TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

APPLICANT

Georgia-Pacific Consumer Operations, LLC
215 County Road 216
Palatka, Florida 32177

Palatka Mill
Facility ID No. 1070005

PROJECT

Project No. 1070005-089-AC

Application for Air Construction Permit
Nos. 1 -4 Evaporator Set and No. 4 Concentrator Replacement, Routing of LVHC NCGs to No. 4 Recovery Boiler, Shutdown of Thermal Oxidizer (EU 07) and Condensate Stripper System (EU 047)

COUNTY

Putnam, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Northeast District Office
Permitting Program
8800 Baymeadows Way West, Suite 100
Jacksonville, Florida 32256

March 11, 2015

DRAFT

1. APPLICATION INFORMATION

1.1. Applicant Name and Address

Georgia-Pacific Consumer Operations, LLC
215 County Road 216
Palatka, Florida 32177

Authorized Representative: Mr. Kevin J. Curry, Vice President – Manufacturing

1.2. Processing Schedule

01/26/2015	Department received the Application for Air Permit – Long Form.
02/24/2015	Request for Additional Information
03/11/2015	Additional Information Received
03/13/2015	Draft Permit Issued

1.3. Glossary of Common Terms

Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of this permit.

1.4. Facility Description and Location

Georgia-Pacific Consumer Operations, LLC (Georgia-Pacific) operates the existing Palatka Mill, which is a Kraft pulp and paper mill that consists of major activities areas such as: chip handling, pulping, bleaching, chemical recovery, utilities, paper machines, converting, and turpentine and tall oil production. The existing Palatka Mill is located in Putnam County at 215 County Road 216 in Palatka, Florida.

The Palatka Mill is categorized under Standard Industrial Classification (SIC) Code Nos. 2611 and 2621. The Universal Transverse Mercator (UTM) coordinates of the facility are Zone 17, 434.00 kilometers (km) East and 3,283.4 km North. The location of Putnam County is shown in **Figure** 1 while a satellite view of the facility is shown in **Figure 2**. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to state and federal Ambient Air Quality Standards (AAQS).

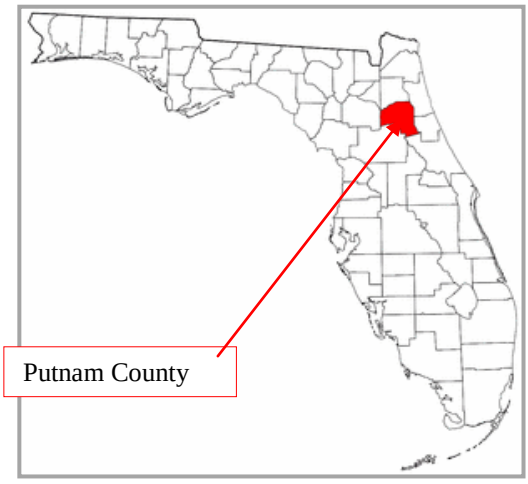


Figure 1: Location of Putnam County, Florida

Figure 2: Satellite view of Palatka Mill

1.5. Project and Process Description:

The Palatka Mill is proposing to replace the existing multiple effect evaporators and concentrator in order to increase the solids content of the black liquor solids (BLS) as-fired in the No. 4 Recovery Boiler. In addition, the Palatka Mill intends to make changes to the No. 4 Recovery Boiler to allow the unit to become the primary destruction device for the mill's low-volume, high concentration (LVHC) non-condensable gas (NCG) stream as well as the only destruction device for the off gases (in the form of liquid methanol) from a new condensate steam stripper system, methanol rectifier, and condenser.

The project will consist of the following changes to the facility:

- Shutdown of the existing Thermal Oxidizer (EU 037)
- Shutdown of the existing Condensate Stripper System (EU 046)
- Shutdown of the existing multiple effect evaporator system (Nos. 1 - 4 Evaporator sets and No. 4 concentrator);
- Modification of the No. 4 Recovery Boiler to introduce the LVHC NCG stream into the boiler for destruction via a dedicated burner. The No. 4 Recovery Boiler will function as the primary control device for the LVHC NCG stream and will fire rectified methanol blended with BLS as a supplemental fuel;
- Installation of a new multiple-effect evaporator system (7 total effects "falling film" and concentrator). The new evaporators will increase the solids content of the black liquor solids (BLS) from the current 66 percent by weight to approximately 75 percent by weight. Although the percent solids content will increase, the total weight of solids burned in the No. 4 recovery boiler will not increase with this project;
- Installation of a new integrated foul condensate steam stripper and methanol rectification system;
- Installation of a new storage tank for 75 percent BLS
- Installation of a new storage tank for liquid methanol (from the new condensate steam stripper system);
- Installation of a new soap skimmer;
- Installation of a new soap storage tank.

Currently the foul condensate generated by the batch digesters and the Nos. 1, 2, 3 4 evaporator sets, and No. 4 Concentrator is routed to the Condensate Stripper (EU 046) to remove methanol and other HAP's. The stripper off gases (SOGs) are vented to the No. 4 Combination boiler for destruction.

Under this project, the existing condensate stripper system and multiple effect evaporators and concentrator will be shutdown and replaced with a new multiple effect evaporator system (7 total effects including a concentrator) that includes a new integrated foul condensate steam stripper. The mill foul condensates will be routed to this new condensate steam stripper and the SOGs will be directed to a rectifying column where the methanol will be concentrated and condensed into 80/20 methanol and water mixture and blended with BLS prior to being burned as a supplemental fuel for the No. 4 Recovery Boiler. There will be no additional equipment required for the blending of the methanol and black liquor other than pump and piping. The existing black liquor burners will be used to burn the black liquor and methanol blend. During extended outage periods when BLS cannot be processed in the No. 4 Recovery Boiler, the methanol will be stored in a new 19,750 gallon storage tank. A new 158,540 gallon storage tank will also be installed for the 75 percent BLS.

Additionally, a new soap skimmer will be installed with an associated storage tank. The soap skimmer is a tank that has a rake and internal compartment. Black liquor (approximately 30 percent solids) from the fourth effect of the evaporator is pumped to the soap skimmer, where the rake is used to remove the soap. The soap is routed to the Tall Oil Plant (EU 031) for processing. The black liquor is then pumped back to the third effect of the evaporator system.

No changes will be made to the existing blow heat evaporation system which is comprised of the Accumulator and Pre-Evaporator.

The project will establish the No. 4 Recovery Boiler as the primary control device for the destruction of LVHC NCGs from the Digesters, the new MEE system, and the Turpentine Condensing system by introducing these gases into the boiler via a dedicated burner. When utilized in this mode, the existing spray tower pre-scrubber will be used to remove sulfur from the Batch NCG streams (Batch Digester System) and the separate spray tower pre-scrubber will be used to remove the sulfur from the Continuous NCG Streams (the new MEE System) prior to destruction in the boiler. NCGs from the Turpentine Condensing System will be vented directly to the boiler for destruction.

The No. 4 Recovery Boiler will be utilized as the only control device for the destruction of the Stripper Off Gases (as liquid methanol) from the new integrated condensate steam stripper system that is being installed as a part of this project. The liquid methanol will be blended with BLS prior to firing as a supplemental fuel in the boiler. The NCGs from the new multiple effect evaporator system along with those from the new liquid methanol storage tank will be collected in the existing NCG collection system for burning in the No. 4 Recovery Boiler.

The No. 4 Combination Boiler will remain as the secondary control device for the destruction of LVHC NCGs. When utilized in this mode, a spray tower pre-scrubber is used to remove sulfur from the Batch NCG streams (Batch Digester System) and a separate spray tower pre-scrubber will be used to remove the sulfur from the Continuous NCG Streams (the new MEE System) prior to destruction in the boiler. NCGs from the Turpentine Condensing System are vented directly to the boiler for destruction. The No. 4 Combination Boiler will no longer be utilized as the secondary control device for the destruction of stripper off-gases from the existing Condensate Steam Stripper (EU 046) or the new integrated condensate steam stripper system being installed as part of this project.

The No. 4 Combination Boiler will also remain the control device for the destruction of the high-volume, low-concentration (HVLC) dilute-noncondensable gases (DNCGs) from the brown stock washer system (Nos. 5, 6, and 7 BSW lines), the associated pressure knotters and screens, the oxygen delignification system, the post oxygen delignification washer, and the bleach plant pre-washer (decker).

After successful startup, shakedown, and compliance demonstration of the new equipment authorized by this project, the existing MEE System (Nos. 1-4 Evaporator Sets and No. 4 Concentrator), Thermal Oxidizer (Emissions Unit ID No. 037) and Condensate Stripper System (Emissions Unit ID No. 046) will be permanently shut down.

This project will add, remove, modify, or otherwise affect the following emissions units.

FACILITY REGULATORY CLASSIFICATION

Facility ID No. 1070005	
ID No.	**Emission Unit Description**
016	No. 4 Combination Boiler (modify)
018	No. 4 Recovery Boiler (modify)
037	Thermal Oxidizer (remove)
046	Condensate Stripper System (remove)
---	Existing Multiple Effect Evaporator System (Nos. 1-4 Evaporator Sets and No. 4 Concentrator) (remove)
052	Multiple Effect Evaporator System, 7 Total Effects and Integrated Condensate Steam Stripper System including methanol rectifier, condenser (add)

Operation of EUs 015, 017, 019, 031, 035, 036, 039, 044, 045, 047, 048, 050, and 051 at the facility are not affected by this permitting action.

1.6. Process Flow Diagram

Figure 3, provided by the applicant, is a process flow diagram of the proposed project.

1.7. Facility Regulatory Category Summary

- The facility **is** a major source of hazardous air pollutants (HAP).
- The facility **has no** units subject to the acid rain provisions of the Clean Air Act.
- The facility **is** a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility **is** a major stationary source in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.
- The facility **does** operate units subject to the New Source Performance Standards (NSPS) of 40 Code of Federal Regulations (CFR) 60.
- The facility **does** operate units subject to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) of 40 CFR 63.

2.0 PSD APPLICABILITY

2.0.1. General PSD Applicability

For areas currently in attainment with the state and federal AAQS or areas otherwise designated as unclassifiable, the Department regulates major stationary sources of air pollution in accordance with Florida's PSD preconstruction review program as defined in Rule 62-212.400, F.A.C. Under preconstruction review, the Department first must determine if a project is subject to the PSD requirements ("PSD applicability review") and, if so, must conduct a PSD preconstruction review. A PSD applicability review is required for projects at new and existing major stationary sources. In addition, proposed projects at existing minor sources are subject to a PSD applicability review to determine whether potential emissions *from the proposed project itself* will exceed the PSD major stationary source thresholds. A facility is considered a major stationary source with respect to PSD if it emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant; or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the following 28 PSD-major facility categories: fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), Kraft pulp mills, portland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion

plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants and charcoal production plants

Once it is determined that a project is subject to PSD preconstruction review, the project emissions are compared to the "significant emission rates" defined in Rule 62-210.200, F.A.C. for the following pollutants: carbon monoxide (CO); nitrogen oxides (NO_X); sulfur dioxide (SO_2); particulate matter (PM); particulate matter with a mean particle diameter of 10 microns or less (PM_{10}); volatile organic compounds (VOC); lead (Pb); fluorides (Fl); sulfuric acid mist (SAM); hydrogen sulfide (H_2S); total reduced sulfur (TRS), including H_2S; reduced sulfur compounds, including H_2S; municipal waste combustor organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans; municipal waste combustor metals measured as particulate matter; municipal waste combustor acid gases measured as SO_2 and hydrogen chloride (HCl); municipal solid waste landfills emissions measured as non-methane organic compounds (NMOC); and mercury (Hg). In addition, significant emissions rate also means any emissions rate or any net emissions increase associated with a major stationary source or major modification which would construct within 10 kilometers of a Class I area and have an impact on such area equal to or greater than 1 $\mu g/m^3$, 24-hour average.

If the potential emission exceeds the defined significant emissions rate of a PSD pollutant, the project is considered "significant" for the pollutant and the applicant must employ the Best Available Control Technology (BACT) to minimize the emissions and evaluate the air quality impacts. Although a facility or project may be *major* with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "significant" regulated pollutants.

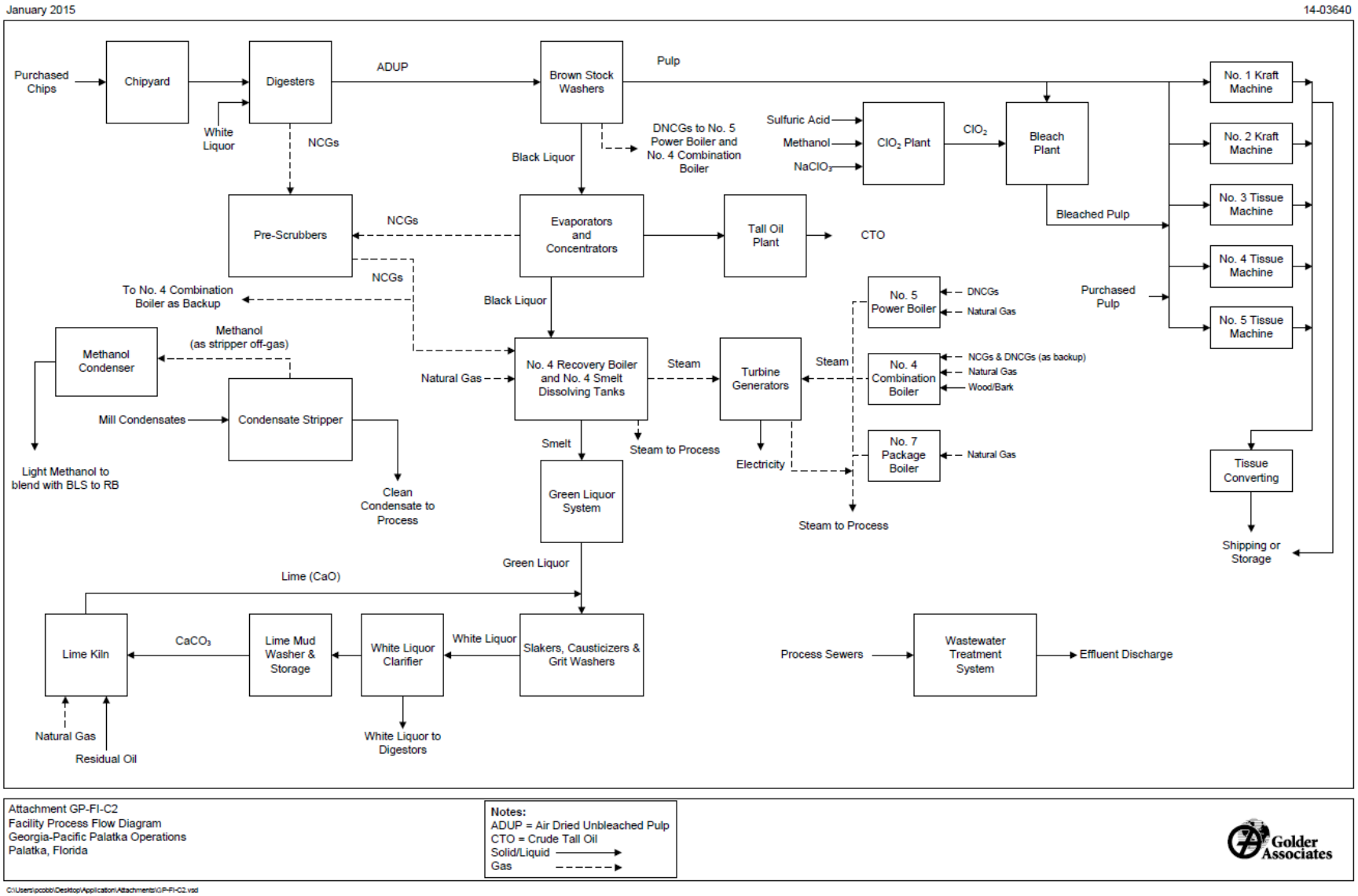
2.0.2. PSD Applicability for Project

The project is located in Putnam County which is in an area that is currently in attainment with the AAQS or is otherwise designated as unclassifiable.

The list given in the citation includes the category of "Kraft pulp mills". The given category applies to the facility before and after the proposed project. The Palatka Mill is a major stationary source based on actual emissions of and potential to emit 100 tons/year or more of several individual PSD pollutants.

The project is not subject to PSD review due to greenhouse gases. It is noted that on June 23, 2014, the Supreme Court issued a decision addressing the application of stationary source permitting requirements to greenhouse gases in *Utility Air Regulatory Group (UARG) v. Environmental Protection Agency (EPA)*, No. 12-1146. The Supreme Court said that EPA may not treat greenhouse gases as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V Permit.

The Supreme Court also said that PSD permits that are otherwise required (based on emissions of other pollutants) may continue to require limitations on greenhouse gases emissions based on the application of Best Available Control Technology (BACT). As shown in **Table 8** below, the proposed project does not trigger PSD review for any other pollutant. As such, the increases in GHG emissions do not trigger PSD review based on the Supreme Court decision.



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

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

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Figure 3

TABLE 1

Pollutant	Annual Emissions, Tons/Year				Further Analysis Required?
	Baseline Actual [a]	Projected Actual [b]	Increase [c]	Significant Emissions Rate	
SO_2	99.78	8.10	0	40	No
NO_X	472.18	539.79	67.61	40	Yes
CO	1249.93	791.54	0	100	No
PM	96.62	81.96	0	25	No
PM_{10}	79.71	77.65	0	15	No
$PM_{2.5}$	64.54	65.10	0.56	10	No
VOC	22.36	45.65	23.30	40	No
TRS	7.99	4.59	0	10	No
SAM	12.53	2.46	0	7	No
Lead	5.65×10^{-3}	4.31×10^{-3}	0	0.6	No
Mercury	1.42×10^{-3}	1.54×10^{-3}	1.13×10^{-4}	0.1	No
GHG	975,160	1,080,248	105,088	0	Yes
CO_2e	976,964	1,082,268	105,304	75,000	Yes

a. Baseline actual emissions were calculated based on the following highest consecutive 2-year average: 6/2008 – 5/2010 (SO_2,); 7/2005 – 6/2007 (NO_X, GHG, CO_2e); 10/2006 – 9/2008 (CO, Hg); 2/2005 – 1/2007 (PM, PM_{10}, $PM_{2.5}$, TRS); 12/2006 - 11/2008 (VOC); 4/2008 – 3/2010 (SAM); 2/2008 - 1/2010 (Pb).

b. Projected actual emissions included BLS storage tank and Soap Skimmer Tank. The projected actual black liquor solids (BLS) processing rate for this project was determined to be 816,500 tons BLS/year, methanol combustion (3,620 TPY), NGC combustion (facility-wide pulp production of 501,145 ADTUBP/yr), and natural gas firing of 10% of the total permitted annual heat input rate is 10,807,320 MMBtu/year. The projected heat input to the No. 4 Recovery Boiler is methanol & BLS combustion (9,656,913 MMBtu/yr), Natural gas combustion (1,178,220 MMBtu/yr); Natural gas alone during startup (83,000 MMBtu/yr), Natural gas co-fired with BLS (1,095,220 MMBtu/yr). Projected activity factors for new BLS and soap skimmer storage tanks (8,760 hours/yr operation).

c. The increase from the project is the difference between the projected and baseline actual emissions.

The applicant determined the project related emissions (which cannot be excluded from the project actual emissions as emissions that could have been accommodated), as well as the emissions that could be excluded because they are increases that are not related to the project.

The project related emissions:

TABLE 2

Pollutant	Project Related Emissions (TPY)
NO_x	2.12
GHG	10,865
CO_2e	11,010

The emission increases not related to the project (i.e. excludable) determined as the difference of the projected actual emissions minus the baseline emissions minus the project related emissions:

TABLE 3

Pollutant	**Emission Increases Not Related to the Project (TPY)**
NO_x	65.50
GHG	94,222
CO_2e	94,294

The applicant determined the NO_x and GHG emissions that the No. 4 Recovery Boiler could have accommodated during baseline period as allowed per Rule 62-210.200(244)(c), F.A.C. During the baseline periods (July 2005 – June 2007), the monthly emission rates were divided by the number of operating hours in that month and then multiplied by 8,760 hr/yr in order to project an annual emission rate. GP acknowledges that the No. 4 Recovery Boiler could not have operated for 8,760 hr/yr, even if the demand had existed. GP multiplied these annualized emission rates by the trailing 12-month percent uptime values (see Table 4-10 in the submitted application).

GP believes that the No. 4 Recovery Boiler could have accommodated the annualized emission rates described above during the 24-month baseline period had the same operating conditions experienced during the highest emitting month continued for a full year. The annualized "could have accommodated (CHA)" emission rates were used to determine the initial annual emissions that could have been accommodated during the baseline period (see Table 4-8 of the submitted application). As stated above, all CHA emissions are unrelated to the project and, therefore, are excluded from the projected actual emissions. The initial CHA emission rates are summarized below:

TABLE 4

Pollutant	**Initial Could Have Accommodated Emissions (TPY)**
NO_x	504.28
GHG	1,017,756
CO_2e	1,019,623

Emissions of NO_x are limited from the No. 4 Recovery Boiler (Permit No. 1070005-086-AV):

- NO_x: 80.0 ppmvd @ 8% O2 and 168.5 lb/hr (both limits are based on a 30-day rolling CEMS average). This emission limit corresponds to an annual permitted NOx emission rate of 738.03 TPY.

The calculated CHA emission rates for NO_x are below this corresponding annual emission limit. GHG are not currently limited.

GP determined the final CHA emissions by comparing the initial CHA emissions to the Projected Actual Emissions "PAE". The CHA emissions are a subset of PAE, so the final CHA emissions cannot be greater than the PAE. Therefore the final CHA emissions were determined by taking the smaller value between the initial CHA emissions and the PAE as shown below:

TABLE 5

Pollutant	Initial Could Have Accommodated Emissions (TPY)	PAE (TPY)	Final CHA Emissions (TPY)
NO_x	504.28	539.79	504.28
GHG	1,017,756	1,080,248	1,017,756
CO_2e	1,019,623	1,082,268	1,019,623

GP determined the emissions that could be excluded from the projected actual emissions due to demand growth. First, the potentially excludable emissions were determined by subtracting the BAE from the final CHA emissions. This calculation represents the full amount of emissions that could potentially be excluded from the PAE, if all of the emissions increases were not related to the project"

TABLE 6

Pollutant	Final CHA Emissions (TPY)	Baseline Actual Emissions (TPY)	Potentially Excludable Emissions (CHA minus BAE)
NO_x	504.28	472.18	32.10
	1,017,756	975,160	42,596
CO_2e	1,019,623	976,964	42,660

GP determined that since a portion of the emissions increases are related to the proposed project, the demand growth emissions (DGE) that may be excluded from the PAE were calculated by selecting the smaller amount between the emissions increases not related to the project and the potentially excludable emissions:

TABLE 7

Pollutant	Potentially Excludable Emissions (TPY)	Emission Increases Not Related to the Project (TPY)	Demand Growth Emissions (TPY)
NO_x	32.10	65.50	32.10
GHG	42,596	94,222	42,596
CO_2e	42,660	94,294	42,660

GP determined the increase as a result of the project by subtracting the BAE from the PAE, and then subtracting the DGE emissions. This increase was then compared to the PSD significant emission rates in order to determine if the project will result in a PSD significant increase in any pollutant.

TABLE 8

Pollutant	Annual Emissions, Tons/Year					PSD Review Triggered?
	Baseline Actual (TPY)	Projected Actual (TPY)	Demand Growth Emissions (TPY)	Emissions Increases Due to Project (TPY)	PSD Significant Emissions Rate (TPY)	
SO_2	99.78	8.10	---	0	40	No
NO_X	472.18	539.79	32.10	35.51	40	No
CO	1249.93	791.54	---	0	100	No
PM	96.62	81.96	---	0	25	No
PM_{10}	79.71	77.65	---	0	15	No
$PM_{2.5}$	64.54	65.10	---	0.56	10	No
VOC	22.36	45.65	---	23.30	40	No
TRS	7.99	4.59	---	0	10	No
SAM	12.53	2.46	---	0	7	No
Lead	5.65×10^{-3}	4.31×10^{-3}	---	0	0.6	No
Mercury	1.42×10^{-3}	1.54×10^{-3}	---	1.13×10^{-4}	0.1	No
GHG	975,160	1,080,248	42,596	62,492[a]	0	No
CO_2e	976,964	1,082,268	42,660	62,645[a]	75,000	

[a] GHG emission increase must be greater than or equal to zero TPY (mass) **and** CO_2e emissions increase must be greater than or equal to 75,000 TPY.

As shown in the above table, total project emissions will not exceed the PSD significant emissions rates; therefore, the project is not subject to PSD preconstruction review.

3.0. FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION (FDEP) REVIEW

PSD Applicability

The applicants PSD analysis compared baseline actual emissions with projected actual emissions. Baseline actual emissions for each pollutant were based on the highest 24- month annual average of the last 10 years (February 2005 – September 2014). Actual emissions were determined based on operating data, available stack test data, CEMS data, and published emissions factors. The 2007 boiler rebuild, authorized under Permit No. 1070005-038-AC/PSD-FL-380, was accounted for in in the actual emissions data. Table 4-4 in the application, showed the maximum annual BLS burned in the No. 4 Recovery Boiler during this time period was 831,687 tons of BLS/year. Fuel oil usage data showed the maximum annual heat input to the recovery boiler was 527,510 MMBtu/year. Natural gas usage data showed the maximum annual heat input to the recovery boiler was 301,294 MMBtu/year.

The projected emissions were estimated using same emission factors used to calculate the baseline actual emissions, emission factors developed by Georgia Pacific based on historical operating data, the company's own representation, and the company expected business activity. The applicant determined that the No. 4 Recovery Boiler will burn a maximum of 816,500 tons of BLS/year over the next 5 years. The activity factor used for the combustion of natural gas was based on a maximum annual natural gas heat input of 1,178,220 MMBtu/year, which is equivalent to 10% of the annual heat input to the boiler. Methanol combustion was determined to be a

maximum of 3,620 tons/yr and NCG combustion was based on the facility wide pulp production of 501,145 ADTUBP/yr. Two additional sources were accounted for in determining the projected actual emissions: the new BLS storage tank for 75-percent BLS, and the new Soap Skimmer Tank. Emissions were based on a projected activity factor of 8,760 hours of operation/yr. The recovery boiler will remain subject to all existing emissions standards.

The reductions in emissions due to the permanent shutdown of the thermal oxidizer (EU 037) were not considered in the PSD applicability analysis.

The Department has determined that based on the increase in NO_X emissions of 35.51 tons/year, and the increase in VOC emissions of 23.30 tons/year, the applicant shall compute and report annual emissions for a period of 5 years following resumption of regular operations of the No. 4 Recovery Boiler after this project for these pollutants. The permittee shall use data collected from the CEMS to determine and report the actual annual emissions of NO_X from the No. 4 Recovery Boiler to demonstrate that the SER for NO_X emissions has not been exceeded due to this project. VOC emissions stack test results shall be used to determine and report the actual emissions of VOC from the No. 4 Recovery Boiler to demonstrate that the SER for VOC emissions has not been exceeded due to this project.

3.0.1. Federal Regulation (NSPS and NESHAP)

The U. S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 specifies New Source Performance Standards (NSPS) for numerous industrial categories. Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP) based on specific pollutants. Part 63 specifies NESHAP based on the Maximum Achievable Control Technology (MACT) for numerous industrial categories. The Department adopts these federal regulations on a quarterly basis in Rule 62-204.800, F.A.C.

3.0.1.1. NSPS Applicability

An existing source can become subject to NSPS if the existing facility is "*modified"* or "*reconstructed".*

Modification is defined as *any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification. …..use the following to determine emission rate: Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP-42.... where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase*.

Reconstruction is defined as *the replacement of components of an existing facility to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and it is technologically and economically feasible to meet the applicable standards set forth in this part.*

40 CFR 60 Subpart Db.

No. 4 Recovery Boiler:

Modification: NSPS Subpart Db regulates emission of NO_X, SO_2 and PM. The addition of a NCG dedicated burner represent a physical change in the No. 4 Recovery Boiler. However, the applicant mentions that 40 CFR 60.40b(f) provides an exemption for a modification determination. This section states, "any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined

under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart. As such the project does not constitute "modification".

The liquid methanol will be injected into the black liquor pipe immediately prior to the refractometers and ringheader system. GP states that there is no additional equipment required for the blending of the liquid methanol and the black liquor other than pumps and piping. The existing black liquor burners will be used to burn the black liquor and methanol blend. The facility states that the primary function of firing SOGs (as liquid methanol) in the No. 4 Recovery Boiler is to reduce HAP emissions from the pulping process, and as such does not constitute a modification as defined by 40 CFR 60.14(e).

Reconstruction: The facility states that the addition of the NCG burner is not a replacement of components, so "reconstruction" does not apply. The facility also states that the costs of the burner are minimal compared to the cost of constructing a new recovery boiler. As such the project does not constitute "reconstruction". With regards to the blending of the SOGs (as liquid methanol) with black liquor in the No. 4 Recovery Boiler, the facility states that the project will not constitute "reconstruction" because the existing black liquor burners will be used to burn the black liquor and methanol blend.

Therefore, based on the above analysis, the No. 4 Recovery Boiler is not subject to 40 CFR 60 Subpart Db as a result of this proposed project.

40 CFR 60 Subpart BB- Standards of Performance for Kraft Pulp Mills and

40 CFR 60 Subpart BBa - Standards of Performance for Kraft Pulp Mill Affected Sources for Which Construction, Reconstruction, or Modification Commenced After May 23, 2013

No. 4 Recovery Boiler.

The No. 4 Recovery Boiler is not currently subject to NSPS Subpart BB or BBa for Kraft Pulp mills. Subparts BB and BBa regulate emissions of PM and TRS.

Modification: 40 CFR 60.14(e) provides a list of activities that are not considered modifications by themselves. 40 CFR 60.14(e)(5) exempts the addition or use of any device or system whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system determined to be less environmentally beneficial. The applicant states that the primary function of the burner is for NCG destruction to reduce HAP emissions from the pulping process. The applicant also believes that it is not expected that NCG burning will cause an increase in emissions of PM or TRS from the No. 4 Recovery Boiler on an hourly basis. Therefore the change would not be considered to be a modification under NSPS. With regards to the blending of liquid methanol with black liquor, the facility states that the primary function of firing SOGs (as liquid methanol) in the No. 4 Recovery Boiler is to reduce HAP emissions from the pulping process, and as such does not constitute a modification as defined by 40 CFR 60.14(e).

Reconstruction: As previously stated, the project does not constitute "reconstruction".

Multiple Effect Evaporator (MEE) System and Integrated Condensate Steam Stripper System.

The proposed MEE system and the Condensate Steam Stripper System at the Palatka Mill are defined as an "affected facility" under the NSPS Subpart BB and BBa rules. Because these facilities will be constructed after May 23, 2013, they will be subject to NSPS Subpart BBa.

§60.283a A TRS emissions standard of 5 parts per million by dry volume corrected to 10 percent oxygen (ppmvd @ 10% O2) applies, unless the following conditions are met:

- The NCGs are collected in an LVHC closed-vent system meeting the requirements of 40 CFR 63.450 and

- The NCGs are combusted in a recovery furnace not subject to the provisions of Subpart BB or BBa
- The NCGs are subjected to a minimum temperature of 1,200°F for at least 0.5 seconds

The NCG stream from the new MEE system (including the integrated stripper system and methanol storage tank) will be collected in the existing LVHC closed-vent system and combusted in the No. 4 Recovery Boiler (and No. 4 Combination Boiler as backup). The NCGs will be introduced into the flame zone of the boilers via a dedicated burner, and are expected to meet the minimum combustion requirements.

It is noted while the digester system and brownstock washing system are also defined as "affected facilities" under these rules, they are not being modified or reconstructed as part of the proposed project, and therefore are not considered in this applicability determination.

NSPS Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

Soap Skimmer Storage Tank, 75-percent BLS Storage Tank, Liquid Methanol Storage Tank, Soap Storage Tank.

This subpart is applicable to storage vessels with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

§60.110b exempts the following storage vessels from Subpart Kb:

- Storage vessels with a capacity less than 75 cubic meters (m^3; 19,813 gallons)
- Storage vessels with a capacity less than 151 m^3 (39,890 gallons) and greater than or equal to 75 m^3 (19,813 gallons) with a maximum true vapor pressure less than 15.0 kilopascal (kPa)
- Storage vessels with a capacity greater than 151 m^3 (39,890 gallons) with a maximum true vapor pressure less than 3.5 kPa

The three proposed storage tanks will have the following storage capacities:

- Soap Skimmer – 633,350 gallons
- 75% BLS Tank – 158,540 gallons
- Methanol Tank – 19,750 gallons
- Soap Tank – 16,800 gallons

The applicant states that the maximum true vapor pressure of weak black liquor (soap skimmer) is 0.97 kPa , while the maximum true vapor pressure of strong black liquor (75% BLS tank) is approximately 0.973 kPa, Both of these vapor pressures are less than 3.5 kPa.

The capacity of both the methanol and soap tanks are less than 19,813 gallons.

Therefore none of the proposed new storage tanks will be subject to Subpart Kb.

3.0.1.2. NESHAP Applicability

40 CFR 63 Subpart S—National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry

The evaporator system, which is part of the pulping system, is currently considered part of an existing affected

source under National Emission Standards for Hazardous Air Pollutants (NESHAPS) Subpart S

(40 CFR 63, Subpart S) for the pulp and paper industry. Under Subpart S, the affected source is "the total of all HAP emission points in the pulping and bleaching systems."

The Subpart S "new source" provisions apply when an existing affected source is constructed or reconstructed, or when a new pulping or bleaching line is added. An existing affected source is "reconstructed" as defined under 40 CFR 63.2, if the fixed capital cost of replacement components exceeds 50 percent of the fixed capital cost that it would take to construct a comparable new source, and it is technologically and economically feasible for that reconstructed source to meet the new source standards. The pulping system, pulping process condensates, and evaporator system are defined under 40 CFR 63.441 as:

Pulping system means all process equipment, beginning with the digester system, and up to and including the last piece of pulp conditioning equipment prior to the bleaching system, including treatment with ozone, oxygen, or peroxide before the first application of a chemical bleaching agent intended to brighten pulp. The pulping system includes pulping process condensates and can include multiple pulping lines.

Pulping process condensates means any HAP-containing liquid that results from contact of water with organic compounds in the pulping process. Examples of process condensates include digester system condensates, turpentine recovery system condensates, evaporator system condensates, LVHC system condensates, HVLC system condensates, and any other condensates from equipment serving the same function as those previously listed. Liquid streams that are intended for byproduct recovery are not considered process condensate streams.

Evaporator system means all equipment associated with increasing the solids content and/or concentrating spent cooking liquor from the pulp washing system including preevaporators, multi-effect evaporators, concentrators, and vacuum systems, as well as associated condensers, hotwells, and condensate streams, and any other equipment serving the same function as those previously listed.

The applicant states that the proposed project does not include the construction of any new pulping or bleaching lines. The project does include replacement of the existing evaporators and concentrators with a new evaporator and condenser system, which will be part of the pulping system. The applicant estimates the cost of replacement to be approximately 32 percent of the cost of a new pulping system (approximately $238 million). Therefore, the project does not constitute "reconstruction". As a result, the pulping system will not be "reconstructed" under the NESHAP definition and the unit will continue to be an existing source under 40 CFR 63, Subpart S.

40 CFR 63 Subpart MM—National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills

The No. 4 Recovery Boiler is currently considered part of an existing affected source under 40 CFR 63, Subpart MM for chemical recovery combustion sources at kraft, soda, sulfite, and stand-alone semichemical pulp mills. Subpart MM regulates emissions of organic and metal HAPs.

An existing source can be considered a new source under the NESHAP if it is determined to have gone through "reconstruction" as defined under 40 CFR 63.2, which applies a 50% cost threshold for new components as compared to the fixed capital cost of a comparable new source.

Under NESHAP MM, the affected source is "each existing chemical recovery system" as defined under 40 CFR 63.861 as "all existing DCE and NDCE recovery furnaces, smelt dissolving tanks, and lime kilns at a Kraft or soda pulp mill." The applicant states that the proposed project does not replace any components of the existing No. 4 Recovery Boiler or the chemical recovery system. Therefore, the project does not constitute "reconstruction".

As a result, the No. 4 Recovery Boiler will continue to be an existing source under 40 CFR 63, Subpart MM..

3.0.2. State Rule Applicability

Projects at stationary sources with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of Environmental Protection (Department) to establish regulations regarding air quality as part of the Florida Administrative Code (F.A.C.), which includes the following applicable chapters: 62-4 (Permits); 62-204 (Air Pollution Control – General Provisions); 62-210 (Stationary Sources – General Requirements); 62-212 (Stationary Sources – Preconstruction Review); 62-213 (Operation Permits for Major Sources of Air Pollution); 62-296 (Stationary Sources - Emission Standards); and 62-297 (Stationary Sources – Emissions Monitoring). Specifically, air construction permits are required pursuant to Rules 62-4, 62-210 and 62-212, F.A.C.

3.0.2.1. Rule 62-210.300, F.A.C., Permits Required

Unless exempted, the owner or operator of any facility or emissions unit which emits or can reasonably be expected to emit any air pollutant shall obtain appropriate authorization from the Department prior to undertaking any activity at the facility or emissions unit for which such authorization is required.

3.0.2.2. Rule 62-212.300, F.A.C. - General Preconstruction Review Requirements

This rule generally applies to the construction or modification of air pollutant emitting facilities in those parts of the state in which the state ambient air quality standards are being met.

The reporting and monitoring of actual emissions of VOC and NO_X for 5 years following the project will ensure the PSD BACT determinations will be met.

3.0.2.3. Rule 62-296.404, F.A.C., Tall Oil Plants and Kraft (Sulfate) Pulp Mills

This rule regulates TRS emissions from digester systems, multiple effect evaporator systems, and condensate stripper systems. Rule 62-296.404(3)(a)1., F.A.C., requires that gaseous emissions be collected and incinerated in one of the following:

- Lime kiln or calciner meeting the requirements of 62-296.404(3)(e), F.A.C. or the applicable NSPS
- Kraft recovery furnace meeting the requirements of 62-296.404(3)(c), F.A.C. or the applicable NSPS
- Combustion device meeting the requirements of 62-296.404(3)(f), F.A.C. or the applicable NSPS
- Subject to 5 ppmvd as a 12-hour average if a means other than incineration in a combustion device pursuant to subparagraph 62-296.404(3)(a)1., F.A.C., is used.

The facility is proposing to use the No. 4 Recovery Boiler as the control device for the LVHC NCGs, and continue using the No. 4 Combination Boiler as the backup. The No. 4 Recovery Boiler is already subject to the requirements of Rule 62-296.404(3)(c), F.A.C. The No. 4 Combination Boiler is already subject to the requirements of Rule 62-296.404(3)(f), F.A.C.

3.0.2.4 Chapter 62-297, F.A.C.

This rule establishes general compliance test requirements as well as standards for persons engaged in visible emissions observations.

4.0 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. Rita Felton-Smith is the project engineer responsible for reviewing the application and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Permitting Authority's Northeast District Office, Permitting Program, 8800 Baymeadows Way West, Suite 100, Jacksonville, Florida 32256.