BSW System, BL Filter, etc.	--	--	--	--	--	-128.5	-77.1	--	--	--	--
--Net Change	236.3 [c]	--	0.3	--	--	-61.4	-50.4	9.5	--	--	--
No. 4 Power Boiler Shutdown (Sep. 2003)	-270.6	-33.6	-3.6	-18.1	-15.7	-0.2	--	-11.9	-0.005	-0.000081	-0.027
Total Contemporaneous Emission Changes	**-362.0**	**-3.4**	**19.6**	**-6.7**	**-4.3**	**-58.10**	**-53.5**	**0.3**	**-0.005**	**-0.000081**	**-0.027**
TOTAL NET CHANGE*	**-3,476.5**	**405.2**	**1,473.2**	**105.0**	**83.5**	**417.9**	**4.2**	**-128.8**	**0.11**	**0.0019**	**-0.380**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0.6	0.1	3.0
PSD REVIEW TRIGGERED?	No	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No

Notes:

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

[b] Based on actual emissions for 2004 and 2005 from Table 2-1 (without NCGs, SOG, DNCGs).

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

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

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

[f] Based on Table 2-3 unless otherwise noted.

[g] Based on calculations in Appendix D unless otherwise noted.

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APR 30 2007

BUREAU OF AIR REGULATION

STATE OF FLORIDA

County of Putnam

The undersigned personally appeared before me, a Notary Public for the State of Florida, and deposes that the Palatka Daily News is a daily newspaper of general circulation, printed in the English language and published in the City of Palatka in said County and State; and that the attached order, notice, publication and/or advertisement:

Florida Department of Enviro

Was published in said newspaper 1 time(s) with said publication being made on the following dates:

04/24/2007

The Palatka Daily News has been continuously published as a daily newspaper, and has been entered as second class matter at the post office at the City of Palatka, Putnam County, Florida, each for a period of more than one year next preceding the date of the first publication of the above described order, notice and/or advertisement.

M. McGill

Sworn to and subscribed to before me this 24th day of April, 2007 by Mary McGill, Administrative Assistant, of the Palatka Daily News, a Florida corporation, on behalf of the corporation.

Mary Kaye Wells

Mary Kaye Wells, Notary Public

My commission expires July 22, 2007

Notary Seal
Seal of Office:

MARY KAYE WELLS
MY COMMISSION # DD 196678
EXPIRES: July 22, 2007
Bonded Thru Notary Public Underwriters

_____ Personally known to me, or
_____ Produced identification:
__✓__ Did take an oath

PUBLIC NOTICE

Florida Department of Environmental Protection
Bureau of Air Regulation

Project No. 1070005-038-AC/Draft Air Permit No. PSD-FL-380

Georgia-Pacific Consumer Operations LLC - Palatka Mill

Putnam County, Florida

Applicant: The applicant for this project is the Georgia-Pacific Consumer Operations LLC. The applicant's authorized representative and mailing address is: Mr. Keith Wahoske, Vice President - Palatka Operations, Georgia-Pacific Consumer Operations LLC, P.O. Box 919, Palatka, Florida 32178-0919.

Facility Location: Georgia-Pacific Consumer Operations LLC operates an existing paper and pulp mill in Palatka, located North of CR 216 and West of US 17 in Putnam County, Florida.

Project: The applicant proposes to modify the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler. The project will result in the following potential emissions increases: 1473 tons/year of carbon monoxide (CO); 405 tons/year of nitrogen oxides (NOx); 105 tons/year of particulate matter (PM); 84 tons/year of particulate matter with an aerodynamic diameter of 10 microns or less (PM10); 4.2 tons/year of sulfuric acid mist; and 418 tons/year of volatile organic compounds (VOC). The project includes conversion of the No. 5 Power Boiler from a primary fuel of residual oil to natural gas. This will result in a reduction of more than 3400 tons per year of sulfur dioxide. Pursuant to Rule 62-212.400, F.A.C., the project is subject to preconstruction review for the prevention of significant deterioration (PSD) of air quality for emissions of CO, NOx, PM, PM10, and VOC. The draft permit establishes emissions standards for these pollutants based on the Best Available Control Technologies as determined by the Department.

An air quality impact analysis was conducted. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. The maximum predicted PSD Class II increments of NO2, SO2, and PM10 consumed by all sources in the area, including this project, will be as follows:

PSD Class II Increment

PM10

24-hour

Consumed (ug/m3)	22
Allowable (ug/m3)	30
Percent Consumed	73

Annual

Consumed (ug/m3)	0
Allowable (ug/m3)	17
Percent Consumed	0

SO2

3-hour

Consumed (ug/m3)	125
Allowable (ug/m3)	512
Percent Consumed	24

24-hour

Consumed (ug/m3)	60
Allowable (ug/m3)	91
Percent Consumed	66

Annual

Consumed (ug/m3)	8
Allowable (ug/m3)	20
Percent Consumed	40

NO2

Annual

Consumed (ug/m3)	3
Allowable (ug/m3)	25
Percent Consumed	12

NO2 and PM10 emissions from the project have no significant impact on the PSD Class I Okefenokee National Wilderness Area (NWA), the Chassahowitzka NWA and Wolf Island NWA The maximum predicted PSD Class I increments of SO2 consumed in these Class I areas by all sources, including this project, will be as follows:

PSD Class I Increment

SO2

3-hour

Consumed (ug/m3)	24.4
Allowable (ug/m3)	25
Percent Consumed	98

24-hour

Consumed (ug/m3)	4.14
Allowable (ug/m3)	5
Percent Consumed	83

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 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of this Public Notice or receipt of a written notice, 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 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 (in a proceeding initiated by another party) 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 when and how each petitioner received notice of the agency action or decision; (d) A statement of all disputed issues of material fact; (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 including an explanation of how the alleged facts relate to the specific rules or statutes; 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.

Legal No. 04530987
4/24/07

Annual	
Consumed (ug/m3)	0
Allowable (ug/m3)	2
Percent Consumed	0

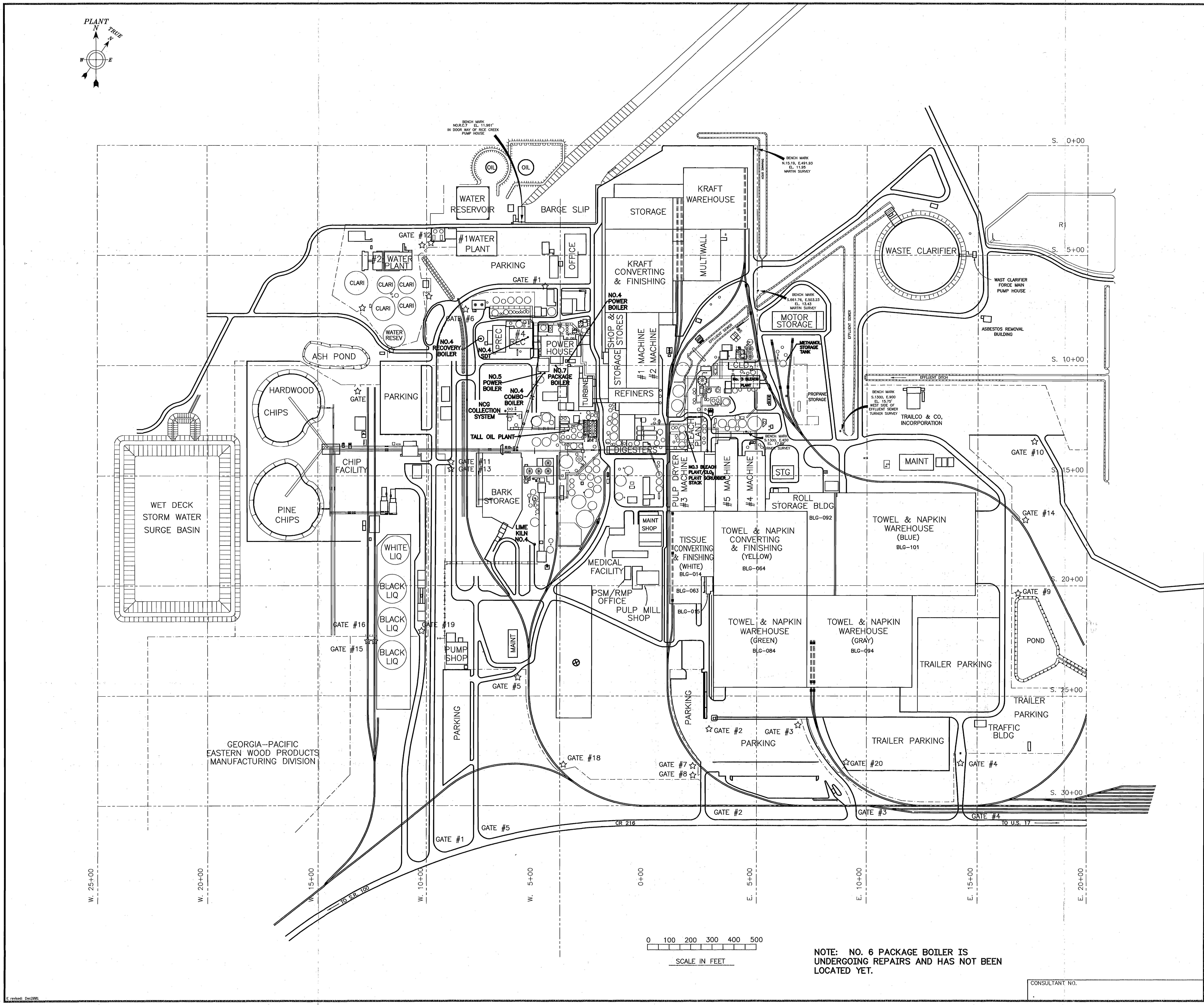
Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements 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.

Notice of Intent to Issue Air 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 the 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 Draft Permit for a period of 30 days from the date of publication of the Public Notice. Written comments must be postmarked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

1070005-038-AC (1)



NOTE: NO. 6 PACKAGE BOILER IS UNDERGOING REPAIRS AND HAS NOT BEEN LOCATED YET.

NOTES

LEGEND & INFORMATION

☆	GATE
═══	RAILROAD TRACK
— — —	FENCE

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

REV.	DATE	DESCRIPTION	DRN.	CHK'D	AP'D
2	6/28/05	UPDATED BORDER	JEM		
1	11/27/02	GOLDER TITLE V REVISION	FWH		DAB

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

HUDSON NO.

Georgia-Pacific

THE GROWTH COMPANY

PALATKA OPERATIONS

TITLE - V REVISION APPLICATION
0237624/4/4.4/4.4.1/GP-FI-C2

DRAWN	TRUJILLO 11/25/02	SCALE	1" = 150'
CHECKED		AFE NO.	
APPROVED		FILENAME	00010352.DWG
APPROVED		AREA	83

G-P DRAWING NO.
290-8464MI-000-0009-006

CONSULTANT NO.

CONSULTANT:

REV. 2