Prevention of Significant Air Quality Deterioration Review
Of Weyerhaeuser – Flint River Operations
Located in Macon County, Georgia

PRELIMINARY DETERMINATION
SIP Permit Application No. 15956
July 2005

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program **(SSPP)**
Prepared by
Heather Cottrell – Chemicals Unit
Modeling Approved by: **Peter Courtney** **Dale Kemmerick** **Data and Modeling Unit**
Reviewed and Approved by:
David Matos – Chemicals Unit Coordinator **Heather Abrams – SSPP Manager**
Ron Methier – Chief, Air Protection Branch

SUMMARY

The Environmental Protection Division (EPD) has reviewed the Weyerhaeuser - Flint River Operations application for a permit for modifications to the existing pulp mill such that the mill achieves a 10 percent production increase. The proposed project will occur in two phases. The first phase involves modifications to the chip bin to increase chip feed uniformity to the digester, modifications to the digester wash circulation piping, installation of a digester extraction liquor heat exchanger, and upgrades to the recovery boiler. The second phase will involve replacement of the current cylinder mould decker drum filter and associated filtrate tank and vacuum pump with a wash press and filtrate tank, upgrades to the B-concentrator to allow for increased pressures, upgrades to the dryer winder system, modifications to the recovery boiler solids firing rate, and improvements to the finished pulp roll handling system.

The main source of emissions associated with this project is the increased throughput for Recovery Boiler U500. Following the modifications, black liquor throughput will increase from a maximum of 100 tons per hour to 110 tons per hour. The unit will continue to be capable of firing fuel oil. Periods of fuel oil use will include startups, shutdowns, periods when no black liquor is available for combustion, and when black liquor availability is low due to process upsets. The boiler is equipped with an ESP for controlling particulate matter and Weyerhaeuser will continue to operate continuous emissions monitoring systems (CEMS) and a continuous opacity monitoring system (COMS) on the unit. The CEMS will monitor SO_2, NO_X, TRS, and O_2. These monitors are already in place and operating in order to comply with current air quality regulations or for emissions tracking purposes.

Emissions associated with the digester system, evaporator system, and high-volume low-concentration (HVLC) system (new wash press and filtrate tank) are currently required to be incinerated. Weyerhaeuser will continue to conduct this practice for the modified units.

Weyerhaeuser has accepted a short-term SO_2 emission limit for the operation of the existing lime kiln in order to demonstrate compliance with the PSD Increment analysis. The facility currently operates a CEMs for SO_2 and O_2 on this unit, which is not being modified in this permitting action. The facility will continue to use the monitors to demonstrate compliance with this limit.

Weyerhaeuser’s proposed modifications will be located in Macon County, which is classified as “attainment” or “unclassifiable” for SO_2, PM_{10}, NO_X, CO, and ozone (VOC) in accordance with Section 107 of the Clean Air Act, as amended August 1977.

The EPD review of the data submitted by Weyerhaeuser related to the proposed modifications indicates that the project will be in compliance with all applicable state and federal air quality regulations.

It is the preliminary determination of the EPD that the proposal provides for the application of Best Available Control Technology (BACT) for the control of PM_{10}, VOC, CO, SO_2, NO_X, and TRS, as required by federal Prevention of Significant Deterioration (PSD) regulation 40 CFR 52.21(j).

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment in the area surrounding the facility (no Class I area is located within 200 km of the facility). It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Weyerhaeuser - Flint River Operations for the modifications necessary to increase production by 10 percent. Various conditions have been incorporated into the current Title V operating permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A.

1.0 INTRODUCTION

On January 14, 2005, Weyerhaeuser - Flint River Operations (Weyerhaeuser) submitted an application for an air quality permit to conduct modification at the existing pulp mill such that production capabilities are increased by 10 percent. The modifications will take place at Old Stagecoach Road in Oglethorpe (Macon County), Georgia.

Based on the proposed project, the estimated incremental increases of regulated pollutants from the facility are listed in Table 1.

Table 1: Emissions Increases from the Production Increase Project

Pollutant	Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM/PM_{10}	126.1	25/15	Yes
VOC	187.7	40	Yes
NO_X	466.7	40	Yes
CO	1414	100	Yes
SO_2	1288	40	Yes
TRS	24.59	10	Yes
Pb	0.013	0.6	No
Fluorides	N/a	3	No
H_2SO_4	2.45	7	No

The net increases were calculated by subtracting the past actual emissions (based upon the annual average emissions from January 2003 through December 2004) from the future potential emissions of the recovery boiler and associated emission increases from non-modified equipment. Table 2 details this emissions summary. The emissions calculations for Tables 1 and 2 can be found in detail in the facility's PSD submittal (see Appendix D of Application No. 15956) and the additional information package submitted on March 20, 2005. These calculations have been reviewed and approved by the Division. The emissions from the chip bin and dryer winder system are accounted for through the Facility Emission Cap in Condition 2.2.1.b of the current permit. Please see the narrative of the initial Title V permit for a discussion of the cap system.

Table 2: Net Change in Emissions Due to the Major PSD Modification

Pollutant	Recovery Boiler Increase (tpy)		Associated Units Increase (tpy)	Total Increase (tpy)
	Past Actual	Future Potential		
PM/PM_{10}	223.9	273.5	76.47	Yes
VOC	10.65	120.7	77.66	Yes
NO_X	517.4	867.4	116.8	Yes
CO	297.2	1584	127.2	Yes
SO_2	46.63	1298	35.61	Yes
TRS	11.71	32.06	4.24	Yes
Pb	4.68E-3	5.78E-3	0.0118	No
Fluorides	N/a	N/a	N/a	No
H_2SO_4	7.80	9.64	0.61	No

Based on the information in Tables 1 and 2, Weyerhaeuser's proposed modification, as specified per Georgia Air Quality Application No. 15956, is classified as a major modification under PSD because the potential emissions of PM/PM_{10} exceed 25/15 tpy, VOC, NO_X, and SO_2 exceed 40 tpy each, CO exceed 100 tpy, and TRS exceed 10 tpy.

Through its new source review procedure, EPD has evaluated Weyerhaeuser's proposal for compliance with State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination.

2.0 PROCESS DESCRIPTION

On January 14, 2005, Weyerhaeuser submitted an application for an air quality permit to conduct modifications at the existing pulp mill such that production capabilities are increased by 10 percent. The modifications will take place at Old Stagecoach Road, in Oglethorpe (Macon County), Georgia. The proposed project will occur in two phases. The first phase involves modifications to the chip bin to increase chip feed uniformity to the digester, modifications to the digester wash circulation piping, installation of a digester extraction liquor heat exchanger, and upgrades to the recovery boiler. The second phase will involve replacement of the current cylinder mould decker drum filter and associated filtrate tank and vacuum pump with a wash press and filtrate tank, upgrades to the B-concentrator to allow for increased pressures, upgrades to the dryer winder system, modifications to the recovery boiler solids firing rate, and improvements to the finished pulp roll handling system.

The main source of emissions associated with this project is the increased throughput for Recovery Boiler U500. Following the modifications, black liquor throughput will increase from a maximum of 100 tons per hour to 110 tons per hour. The boiler is equipped with an ESP for controlling particulate matter. Weyerhaeuser will continue to operate continuous emissions monitoring systems (CEMS) and a continuous opacity monitoring system (COMS) as part of the project as required by 40 CFR 63 Subpart MM and 40 CFR 60 Subpart BB and to ensure compliance with the BACT and PSD Avoidance limits. The CEMS will monitor SO_2, NO_X, CO, TRS, and O_2. Weyerhaeuser has accepted a short-term SO_2 emission limit for the operation of the existing lime kiln in order to demonstrate compliance with the PSD Increment analysis. The facility currently operates a CEMs for SO_2 and O_2 on this unit, which is not being modified in this permitting action. The facility will continue to use the monitors to demonstrate compliance with this limit.

The Weyerhaeuser permit application and supporting documentation are included in Appendix A and can be found online at www.georgiaair.org/airpermit.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

State Rules

Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1) requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Georgia Rule 391-3-1-.03(8)(b) continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

Georgia Rule (b) [391-3-1-.02(2)(b)] is a general rule limiting the opacity of emissions from a source to less than 40 percent. This regulation applies to the recovery boiler, power boiler, lime kiln, smelt tank, slaker, lime bins, and woodyard activities. The limit is subsumed for the recovery boiler by opacity limits and/or reporting requirements under 40 CFR 63 Subpart BB, 40 CFR 63 Subpart MM, and 40 CFR 60 Subpart Db.

Georgia Rule (d) [391-3-1-.02(2)(d)] limits opacity and particulate matter emissions from all fuel-burning equipment. It also limits NO_X emission from equipment with a maximum heat input capacity or greater than 250 MMBtu/hr. The power boiler is the only unit at the mill that is subject to this rule. The mill complies with limits of 0.10 lb/MMBtu of particulate matter, 20 percent opacity, and 0.3 lb/MMBtu of nitrogen oxides when burning fuel oil.

Georgia Rule (e) [391-3-1-.02(2)(e)], commonly known as the process weight rule, limits PM emissions based on either of the following equations where E = emission rate (lb/hr) and P = process input rate (ton/hr). Georgia Rule (e) applies to the recovery boiler, lime kiln, smelt tank, slaker, lime bins, and woodyard activities. The rule is not subsumed by any other regulation for the recovery boiler because the allowable emissions are dependent on the process input.

$$\text{For } P= 30 \text{ ton/hr}, \quad E = 4.1 \times P^{0.67}$$
$$\text{For } P> 30 \text{ ton/hr}, \quad E = 55 \times P^{0.11} - 40$$

Georgia Rule (g) [391-3-1-.02(2)(g)] applies to all fuel-burning sources. Paragraph 1 limits the emission of sulfur dioxide on a lb/MMBtu basis for sources capable of firing fossil fuel(s) at a rate exceeding 250 MMBtu/hr and constructed or modified after January 1, 1972. This paragraph of the rule applies only to the power boiler, which is limited to 0.8 pounds of sulfur dioxide per MMBtu. Paragraph 2 of the rule limits the percentage of sulfur, by weight, in the fossil fuel burned in sources below 100 MMBtu/hr of heat input to no more than 2.5 percent and in sources equal to or greater than 100 MMBtu/hr of heat input to no more than 3 percent. This paragraph applies to the recovery boiler, lime kiln, and power boiler. Paragraph 3 allows the facility to use fuel with higher sulfur content only if the facility utilizes add-on controls on the lime kiln to reduce sulfur dioxide emissions to at or below the levels that would be emitted if compliant fuel was utilized. Paragraph 3 does not apply at the Weyerhaeuser facility. Georgia Rule (g) limits the sulfur content of the fuel burned in the recovery boiler to no more than 3 percent by weight.

Georgia Rule (n) [391-3-1-.02(2)(n)] is a general rule that applies to fugitive dust. The rule requires the facility to take all reasonable precautions to minimize fugitive dust and keep opacity from fugitive dust to less than 20 percent. The units being modified or installed for this project are not subject to this rule.

Federal Rule - PSD

The regulations for PSD in 40 CFR 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply to any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or to all other sources having potential emissions of 250 tons per year or more of any regulated pollutant. They also apply to any modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements:

- Application of BACT for each regulated pollutant that would be emitted in significant amounts
- Analysis of the ambient air impact
- Analysis of the impact on soils, vegetation, and visibility
- Analysis of the impact on Class I areas
- Public notification of the proposed plant in a newspaper of general circulation

Definition of BACT

The PSD regulation requires that BACT be applied to all regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case, EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS). In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose and enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

The BACT determination should, at a minimum, meet two core requirements.[1] The first core requirement is that the determination follow a "top-down" approach. The second core requirement is that the selection of a particular control system as BACT must be justified in terms of the statutory criteria and supported by the record and must explain the basis for the rejection of other more stringent candidate control systems.

EPD's procedures for performing a top down BACT analysis are set forth in EPA's Draft New Source Review Workshop Manual (Manual), dated October 1990. One critical step in the BACT analysis is to determine if a control option is technically feasible.[2] If a control is determined to be infeasible, it is eliminated from further consideration. The Manual applies several criteria for determining technical feasibility. The first is straightforward: if the control has been installed and operated by the type of source under review, it is demonstrated and technically feasible.

For controls not demonstrated using this straightforward approach, the Manual applies a more complex approach that involves two concepts for determining technical feasibility: availability and applicability. A technology is considered available if it can be obtained through commercial channels. An available control is applicable if it can be reasonably installed and operated on the source type under construction. A technology that is available and applicable is technically feasible.

The Manual provides some guidance for determining availability. For example, a control is generally considered available if it has reached the licensing and permitting stages of development. However, the Manual further provides that a source would not be required to experience extended time delays or resource penalties to allow research to be conducted on new technologies. In addition, the applicant is not expected to experience extended trials learning how to apply a technology on a dissimilar source type. Consequently, technologies in the pilot scale testing stages of development are not considered available for BACT.

As mentioned before, the Manual also requires available technologies to be applicable to the source type under construction before a control is considered technically feasible. For example, deployment of the control technology on the existing source with similar gas stream characteristics is generally a sufficient basis for concluding technical feasibility. However, even in this instance, the Manual would allow for an applicant to make a demonstration on the contrary. For example, an applicant could show that unresolved technical difficulties with applying a control to the source under consideration (e.g., size of the unit, location of the proposed site, and operating problems related to the specific circumstances of the source) make a control technically infeasible.

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[1] The discussion of the core requirements is taken from the Preamble to the Proposed NSR Reform, 61 FR 38272.

[2] Discussion on technical feasibility is taken from the PSD Final Determination for AES Londonberry, L.L.C., Rockingham County, New Hampshire, authored by the U.S. EPA Region I, Air Permits Program.

According to the Environmental Appeals Board (see In re: Kawaihae Cogeneration Project, 7 E.A.D. 107 at page 1996, EAB 1997), the section on "collateral environmental impacts" of a proposed technology has been interpreted to mean that "if application of a control system results directly in the release (or removal) of pollutants that are not currently regulated under the Act, the net environmental impact of such emissions is eligible for consideration in making the BACT determination." The Appeals Board continues, "The Administration has explained that the primary purpose of the collateral impacts clause is… to temper the stringency of the technological requirements whenever one or more of the specified collateral impacts – energy, environmental, or economic – renders the use of the most effective technology inappropriate." Lastly, the Appeals Board states, "Unless it is demonstrated to the satisfaction of the permit issuer that such unusual circumstances exist, then the permit applicant must use the most effective technology."

The five steps of a top-down BACT review procedure identified by EPA per BACT guidelines are listed below:

Step 1:	Identify all control technologies
Step 2:	Eliminate technically infeasible options
Step 3:	Rank remaining control technologies by control effectiveness
Step 4:	Evaluate most effective controls and document results
Step 5:	Select BACT

The following is a discussion of the applicable rules and regulations. The top-down BACT analysis begins on page 9 of this preliminary determination.

Federal Rule – 40 CFR 60 Subpart A

40 CFR 60 Subpart A, *General Provisions*, imposes generally applicable provisions for initial notifications, initial compliance testing, monitoring, and recordkeeping requirements. The facility must comply with the general provisions because equipment at the facility is subject to 40 CFR 60 Subpart D, 40 CFR 60 Subpart BB, 40 CFR 60 Subpart Kb, and 40 CFR 60 Subpart Db. The recovery boiler, evaporator system, and digester system are subject to 40 CFR 60 Subpart BB.

Federal Rule – 40 CFR 60 Subpart D

40 CFR 60 Subpart D, *Standards of Performance for Fossil Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971*, applies to the power boiler. The subpart imposes limits for particulate matter (0.10 lb/MMBtu), opacity (20 percent except for one 6-minute period of not more than 27 percent), sulfur dioxide (0.80 lb/MMBtu), and nitrogen oxides (0.30 lb/MMBtu). The subpart does not apply to the recovery boiler because the unit fires fuel oil only during startup, shutdown, and process upsets.

Federal Rule – 40 CFR 60 Subpart Db

40 CFR 60 Subpart Db, *Standards of Performance for Industrial-Commerical-Institutional Steam Generating Units*, now applies to the recovery boiler because the facility is making a modification that will increase the potential emission rates of pollutants from the boiler. The facility will limit the annual fuel capacity for oil to less than 10 percent; therefore the facility will not be subject to a NO_X limit under this subpart. The unit will be subject to an opacity limit of 20 percent. The facility will also be subject to a limit of 0.5 lb/MMBtu for sulfur dioxide based on a 30 percent annual capacity factor for fossil fuel combustion. The facility is not subject to a particulate matter limit under this subpart.

Federal Rule – 40 CFR 60 Subpart Kb

40 CFR 60 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*, applies to storage tanks based on the tank dimensions and the material being stored.

Federal Rule – 40 CFR 60 Subpart BB

The Weyerhaeuser mill was constructed after 1976; therefore it is subject to 40 CFR 60 Subpart BB, *Standards of Performance for Kraft Pulp Mills*. 40 CFR 60 Subpart BB provides performance standards for emission units at Kraft pulp mills, including the digester system, brownstock washer system, multiple-effect evaporator system, recovery boiler, smelt tank, lime kiln, and condensate stripper system. The subpart limits particulate matter to 0.044 gr/dscf at 10 percent O_2 for the recovery furnace, 0.20 pounds per ton of black liquor solids for the smelt tank, and 0.066 gr/dscf or 0.13 gr/dscf at 10 percent O_2 from the lime kiln depending on whether natural gas or fuel oil is burned.

40 CFR 60 Subpart BB also establishes TRS standards for all subject emission units. The digester system, brownstock washer system, evaporator system, and condensate stripper system are limited to 5 ppm TRS on a dry basis at 10 percent O_2 when not combusted in a subject lime kiln, recovery boiler, or other incinerator (including the power boiler). Not that when TRS is combusted in the power boiler, the gases must be combusted at a minimum temperature of 1,200 degrees Fahrenheit for at least 0.5 seconds. The recovery boiler is subject to a TRS limit of 5 ppm on a dry basis at 8 percent O_2. TRS emissions from the smelt tank are limited to 0.033 pound per ton black liquor solids. TRS emissions from the lime kiln are limited to 8 ppm on a dry basis at 10 percent O_2.

Federal Rule – 40 CFR 63 Subpart A

40 CFR 63 Subpart A, *General Provisions*, imposes generally applicable provision for initial notifications, initial compliance testing, monitoring, and recordkeeping requirements. The facility must comply with the general provisions because equipment at the facility is subject to 40 CFR 63 Subpart S, 40 CFR 63 Subpart MM, 40 CFR 63 Subpart EEEE, and 40 CFR 63 Subpart DDDDD. Equipment subject to these rules includes the recovery boiler, evaporator system, digester system, wash press, and filtrate tank.

Federal Rule – 40 CFR 63 Subpart S

40 CFR 63 Subpart 63 S, *National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry*, requires that various pulping and bleaching process air emissions and process condensate emissions at pulp mills that are major HAP sources be collected and treated. Total HAP emissions from the various components of the pulping system, including the following, must be controlled: each LVHC system (digesters, turpentine recovery, evaporator, and steam stripper systems), knotter and screen systems (if emissions are above 0.1 and 0.2 lb/ton oven dried pulp, respectively), select portions of the up washing system, and the decker system. Note that Weyerhaeuser is not required to control HAP emissions from the brownstock diffusion washer vent, the first stage of the brownstock diffusion washer filtrate tank vent, and the oxygen delignification system provided that the facility controls HAP emissions from the weak liquor storage tank, boilout tank, utility tank, black liquor storage tanks, precipitator makedown tanks 1 through 3, salt cake mix tank, and operates the isothermal cooking system within the digester parameters specified in the permit. These variations from the standard 40 CFR 63 Subpart S requirements are a result of the Project XL Agreement established between Weyerhaeuser, the Georgia EPD, and the U.S. EPA. Under the Project XL Agreement the mill was also not required to control HAP emissions from the cylinder mound decker and its associated filtrate tank and vacuum pump; however, these units are being removed as part of the proposed project and the replacement wash press and filtrate tank will be controlled.

The collected process air HAP emissions are required to be enclosed and routed to a control device to achieve destruction. Weyerhaeuser currently routes the captured LVHC gases to the recovery boiler, power boiler, or lime kiln for destruction. The pulping process condensates are collected and discharged below the surface of the biological treatment system established for treatment of waste water to reduce total HAP to the required level of at least 10.2 lb/ton of oven dried pulp.

40 CFR 63 Subpart S also regulates the emission from the bleaching systems at pulp mills. The equipment where chlorinated compounds are added must be enclosed and emission from the equipment must be collected and routed to a control device. Weyerhaeuser routes most of the bleaching emissions to the bleach plant packed tower scrubber, which achieves the required maximum outlet concentration of 10 ppm or less of total chlorinated HAP; some of the emission with concentrations of less than 10 ppm of total chlorinated HAP are vented directly to the atmosphere. The facility does not use hypochlorite or chlorine in the bleaching system to reduce chloroform emissions.

Federal Rule – 40 CFR 63 Subpart MM

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*, requires the reduction of HAP emissions from the combustion sources at pulp mills that are major HAP sources. Specifically, the subpart requires HAP reduction from new or existing recovery boilers, smelt tanks, and lime kilns. Using particulate matter as a surrogate for metal HAP, the limits for the recovery boiler, smelt tank, and lime kiln are 0.044 gr/dscf at 8 percent O_2, 0.2 lb/ton black liquor solids fired, and 0.010 gr/dscf at 10 percent O_2, respectively. The proposed project will not alter the existing source states of the recovery boiler, as the threshold for reconstruction, 50 percent of the capital cost to install a new recovery boiler, will not be exceeded.

Federal Rule – 40 CFR 63 Subpart EEEE

40 CFR 63 Subpart EEEE, *National Emission Standards for Hazardous Air Pollutants for Organic Liquid Distribution*, regulates HAP emissions from organic liquid distribution tanks, loading racks, equipment leak components, and transport vehicles. The bleaching system methanol tank is subject to this regulation.

Federal Rule – 40 CFR 63 Subpart DDDDD

40 CFR 63 Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters*, was promulgated on September 13, 2004. 40 CFR 63 Subpart DDDDD regulates HAP emission from solid, liquid, and gaseous fuel fired boilers and indirect process heaters that are located at the facility that are major sources of HAP. The power boiler appears to be the only unit at the site that will be subject to this subpart. The recovery boiler is not subject to this regulation because it is regulated under 40 CFR 63 Subpart MM.

Federal Rule – 40 CFR 64

Under 40 CFR 64, the Compliance Assurance Monitoring Regulations (CAM), facilities are required to prepare and submit monitoring plans for certain emission units with the Title V application. The CAM Plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation applies to units that use a control device to achieve compliance with an emission limit and whose pre-controlled emissions levels exceed the major source thresholds under the Title V permitting program. Although other units may potentially be subject to CAM upon renewal of the Title V operating permit, such units are not being modified under the proposed project and need not be considered for CAM applicability at this time. Therefore, this applicability evaluation only addresses the recovery boiler, which employs an ESP for particulate matter control.

Pre-controlled particulate matter emissions from the recovery boiler exceed the Title V major source threshold of 100 tpy and are subject to an emission standard of 0.044 gr/dscf at 8 percent O_2 under 40 CFR 60 Subpart BB and 40 CFR 63 Subpart MM. The facility must also use the ESP to achieve the proposed BACT limit of 0.021 gr/dscf at 8 percent O_2. Thus, the recovery boiler meets the definition of a subject unit. However, the regulation provides an exemption. If the emission unit is subject to emission limits or standards under a Part 60 or Part 63 regulation proposed after November 15, 1990, the unit is exempt from CAM for those emissions. As 40 CFR 63 Subpart MM was promulgated after November 15, 1990, the recovery boiler is exempt from CAM for the limit. However, the facility is also complying with particulate matter limits under 40 CFR 60 Subpart BB, BACT, and Georgia Rule (e), which are not exempt from CAM.

Based on this analysis the Weyerhaeuser has submitted a CAM Plan that describes the general and performance criteria for two performance indicators, ESP total power and COMs data. Both indicators must be monitored on a continuous basis because post-control potential emissions from the boiler exceed 100 tpy. The CAM Plan appears in Part 5.2 of the permit amendment.

4.0 CONTROL TECHNOLOGY REVIEW

Recovery Boiler - Background

Kraft pulp mills operate recovery boilers by spraying spent chemical concentrated liquor from the digester, called black liquor, into the unit where the combustion process reduces the sodium sulfate in the black liquor to sodium sulfide (an active cooking chemical). Sodium hydroxide, another active cooking chemical, is consumed and converted to sodium carbonate during the pulping process and passes through the recovery boiler unchanged. The molten chemicals, called smelt, collect in the furnace bottom at about 3:1 ratio of sodium carbonate to sodium sulfide. The smelt is continuously withdrawn from the boiler into the smelt dissolving tank. The flue gas is exhausted from the boiler into an ESP for control of particulate matter. Weyerhaeuser has stated that the soda fume in the recovery boiler is more than 98 percent efficient for in situ process scrubbing of SO_2 in the flue gas under normal operating conditions.

As with all boilers, recovery boilers have special safety systems to prevent fuel/air explosions and steam explosions if steam pressure ratings are exceeded. However, chemical recovery boilers can experience other, unique types of explosions such as pyrolysis gas (CO, methane, hydrogen, and others) explosions and smelt/water explosions. If a recovery boiler experiences a “black out” where the flame extinguishes and the hot char bed continues to produce pyrolysis gases, then a spark or flame can reignite the gases and produced a fuel/air explosion. If a boiler tube develops a leak and water comes into contact with the molten salt at the bottom of the boiler, a very forceful explosion may take place. While such hazards are contained within a plant site and do not threaten the surrounding community, they pose a significant danger to employees and equipment. These special safety issues and the critical chemical reactions discussed previously are what makes a chemical recovery boiler unique and explains why some emission control technologies that may work for ordinary boilers are technically infeasible and even dangerous for a chemical recovery boiler.

Recovery Boiler – PM_{10}

The majority of PM_{10} emissions from the recovery boiler are sodium salts with about 80 percent of the PM_{10} being sodium sulfate and small amounts of potassium sulfate, sodium carbonate, and sodium chloride. These salts are primarily caused by the carryover of solids and sublimation and condensation of inorganic chemicals. The PM emissions of these salts are small in size with 50-100 percent of the particulate emissions being $PM_{2.5}$.

Some PM_{10} emissions can be attributed to the combustion of fossil fuels. Filterable PM_{10} emissions from fuel oil combustion depend not only on the completeness of combustion but also on the sulfur content of the oil. The lower the sulfur content, the lower the viscosity (due to desulfurization processes), resulting in better atomization and more complete combustion. ESPs are generally utilized to minimize PM_{10} emissions from recovery boilers.

Step 1: Identify all control technologies

Weyerhaeuser identified potentially applicable PM/PM_{10} control technologies based on a review of information published in technical journals and trade literature, information provided by prospective control technology vendors, and experience in conduction control technology review for similar types of equipment. Taking into account the physical and operational characteristics of the recovery boiler, the candidate control options are listed below.

Option 1: Proper Operating Practices
Option 2: Fabric Filters (Baghouse)
Option 3: Cyclone Separators
Option 4: Wet Scrubbers
Option 5: Electrostatic Precipitators

Proper Operating Practices
A properly operated recovery boiler will minimize the formation of PM/PM_{10} emissions. Proper design of the boiler concerns features such as the fuel and combustion air delivery system and the shape and size of the combustion chamber. Good operating practices typically consist of controlling parameters such as fuel feed rates and air/fuel ratios.

Fabric Filter (Baghouse)
A baghouse consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Dirty gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter and allows it to fall into a bin at the bottom of the baghouse.

Cyclone Separator
Cyclone separators remove solids from an air stream by application of centrifugal force. Typically, the particle-laden gas enters the top of the cyclone tangentially to the barrel and spins inside the device. Because of the shape of the device, the gas turns and forms a vortex in the center of the device as it moves upward to the exit duct. The particles are removed by centrifugal force, which drives them to the wall of the collector where they fall to the bottom due to gravity. Cyclones are efficient in removing larger, denser particles but are not as effective for fine particle removal (less than 5 µm in diameter).

Wet Scrubber
Wet scrubbers intercept dust particles using droplets of liquid (usually water). The larger, particle-enclosing water droplets are separated from the remaining droplets by gravity. The solid particles are then separated from the water.

Electrostatic Precipitator
An ESP removes particles from an air stream by electrically charging the particles, then passing them through a force field that causes them to migrate to an oppositely charged collector plate. The dust from the collector plates falls into a collection hopper at the bottom of the ESP. The collection efficiency of an ESP depends on the particle diameter, electrical field strength, gas flow rate, and plate dimensions. ESPs can be designed for both dry as well as wet applications. Weyerhaeuser presently operates an ESP to reduce PM emissions from the recovery boiler.

Step 2: Eliminate technically infeasible options

Option 2: Fabric Filters (Baghouse)

Baghouses encounter serious operational difficulties when utilized to control emissions from fuels with high moisture contents, especially black liquor solids, which result in emissions of hydroscopic particulate salts. Condensation of moisture on the fabric of baghouses will cause clogging of the fabric. Consequently, upset conditions would likely occur as the collected PM could not be removed by reverse air, shaker, or pulse-jets, causing the pressure across the baghouse to increase to an extremely high level. Review of the RBLC database indicates that no baghouse has been deemed BACT for chemical recovery boilers. As such, a baghouse is considered technically infeasible for the recovery boiler.

Option 3: Cyclone Separators

Cyclone separators are effective for removing particulate matter with diameters greater than 5 micrometers in size. As previously noted, most of the PM emissions from a recovery boiler have diameters less than 2.5 µm in size. Because this technology does not have the ability to capture and remove the type of PM associated with recovery boilers, the technology is considered to be technically infeasible. The RBLC search supports the exclusion of this technology.

Step 3: Rank remaining control technologies by control effectiveness

Table 3: Ranking of Control Technology

Control Technology Ranking	Control Technology	Control Efficiency	Additional Control Above Existing Emission Limit**
1	Electrostatic Precipitators	RLBC: 99.0-99.81% AP-42*: 98.9-99.1%	52% (ESP achieving 0.021 gr/dscf at 8 % O_2)
2	Wet Scrubbers	RLBC: No Data AP-42*: 73.3%	25%
3	Proper Operating Practices	N/a	N/a

*The efficiency values are taken from AP 42, Fifth Edition, Volume I Chapter 10: Wood Products Industry, Section 10.2: Chemical Wood Pulping.

**The control efficiencies represent an incremental level of control above a base case that is generally achievable when the technologies are applied to large industrial boilers. The scrubber is not anticipated to be able to remove any quantifiable amount of the PM/PM_{10} not currently removed by the existing ESP. For the purposes of this analysis only, the facility assumed a control efficiency of 25%.

Step 4: Evaluate most effective controls and document

Table 3 above shows that ESPs are the most effective devices for the control of particulate matter from recovery boilers. There are no environmental or economical impacts that would preclude Weyerhaeuser from operating an ESP.

Step 5: Select BACT

Weyerhaeuser is proposing to utilize the existing recovery boiler ESP to meet the proposed BACT limit. In addition, Weyerhaeuser conducted a review of BACT limits for particulate matter emitted from recovery boilers. The facility has proposed to meet a BACT limit of 0.021 gr/dscf at 8 percent O_2. As shown in Table 6-3 of the application, the proposed limit is equivalent to or lower than almost every PM limit approved during 2000 through 2002. These values range between 0.021 gr/dscf and 0.044 gr/dscf, with the exception of the International Paper Mill located in Mansfield, Louisiana, which lists a limit of 0.009 gr/dscf. However, when the supporting data listed in the RBLC is converted to a lb PM per ton BLS basis, the proposed Weyerhaeuser limit is lower. Finally, the EPD located only two limits in the database prior to 2000 that are lower. These include US Alliance in Alabama (0.015 gr/dscf) in 1998 and Apple Grove in West Virginia (0.012 gr/dscf) in 1996. Both of these limits were for brand new plants, not modifications to an existing boiler. The Apple Grove facility was never built.

Conclusion – PM_{10} Control

The Division has determined that Weyerhaeuser's proposal to use the existing ESP to control PM_{10} emissions constitutes BACT. The BACT emission limit has been established as 0.021 gr/dscf at 8 percent O_2. The facility will be required to conduct performance testing and establish an ESP total power level that demonstrates compliance with the limit. The facility will also continue to monitor the ESP total power level and report excursions to the Division.

Summary – PM_{10} Control Technology Review for Recovery Boiler U500

To fulfill the PSD permitting requirements for PM_{10}, a BACT analysis was conducted for the modified recovery boiler. The BACT selection for the boiler is summarized in Table 4.

Table 4: BACT Summary for the Proposed Modified Recovery Boiler U500

Pollutant	Control Technology	Proposed BACT Limit
PM_{10}	ESP	0.021 gr/dscf at 8% O_2

Recovery Boiler – VOC and CO

VOC and CO emissions result primarily due to incomplete combustion. Conditions leading to incomplete combustion include the following: insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction. Maintaining high combustion temperatures, lengthening residence time, and properly mixing fuel and combustion air can minimize VOC and CO emissions. It should be noted that combustion modifications taken to reduce NO_X emissions can result in increased VOC and CO emissions. VOC and CO emissions are discussed together because they can be controlled in many cases with the same control device.

Step 1: Identify all control technologies

Weyerhaeuser identified potentially applicable VOC and CO control technologies based on a review of information published in technical journals and trade literature, information provided by prospective control technology vendors, and experience in conducting control technology review for similar types of equipment. Taking into account the physical and operational characteristics of the recovery boiler, the candidate control options are listed below.

Option 1: Proper Operating Practices (VOC, CO)
Option 2: Thermal Oxidation (VOC, CO)
Option 3: Catalytic Oxidation (VOC, CO)
Option 4: Carbon Adsorption (VOC)
Option 5: Polymer Adsorption (VOC)
Option 6: Wet Scrubbing (VOC)
Option 7: Biofiltration (VOC, CO)

Proper Operating Practices

A properly operated recovery boiler will minimize the formation of VOC and CO emissions. Proper design of the boiler concerns features such as the fuel and combustion air delivery system and the shape and size of the combustion chamber. The Weyerhaeuser recovery boiler already employs what is considered to be proper design and operation.

Thermal Oxidation

In thermal oxidizers, VOC and CO are oxidized to CO_2 and water vapor at a high temperature with a residence time between one-half second and one second. Thermal oxidizers can be designed as conventional thermal units, recuperative units, or regenerative thermal oxidizers (RTOs). A conventional thermal oxidizer does not have heat recovery capability. Therefore, the fuel cost for a conventional thermal oxidizer is extremely high and is not suitable for high volume flow applications. In a recuperative unit, the contaminated inlet air is preheated by the combustion exhaust gas stream through a heat exchanger. It is common now to design an RTO with a thermal recovery efficiency 95 percent. RTOs are commonly used to control VOC and CO emissions in high-volume gas streams.

An RTO generally consists of at least two chambers packed with ceramic media. The VOC and CO laden gas enters one hot ceramic bed where the gas is heated to the desired combustion temperature. Auxiliary fuel may be required in this stage, depending on the heating value of the inlet gas. After reacting in the combustion zone, the gas then passes through the other ceramic bed, where the heat released from combustion is recovered and stored in the bed. The process flow is then switched so that the polluted gas is preheated by the ceramic bed. The system is operated in an alternating cycle, recovering up to 95 percent of the thermal energy during normal operation.

Catalytic Oxidation

Similar to an RTO, a regenerative catalytic oxidizer (RCO) oxidizes VOC and CO to CO_2 and water. However, an RCO uses catalysts to lower the activation energy required for the oxidation so that the oxidation can be accomplished at a lower temperature than in an RTO. As a result, the necessity for auxiliary fuel is lower than for an RTO. This technology is acceptable only for exhaust streams with a low particulate content.

Carbon Adsorption

Carbon adsorption can potentially be used to remove VOC from exhaust gas streams. The core component of a carbon adsorption system is an activated carbon bed contained in a steel vessel. The VOC gas passes through the carbon bed where the VOC is adsorbed on the activated carbon. The cleaned gas is discharged to the atmosphere. The spent carbon is regenerated either at an on-site regeneration facility or by an off-site activated carbon supplier. Spend carbon is regenerated by using steam to displace adsorbed organic compounds at high temperatures.

Polymer Adsorption

Polymer adsorption systems can potentially be used to remove VOC from exhaust gas streams. The core component of a polymer adsorption system is synthetic polymer designed to adsorb the target VOC. The polymer can be contained in fixed beds, fluidized beds, or fluidized beds in series with counter-current flow to VOC laden gas. The VOC laden gas passes through the polymer bed where the VOC is adsorbed on the polymer. The clean gas is discharged to the atmosphere. The spent polymer is regenerated by applying heat to displace the adsorbed organic compounds at high temperatures. The VOC is either recovered or burned in a separate device.

Wet Scrubbing

Scrubbing of gas or vapor pollutants from a gas stream is usually accomplished in a packed column (or other type of column) where pollutants are absorbed by countercurrent flow of a scrubbing liquid. Wet scrubbing is only effective for water soluble VOC.

Biofiltration

Biofiltration is a relatively recent air pollution control technology in which off-gases containing biodegradable organic compounds are vented, under controlled temperature and humidity through a special filter material containing microorganisms. As the exhaust gases pass through the biofilter, VOC and CO is absorbed on the filter material, and the microorganisms break down the compounds and transform them into CO_2 and H_2O with varying efficiency.

Step 2: Eliminate technically infeasible options

Option 2: Thermal Oxidation

Thermal oxidizers (including RTOs) have been widely used as VOC control technology in applications such as surface coating. However, using a RTO or similar oxidation technology to control CO or VOC from a combustion source is rare and may present new operational and maintenance problems.

A thermal oxidizer downstream of a boiler is equivalent to adding another combustion chamber where more oxygen is supplied to complete the oxidation of CO and VOC. The flue gas is reheated to a temperature at which the CO and VOC oxidation can take place. This poses an environmental problem, since additional fuel is required to reach this higher temperature. The combustion of this additional fuel in the thermal oxidizer is expected to raise levels of combustion-generated pollutants such as PM, NO_X, and SO_2.

Further, the sodium sulfate particulate and other sulfur compounds present in the exhaust stream of the recovery boiler is expected to damage the packing in an RTO. Applications of RTO in the pulp industry have a very short packing life because the sodium ash from wood derived fuel combustion reacts and degrades the packing. The use of an RTO is technically infeasible for the recovery boiler since this boiler's primary fuel is black liquor solids, which contains wood lignin. In addition, EPA's thermal incinerator fact sheet states that an incinerator is not recommended for controlling sulfur containing gases because of the formation of highly corrosive acid gases. The fact sheet also states that incinerators are not appropriate for low-concentration, high flow organic vapor streams. Low to moderate VOC streams are defined as 1,000 ppm to 1,500 ppm. The Weyerhaeuser boiler will be able to limit VOC emission to 40 ppm or less using good operating practices. Review of the RBLC reveals there are no entries for thermal oxidizers for CO or VOC control of recovery boilers. Thermal oxidation is infeasible for the recovery boiler and is not considered further in this analysis.

Option 3: Catalytic Oxidation

Catalytic oxidation is technically infeasible for implementation on the recovery boiler due to the sodium sulfate present in the exhaust stream. As with packing for a thermal oxidizer, sodium sulfate particles will collect on the catalysts and render them ineffective. If a catalytic oxidizer is installed downstream of the particulate control device, significant auxiliary fuel input will be required to raise the temperature of the flue gas. If a catalytic oxidizer is installed before the particulate control device in order to receive the hotter inlet gas, the heavy ash loading in the flue gas will blind the catalyst. Further, the flue gas will contain SO_2 from the oxidation of TRS in the dilute NCG stream; the SO_2 in the flue gas will poison the catalyst used to assist oxidation of CO and VOC to CO_2 in the catalytic oxidizer. Review of the RBLC reveals there are no recent entries for catalytic oxidizers for CO or VOC control on recovery boilers. The Apple Grove mill in West Virginia has an RBLC entry for the use of a catalytic oxidizer on its recovery boiler; however this facility was never built.

Option 4: Carbon Adsorption

Carbon adsorption is not recommended for exhaust streams with high humidity and temperatures above 150 °F. At approximately 400 °F, the temperature of the recovery boiler exhaust stream is significantly greater than 150 °F. Further, combustion of the black liquor solids results in high moisture levels in the exhaust stream. For these reasons, carbon adsorption is not a feasible control technology for recovery boiler VOC emissions.

Option 5: Polymer Adsorption

Polymer adsorption requires that the surface of the polymer remain clean. Recovery boiler emissions contain PM and condensable organic compounds that would coat the surface of the polymer beads, blocking access of the VOC to the pores where adsorption takes place, rendering them ineffective. Because of the loss of effectiveness over time, polymer adsorption is not a feasible control technology for recovery boiler VOC emissions. The EPA fact sheet for polymer adsorption does not list combustion sources as candidates for control by this method. In addition, the fact sheet indicates that the technology is most suitable for gas streams with VOC concentrations of 400 to 2,000 ppm. The Weyerhaeuser recovery boiler will be able to comply with a limit of 40 ppm using good operating practices. Polymer adsorption does not appear in the RBLC database for the control of VOC emissions from recovery boilers.

Option 6: Wet Scrubbing

Wet scrubbing for VOC removal is not technically feasible for application with recovery boilers combusting black liquor solids since the VOC emissions from the boiler are not all water soluble and therefore would not be removed from the gas stream. Wet scrubbing is therefore not a feasible control technology for the recovery boiler VOC emissions. In addition, the EPA fact sheet for scrubbers indicates that the technology is most appropriate for gas streams with concentrations of 250 to 10,000 ppm. The Weyerhaeuser recovery boiler will be able to comply with a limit of 40 ppm using good operating practices. Wet scrubbing does not appear in the RBLC database for the control of VOC emissions from recovery boilers.

Option 7: Biofiltration

A limiting parameter of biofiltration is its operating temperature. The maximum operating temperature of biofilters is approximately 100 °F. At higher temperatures, the microorganisms that comprise the biofilter cease adsorbing and metabolizing the VOC and CO. Cooling the emissions to biofilter operating temperatures is difficult to achieve, requiring either massive heat exchangers or large amounts of dilution air. It is not feasible to lower the recovery boiler exhaust stream to less than 100 °F, and therefore, biofiltration is not a feasible control technology for VOC and CO emissions from the recovery boiler.

Step 3: Rank remaining control technologies by control effectiveness

Table 5: Ranking of Control Technology

Control Technology Ranking	Control Technology	Control Efficiency
1	Proper Operating Practices	N/a

Step 4: Evaluate most effective controls and document

Proper operating practices are the only control technology that is feasible for the recovery boiler for the control of VOC and CO emissions.

Step 5: Select BACT

Weyerhaeuser is proposing to use proper operating practices on the existing recovery boiler to meet the proposed BACT limits. In addition, Weyerhaeuser conducted a review of BACT limits for VOC and CO emitted from recovery boilers. The facility has proposed to meet a BACT limit of 40 ppm on a dry basis at 8 percent O_2 (as carbon) for VOC and a limit of 300 ppm on a dry basis at 8 percent O_2 for CO.

The VOC limit proposed by Weyerhaeuser, which is equivalent to 0.24 pound per ton BLS, is lower than all RBLC limits approved in 2000 through 2002 for those plants where limits could be calculated on the same unit basis. These limits ranged between 0.28 pounds and 2.79 pounds per ton BLS. The Division also reviewed limits issued prior to 2000 and found only three limits lower than that proposed by Weyerhaeuser. Chesapeake in Virginia was issued a limit of 0.053 pound per ton BLS in 1991; however, this limit was for the construction of a brand new facility, not for the modification of an existing boiler. The others limits are 0.044 pound per ton BLS and 2.8 ppm, issued in 1989 to Boise Cascade mills in Maine and Minnesota, respectively. The latter mill is only 12 miles away from a Class I area, therefore it is reasonable to expect the limits to be low. The entries following 1989 are much higher than the Boise Cascade limits and are equal to or higher than the limit Weyerhaeuser has proposed.

The CO limit proposed by Weyerhaeuser, which is equivalent to 3.29 pounds per ton BLS, is lower than all but one RBLC limit approved in 2000 through 2002 for those plants where limits could be calculated on the same unit basis. The lowest limit in this time span is 2.44 pounds per ton BLS as issued to Weyerhaeuser, Marlboro, South Carolina in 2002. However, this list also includes a limit as high as 13.12 pounds per ton BLS issued in 2001 and the average limit for these years is over 6.5 pounds per ton BLS. In addition, the Division reviewed limits issued prior to 2000 and found them to be extremely variable. In practice, CO can be the most difficult pollutant to control and this appears to be reflected in the RBLC data.

As previously stated, there is a relationship between NO_X, CO, and VOC emissions because all three pollutants are dependant on fuel/air ratios and combustion temperature. Further operational measures that could reduce VOC/CO emissions (higher temperatures and more excess air) would have a detrimental effect on NO_X emissions. The proposed limits are low considering the NO_X/VOC/CO relationship and are low compared to the recent RBLC database entries.

Conclusion – VOC and CO Control

The Division has determined that Weyerhaeuser's proposal to use proper operating practices to minimize the emissions of VOC and CO constitutes BACT. The BACT emission limits have been established as 40 ppm on a dry basis at 8 percent O_2 (as carbon) for VOC and a limit of 300 ppm on a dry basis at 8 percent O_2 for CO. The facility will be required to conduct performance testing and establish a minimum flue gas O_2 concentration that demonstrates compliance with the limits. The facility will be required to monitor O_2 concentration on a continuous basis and report excursions to the Division.

Summary – VOC and CO Control Technology Review for Recovery Boiler U500

To fulfill the PSD permitting requirements for VOC and CO, a BACT analysis was conducted for the modified recovery boiler. The BACT selection for the boiler is summarized in Table 6.

Table 6: BACT Summary for the Proposed Modified Recovery Boiler U500

Pollutant	Control Technology	Proposed BACT Limit
VOC	Good Operating Practices	40 ppm on a dry basis at 8% O_2 (as carbon)
CO	Good Operating Practices	300 ppm on a dry basis at 8% O_2

Recovery Boiler – SO_2

SO_2 emissions from the recovery boiler primarily result from the oxidation of TRS. However, as previously noted, the chemical recovery process scrubs out most of the SO_2 emissions from the exhaust fume. Additional SO_2 emissions result from the oxidation of sulfur in the fuel oil during the combustion process. Uncontrolled SO_2 emissions almost entirely depend upon the sulfur content of the fuel and are not dependent upon boiler properties such as size, burner design, or fuel grade. The majority of the fuel sulfur released is in the form of SO_2.

Step 1: Identify all control technologies

Candidate control options identified from the RBLC search and the literature review include those classified as both pollution prevention and pollution reduction techniques.

Option 1: Wet Scrubber (Dual-Alkali)
Option 2: Spray Dryer with an ESP
Option 3: High Solids Firing
Option 4: Good Operating Practices

Wet Scrubber

In dual-alkali (caustic) scrubbing, a solution of sodium hydroxide absorbs SO_2 from the flue gas. The SO_2 reacts with the sodium hydroxide and is removed in solution as a liquid waste. Additional scrubbing solution is added to the recirculating scrubber solution to compensate for the quantity that reacts with SO_2. Typically, large quantities of liquid waste are disposed of by wastewater treatment holding ponds or are fed back into the weak liquor process where the sulfur can be recovered.

Spray Dryer with an ESP

This technique requires installation of a spray dryer and an ESP. A lime slurry or dry lime is injected by a spray dryer into the flue gas in the form of fine droplets under well controlled conditions such that the droplets will absorb SO_2 from the flue gas and then become dry particles because of the evaporation of water. The dry particles are captured by the ESP downstream of the dryer. The captured particles are then removed from the system and disposed.

High Solids Firing

The formation of SO_2 is minimized by proper chemical recovery operation, which can include firing of black liquor with a high dry solids content and controlling the sulfidity of the liquor. NO_X emissions will increase with firing of higher solids content liquors.

Good Operating Practices

Good operating practices imply that the recovery boiler is operated within parameters that, without significant control technology, allow the equipment to operate as efficiently as possible. Good operating practices also include minimization of the time that the recovery boiler is fired on fuel oil only (e.g., periods without co-firing black liquor solids).

Step 2: Eliminate technically infeasible options

Option 2: Spray Dryer with an ESP

The spray dryer system operation is based on the feasibility of injecting lime into the flue gas. For a chemical recovery boiler, such injection is not feasible. Dust from the recovery boiler flue gas is captured by the ESP and returned to the chemical recovery process. Introduction of lime into the flue gas will disrupt the recycle and chemical balance of the process.

Step 3: Rank remaining control technologies by control effectiveness

Table 7: Ranking of Control Technology

Control Technology Ranking	Control Technology	Control Efficiency
1	Wet Scrubber (Dual-Alkali)	~65%
2	High Solids Firing	7%*
3	Proper Operating Practices	N/a

*Based on an increase from 67% solids to 74.5% solids.

Step 4: Evaluate most effective controls and document

Wet Scrubber

While usage of a wet scrubber system for a recovery boiler is not prohibitive from a purely technical perspective, Weyerhaeuser has stated that this technology has not been successfully demonstrated on nondirect contact recovery boilers anywhere in the United States. Recovery boilers are by definition sulfur recovery units such that a well designed and properly operated recovery boiler emits little SO_2. Weyerhaeuser has stated that the pulp and paper industry has spent the last half century designing increasingly complex and efficient black liquor combustion systems (culminating in the modern nondirect contact systems) to achieve this result as well as to reduce odorous TRS emissions. The typical vendor guarantee for SO_2 is equivalent to an expectation of zero steady state SO_2 emissions while still accounting for basically uncontrolled, highly sporadic, unpredictable, and short duration "spikes" in SO_2 emissions. These spikes can be theoretically traced back to dozens of potential causes, with variations in black liquor sulfidity and solids content being the best characterized and understood. Thus, a scrubber would not actually remove much SO_2 and would be economically infeasible.

Furthermore, usage of a wet scrubber poses environmental problems, which deny its use as environmentally infeasible. The wet scrubber would require additional fresh water; under the Project XL agreement, Weyerhaeuser has a goal of reducing fresh water usage. Further, usage of the wet scrubber would add a highly visible wet plume to the plant site, while the current dry system helps make the mill "invisible" under most weather conditions. Therefore, a wet scrubber system is eliminated from BACT consideration.

High Solids Firing

As previously noted, usage of higher solids content in the black liquor will reduce SO_2 emissions but increase NO_X emissions. Weyerhaeuser obtained preliminary estimates from the boiler vendor estimate that a change from the current 67 percent solids content up to 74.5 percent solids content may decrease SO_2 emissions by as much as 5 ppm but increase NO_X emissions by 5 ppm. This option is eliminated from BACT consideration because of the forecasted impact on NO_X emissions from the Weyerhaeuser recovery boiler.

Step 5: Select BACT

Weyerhaeuser is proposing an SO_2 BACT emission limit ratioed on the heat input contributions of black liquor solids and fuel oil. When firing only black liquor solids, a limit of 75 ppm on a dry basis at 8% O_2 (equivalent to 1.88 lb/ton BLS) would apply. This limit is equivalent to the recent BACT determination for Weyerhaeuser's Marlboro, South Carolina Mill in 2002. While the 75 ppm limit is not as low as the 2001 Longview Fibre limit of 60 ppm, Weyerhaeuser is requesting a slightly higher SO_2 limit in order to achieve lower NO_X emissions. It should be noted that Longview's NO_X limit is higher than the limit proposed by Weyerhaeuser. This SO_2 limit will be achieved through the proper design and operation of the boiler.

When the heat input contribution from fuel oil is large, the recovery boiler achieves little or no SO_2 emissions reductions as the chemical recovery process is limited or not occurring and the soda fume may not be present. Therefore, a higher emission limit is necessary for those infrequent periods when much of the heat input is derived from fuel oil with limited or no black liquor solids co-firing. Such periods include startups and shutdowns as well as periods when no black liquor is available for combustion or very little black liquor is available due to process upsets upstream of the recovery boiler. These periods are minimized as the Weyerhaeuser mill cannot continue to produce pulp without the on-going chemical recovery process provided by this boiler (such periods of operation are not sustainable if the mill is to maintain profitability and meet customer demands). Further, periods of significant fuel oil firing are minimized via the 10 percent fuel oil annual capacity limit in place for the recovery boiler.

Weyerhaeuser's current operating permit contains a 400 ppm SO_2 emission limit that was established to cover periods of exclusive fuel oil firing or periods of limited black liquor solids firing. Weyerhaeuser requests that the 400 ppm at 8 percent O_2 limit be maintained on a 12-hour average for periods of fuel oil only combustion. For scenarios when both fuel oil and black liquor solids are co-fired, the emission limit would be based on the following equation:

E = (75 ppm * Hb + 400 ppm * Hfo) / (Hb + Hfo)

where: E = SO_2 emission limit in ppm on a dry basis at 8% O_2
Hb = heat input, in MMBtu, from black liquor solids firing
Hfo = heat input, in MMBtu, from fuel oil firing

Finally, Weyerhaeuser will meet the 30-day average 40 CFR 60 Subpart Db SO_2 emission limit of 0.5 lb/MMBtu of fuel fired. For simplicity in demonstrating compliance, Weyerhaeuser will demonstrate compliance with this emission limit for all fuel firing periods (e.g., including the SO_2 contribution from the black liquor solids firing).

The following table summarizes SO_2 emission limits that are lower than that proposed by Weyerhaeuser. However, this data also illustrates that lower SO_2 limits are generally associated with higher NO_X limits. Also, the data shows that where SO_2 and NO_X limits are lower the facility used a control technology that is not feasible for the Weyerhaeuser recovery boiler.

Table 8: SO_2 Limit Comparison for Recovery Boilers

Facility and Date	SO_2 Limit*	NO_X Limit	Weyerhaeuser Proposed NO_X Limit	Notes
Meadwestvaco, KY 2002	8%	2.0 lb/ton BLS	100 ppm; 1.88 lb/ton BLS; 0.159 lb/MMBtu; 3.52 lb/T ADP	Wet Scrubber used for SO_2 control. Technology not feasible for Weyerhaeuser.
GP Port Hudson, LA 2002	96%	2.4 lb/ton BLS		None.
	92%	2.3 lb/ton BLS		None.
Longview Fibre, WA 2001	80%	2.07 lb/ton BLS		New facility.
	80%	2.06 lb/ton BLS		New facility.
	80%	2.06 lb/ton BLS		New facility.
Apple Grove, WV 1996	12%	40 ppm		SNCR prescribed for NO_X control. Technology not feasible for Weyerhaeuser. Facility was never built.
James Paper, WA 1991	8%	2.44 lb/T ADP		Heat recovery scrubber used for SO_2 control. Technology not feasible for Weyerhaeuser.
	13%	2.13 lb/T ADP		
Louisiana Pacific, CA 1989	67%	0.1 lb/MMBtu		Facility uses high solids firing. Technology not feasible for Weyerhaeuser.

*As a percentage of the Weyerhaeuser proposal.

Conclusion – SO_2 Control

The Division has determined that Weyerhaeuser's proposal to use proper operating practices to minimize the emissions of SO_2 constitutes BACT. The BACT emission limit has been established according to the equation E = (75 ppm * Hb + 400 ppm * Hfo) / (Hb + Hfo), where: E = SO_2 emission limit in ppm on a dry basis at 8 percent O_2, Hb = heat input, in MMBtu, from black liquor solids firing, and Hfo = heat input, in MMBtu, from fuel oil firing. The facility will be required to conduct performance testing and monitor the emissions with a CEMS.

Summary – SO_2 Control Technology Review for Recovery Boiler U500

To fulfill the PSD permitting requirements for SO_2, a BACT analysis was conducted for the modified recovery boiler. The BACT selection for the boiler is summarized in Table 9.

Table 9: BACT Summary for the Proposed Modified Recovery Boiler U500

Pollutant	Control Technology	Proposed BACT Limit
SO_2	Proper Operating Practices	E = (75 ppm * Hb + 400 ppm * Hfo) / (Hb + Hfo) where: E = SO_2 emission limit in ppm on a dry basis at 8% O_2, Hb = heat input, in MMBtu, from black liquor solids firing, Hfo = heat input, in MMBtu, from fuel oil firing.

Recovery Boiler – NO_X

In the recovery boiler combustion process, NO_X is formed by two fundamentally different mechanisms: fuel NO_X and thermal NO_X.

"Fuel NO_X" forms when the nitrogen compounds bound with the fuel are converted into nitric oxide (NO) at temperatures above 1,600 °F. The amount of bound nitrogen that is converted to fuel NO_X depends upon the fuel type and nitrogen content. Fuel NO_X is dependent primarily on stoichiometric conditions and less on thermal conditions. Due to the rapid conversion, the primary mechanisms for reducing fuel NO_X require creation of a "fuel-rich" zone and reducing available oxygen.

NO_X formed in the high-temperature, post-flame region of the combustion equipment is "thermal NO_X." Thermal NO_X is formed at high temperature by direct oxidation of atmospheric nitrogen and increases exponentially above 2,800 °F flame temperature. Thermal NO_X formation increases with temperature, oxygen and nitrogen concentrations, and residence time. Temperature is the most important factor; thus, temperature reduction is a primary mechanism for reducing thermal NO_X generation.

Technical literature suggests that NO_X formation from the chemical recovery process is primarily fuel NO_X since recovery boiler temperatures are not high enough for thermal NO_X formation. NO_X emissions from recovery boilers are typically low due to the low nitrogen (N) concentration in the black liquor solids (approximately 0.1 percent), the low overall conversion of liquor N to NO_X (10-25 percent) via fuel NO_X formation, insufficient temperatures for thermal NO_X formation (highest recovery boiler temperatures are approximately 2,100 – 2,500 °F), and existence of sodium fumes that can participate in "in-furnace" NO_X reduction or removal.

Step 1: Identify all control technologies

The first of the five steps in the top-down BACT analysis procedure is to identify possible control technologies. Weyerhaeuser obtained information on the various control devices comes from technical journals and industry experience and represents a comprehensive, reasonable listing of control devices for this process.

In a 2003 Special Report, NCASI specifically addressed options for reducing NO_X emissions from recovery boilers, indicating that no operating Kraft recovery boiler currently utilizes post-control combustion and limited pollution prevention techniques are available. Therefore, Weyerhaeuser identified potentially applicable NO_X control technologies for recovery boilers identified based on the principles of control technology and engineering experience, including NO_X control technologies in use or considered for other combustion sources (e.g., industrial boilers).

Pollution Prevention Options
- Option 1: Low Excess Air (LEA)
- Option 2: Staged Combustion
- Option 3: Flue Gas Recirculation (FGR)
- Option 4: Low NO_X Burners (LNB)
- Option 5: Fuel Staging
- Option 6: Good Operating Practices

Pollution Reduction Options
- Option 7: Selective Non-Catalytic Reduction (SNCR)
- Option 8: Selective Catalytic Reduction (SCR)
- Option 9: Non-Selective Catalytic Reduction (NSCR)
- Option 10: Oxidation/Reduction Scrubbing (Ozone Injection)

Low Excess Air

Moderate NO_X reductions can be achieved by lowering the amount of excess air (and thus, excess oxygen) available in the local flame zone. A reduction of 10 to 20 percent for every 1 percent reduction in the oxygen levels is theoretically feasible. Both lower fuel NO_X and thermal NO_X result from operation of a boiler at lower excess air.

Staged Combustion Technologies

Staged combustion technologies such as overfire air (OFA) reduce NO_X emissions by creating a “fuel-rich” zone via air staging (diverting a portion of the total amount of air required through separate ports). Conditions in such a zone result in lower peak temperatures and thus, lower NO_X emissions.

Flue Gas Recirculation

FGR reduces peak flame temperature, minimizing thermal NO_X, by incorporating the recirculation of a portion of the flue gas back into the combustion zone as a replacement for combustion air. The recirculated combustion products provide inert gases that lower the adiabatic flame temperature and overall oxygen concentration in the combustion zone. As a result, FGR limits NO_X emissions by reduction of thermal NO_X only, making it mostly effective for natural gas- or fuel oil-fired boilers.

Low NO_X Burners

Traditional burner design introduces both the fuel and air into one combustion zone. To obtain optimal flames, large amounts of excess air must be combined with the fuel. This relatively “uncontrolled” combustion creates high flame temperatures. To control the generation of thermal NO_X, LNB technology stages combustion in the high temperature zone of the flame. The first stage is a fuel-rich, oxygen-lean atmosphere where little oxygen is available for NO_X formation and which reduces peak flame temperatures by delaying the completion of the combustion process. Combustion is then completed downstream in the second stage where excess air is available but temperatures are lower than the hottest portion of the flame core.

Fuel Staging (Reburning)

Also known as “reburning” or “off-stoichiometric combustion,” fuel staging is a technique where 10 to 20% of the total fuel input is diverted to a second combustion zone downstream of the primary zone. The fuel in the secondary zone serves as a reducing agent: NO formed in the primary combustion zone is reduced to N_2. This technique usually employs natural gas or distillate oil for the fuel in the secondary combustion zone.

Good Operating Practices

The formation of NO_X can be minimized by proper boiler operation and design practices. As discussed previously, NO_X emissions from recovery boilers are low based on the design necessary for the chemical recovery process. However, operators can control the combustion stoichiometry to minimize NO_X formation while achieving efficient fuel combustion.

Selective Non-Catalytic Reduction

SNCR is an exhaust gas treatment process in which urea or ammonia is injected into the exhaust gas. High temperatures, normally between 1,600 and 1,900°F, promote the reaction between urea or ammonia (NH_3) and NO_X to form N_2 and water. The effectiveness of SNCR systems depends upon six main factors: 1) inlet NO_X concentration, 2) temperature, 3) mixing, 4) residence time, 5) reagent-to-NO_X ratio, and 6) fuel sulfur content. Lower NO_X inlet concentrations result in a lower reduction of NO_X. Temperature must fall within the appropriate range to avoid excess ammonia slip or oxidizing of NH_3 to NO_X. Proper mixing of the reagent and the flue gas is necessary to ensure reduction of NO_X. The residence time must be of an appropriate duration to allow completion of the reaction. If the reagent-to-NO_X ratio is too high, excess NH_3 will become present in the exhaust. Finally, if the fuel has a high sulfur content, NH_3 will react with sulfur trioxide to form ammonium sulfate salt compounds.

Selective Catalytic Reduction

SCR is an exhaust gas treatment process in which NH_3 or urea is injected into the exhaust gas upstream of a catalyst bed for exhaust temperatures between 450 and 750°F. The NH_3 or urea reacts to form nitrogen (N_2) and water on the surface of the catalyst. In the SCR process, urea or NH_3 from a liquid storage tank is vaporized and injected into the exhaust prior to the catalyst. The exhaust/ammonia mixture passes over the catalyst. The function of the catalyst is to lower the activation energy of the NO decomposition reaction, therefore, lowering the temperature necessary to carry out the reaction.

The effectiveness of an SCR system depends upon the same factors as the SNCR system and the condition of the catalyst. The catalyst can degrade over time due to poisoning, fouling, thermal stress, and erosion by particulates, reducing the NO_X removal efficiency of the SCR system.

Non-Selective Catalytic Reduction

NSCR is another exhaust gas treatment technique for NO_X reduction. It is the type of catalyst control used to treat automobile exhaust and typically uses a platinum/rhodium catalyst. Use of NSCR reduces emissions of NO_X, CO, and VOC simultaneously across the catalyst bed, but it is only effective in fuel rich combustion air. To achieve a fuel-rich environment, excess combustion air must be kept to a minimum, resulting in an exhaust gas with less than 3 percent oxygen by volume.

Oxidation /Reduction Scrubbing

Several proprietary NO_X removal processes are commercially available. It has been reported that Oxidation/Reduction Scrubbing has a theoretical NO_X removal efficiency of 95 percent. The basic elements of the system are: 1) Cooling of the gas stream to its dew point temperature (150 to 250°F), which condenses a portion of the water vapor in the gas and generates condensate that requires disposal, 2) Low temperature oxidation of the NO_X, CO, and SO_2 to higher oxides through controlled injection of ozone or sodium chlorite in a static mixer or reaction duct (the ozone/NO_X ratios required to produce the desired NO_X oxidation are reported to be less than stoichiometric amounts), 3) Absorption of higher vapor forms of nitrogen and sulfur oxides in a wet scrubber that produces nitric, sulfuric, and carbonic acid solution. These acids must be recovered and neutralized by the use of sodium hydroxide in the scrubber water (caustic scrubbing), and 4) Once neutralized, the resultant scrubber water, containing nitric solution, can be discharged to a sanitary sewer system.

Step 2: Eliminate technically infeasible options

Option 1: Low Excess Air (LEA)

The LEA control option can produce limited NO_X reductions. However, LEA results in the production of smoke, increased CO emissions, and other problems associated with the boiler operation, such as increased corrosion and fouling. This technique also presents technical difficulties for chemical recovery boilers since the primary purpose of the boiler is chemical recovery, not steam production. As a result, air distributions are dictated by the black liquor solids properties. Application of LEA could be detrimental to the chemical recovery process; therefore it is technically infeasible.

Option 3: Flue Gas Recirculation (FGR)

FGR does not significantly reduce NO_X emissions when firing black liquor solids in a recovery boiler since the majority of NO_X emissions arise from fuel nitrogen. Therefore, FGR (which controls thermal NO_X) does not reduce the NO_X emissions from black liquor solids combustion. Further, the corrosive conditions inherent in the firing of black liquor solids prevents the usage of FGR as the fly ash in the flue gas stream would accumulate in the ductwork required for FGR and absorb moisture, resulting in duct pluggage and severe corrosion. Additionally, the reduced oxygen concentration formed in the furnace by FGR would result in an unacceptable increase in CO emissions. The increased flue gas volume would increase gas velocity in the superheaters and boiler bank, which can cause additional pluggage and lost capacity.

Applying FGR as a means of controlling NO_X is considered infeasible and may inhibit the chemical recovery process. FGR has never been demonstrated on a recovery boiler and is not listed in the RBLC Clearinghouse. FGR is considered a technically infeasible control technology.

Option 4: Low NO_X Burners (LNB)

Although Low NO_X burners have been extensively tested and used in utility boilers and industrial furnaces, the transfer of this technology to the chemical recovery process has been met with difficulties. Combustion properties are critical to the quality control and chemical recovery process in the recovery boiler. The fireside conditions in a chemical recovery boiler do not accommodate LNB; usage of LNB would prohibit use of multi-stage air feeds and multiple small fuel nozzles, compromising the burner's intended purpose and impacting their ability to support liquor burning and hearth bed control. Due to these technical complexities, the conversion of a standard recovery boiler burner using black liquor solids or fuel oil to low NO_X design is not technically feasible. Further, no commercially available low NO_X burner is on the market for a recovery boiler application. Low NO_X burners are not technically feasible and cannot be considered BACT for NO_X from a recovery boiler.

Option 5: Fuel Staging

Fuel staging is not appropriate for usage in a chemical recovery boiler. Under normal operation, the boiler combusts only black liquor solids. The black liquor solids cannot be diverted to a second combustion zone without negatively impacting the delicate balance of the chemical recovery process. Usage of fuel staging is generally limited to natural gas or distillate oil combustion. Fuel staging has never been demonstrated on a recovery boiler and is not listed on the RBLC for any recovery boiler. Therefore, fuel staging is considered a technically infeasible control technology for the recovery boiler modification.

Option 7: Selective Non-Catalytic Reduction (SNCR)

Based on trial testing of an SNCR in the early 1990s, several difficulties preclude use of an SNCR for control of NO_X emissions from recovery boilers. The recovery boiler's complex chemical reaction balance can be upset by the SNCR usage, potentially damaging the furnace and negatively impacting product quality. Due to load and exhaust gas temperature fluctuations, optimum NH_3/ NO_X molar ratio, as well as correct reaction temperatures, would be extremely difficult to monitor and maintain, and release of NH_3 into the atmosphere can occur. Further, it is likely that formation of NH_3 salts would occur which could result in an increase of process downtime. In addition, the hazards involved with the storage of NH_3 and the increased emissions from NH_3 slip cause environmental and safety concerns. Finally, the lower furnace area of the recovery boiler may operate at temperatures above 2,000 °F; when temperatures exceed 2,000 °F, the NH_3 injected with the SNCR begins to oxidize, creating additional NO_X.

While SNCR has been demonstrated during a short trial on a recovery boiler (which was decommissioned shortly after the trial concluded), long-term use on an SNCR system has never been evaluated. Theoretically, the ammonia from the SNCR would prevent the chlorine present in the black liquor from being purged through the stack as HCl. Without the purging, the chlorine would build up in the liquor and unreacted ammonia would be lost later in the chemical recovery process, resulting in ammonia emissions from the black liquor mix tank and dissolving tank. The ammonia may also end up in the liquor cycle, increasing the nitrogen content of the black liquor and ultimately increasing the NO_X emissions from the recovery boiler and fouling and plugging the furnace with high chloride deposits.

SNCR has never been demonstrated on a long-term basis and is not listed on the RBLC for any recovery boiler. Therefore, SNCR is considered a technically infeasible control technology for the recovery boiler modification.

Option 8: Selective Catalytic Reduction (SCR)

Several technical and operational difficulties exist with SCR technology. The SCR process is temperature sensitive. Efficient operation requires constant exhaust temperatures within a defined range, usually ± 50°F. Any load fluctuation resulting in exhaust gas temperature fluctuations reduces removal efficiency and upsets the NH_3/NO_X molar ratio. A low temperature results in slow reaction rates which leads to low nitrogen oxides conversion, and unreacted NH_3 passing through the reactor bed (ammonia slip). A high temperature results in shortened catalyst life and can lead to the oxidation of NH_3 and the formation of additional NO_X.

Additional concerns with using a SCR system include the hazards involved with storing large quantities of NH_3 and with disposal of spent catalyst which has been contaminated by SO_2 and Cl_2. The NH_3 also causes potential corrosion problems. Because anhydrous NH_3 used in SCR systems is stored in pressurized vessels, leaks in ammonia supply systems can result in toxic vapor releases. NH_3 transportation, transfer operations, and use can be hazardous because of potential equipment failure and human error.

Controlling the feed rate of the SCR reagent would also present unique technical considerations. The recovery boiler heat input and black liquor solids characteristics vary continuously. Reactant injection rates must be closely controlled to maintain a given level of NO_X control while simultaneously avoiding excess ammonia slip. Such control requires precise knowledge of the boiler's NO_X emission rate, which is directly related to the heat input rate.

The 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, will block the catalyst pores, thereby reducing the catalyst effectiveness.

This technology is not listed for recovery boilers in the RBLC database. SCR is therefore not considered to be BACT for controlling NO_X emissions from recovery boilers.

Option 9: Non-Selective Catalytic Reduction (NSCR)

As noted in the description, usage of NSCR requires maintaining excess air concentrations to less than 3%. The Weyerhaeuser recovery boiler normally operates with stack exhaust gas oxygen concentrations much higher than 3% (by volume). Decreasing the excess air, and thus the O_2 concentrations, would result in increased CO emissions. In addition to the operational incompatibility of the control strategy, various problems will arise from the fuel-borne contaminants causing catalyst fouling (PM_{10}, SO_2, and Cl_2 in the flue gas can poison the catalyst), excessive backpressure, plugging of the catalyst, and efficiency reduction. NSCR is not listed in the RBLC and is technically infeasible for recovery boiler NO_X emissions control.

Option 10: Oxidation/Reduction Scrubbing (Ozone Injection)

This technology is designed to complement control systems that already include a caustic scrubber, which has already been determined as infeasible for the Weyerhaeuser recovery boiler. The high moisture content of black liquor solids results in a high dew point temperature in the flue gas. The flue gas dew point temperature is expected to exceed the 300 °F maximum temperature required for effective oxidation/reduction scrubbing. If the flue gas temperature is lowered to 300 °F, condensation problems and associated high corrosion rates may result.

Due to heavy dust loading upstream of the ESP, the O/R scrubbers must be located downstream of the ESP. Saturated flue gas from the scrubber requires heating before exiting through the flue stack to prevent in-stack condensation of acid gases and other adverse ambient impacts.
Further, bleed air or a water spray cooling tower could be required to cool the gases, thus increasing the size of the ID fan and its power consumption. When using bleed air, cooling the gases to the dew point temperature would condense a portion of the water vapor and acid vapor. This condensate must be properly disposed since it cannot be used in other portions of the chemical recovery process.

Oxygen must be supplied to cells that generate the ozone. This requires installation of very large liquid oxygen tanks. The liquid oxygen is withdrawn from the tank, sent through a vaporizer, and then to the generating cells. Considerable safety practices must be exercised when handling and vaporizing liquid oxygen.

Finally, the ability of the O/R Scrubbing System to perform efficiently on a recovery boiler has not been demonstrated, particularly in the presence of CO_2 from combustion and is not listed for recovery boilers in the RBLC database.

Step 3: Rank remaining control technologies by control effectiveness

Table 10: Ranking of Control Technology

Control Technology Ranking	Control Technology	Control Efficiency
1	Good Operating Practices (Including Staged Combustion)	N/a

Option 6: Good Operating Practices (Including Option 2: Staged Combustion)

Recovery boilers inherently utilize staged combustion practices. The design of the chemical recovery boiler at the Weyerhaeuser facility utilizes multiple levels of air admission into the furnace to control the chemical recovery sodium sulfate reactions and to assure complete combustion of organic compounds. The computerized process control system that regulates this staged combustion process helps minimize the formation of NO_X. Since minimizing the conversion of nitrogen to NO_X can elevate the formation of CO, a balance must be maintained (through the computerized control system) to minimize both NO_X and CO emissions.

Staged combustion can achieve NO_X outlet concentrations of 80 to 120 ppm (corrected to 8 percent oxygen). Several vendors evaluating the Weyerhaeuser recovery boiler have indicated that the boiler already operates with optimized staged combustion and that additional changes may not provide any additional NO_X reductions beyond the present good operating practices. Further, the NO_X emission levels associated with the Weyerhaeuser recovery boiler are well within the 80 to 120 ppm at 8 percent oxygen range expected from optimized staged combustion.

Therefore, for the purposes of this BACT analysis, further changes to the current staged combustion setup are not expected to provide additional control and are eliminated; the present staged combustion practices are considered good operating practices for this recovery unit.

Step 4: Evaluate most effective controls and document

Good operating practices, including staged combustion, are the only remaining control option. Good operating practices and staged combustion are considered BACT for the control of NO_X from recovery furnaces.

Step 5: Select BACT

In addition to the variability in NO_X emissions between different recovery boilers, there is also a significant degree of variability over time with any given recovery boiler in operation. First, NO_X emission rates will vary as the nitrogen and solids content of the black liquor varies. Second the fuel needed to achieve appropriate operating temperatures varies throughout the year, based on the ambient, atmospheric temperature.

As can be seen from Table 6-10 of the application, the values established as BACT are provided in a variety of units and are quite variable. Such variability in presentation of emission limits does not allow for an effective comparison of limits. Note that the variation in NO_X limits also stems from variations in SO_2 and CO emissions limits. To achieve lower NO_X emissions, emission increases of SO_2 and CO emissions will occur.

For the recovery boiler, Weyerhaeuser is proposing a BACT emission limit of 100 ppm on a dry basis at 8 percent O_2 (equivalent to 1.88 lb/ton BLS). The 100 ppm (1.88 lb/ton BLS) limit would be necessary to demonstrate compliance over a 12-hour averaging period. Note that although the boiler at Bowater's South Carolina mill has an 80 ppm at 8 percent O_2 BACT limit, Weyerhaeuser states that combustion properties for recovery boilers are established on a mill-by-mill basis to ensure proper chemical recovery. The proposed limit for the recovery boiler at the Weyerhaeuser mill is based on combustion studies by various recovery boiler vendors and data from the installed NO_X CEMS. Therefore, the 100 ppm at 8 percent O_2 limit is an appropriate limit for NO_X for this recovery boiler, on a 12-hour average. Further, lowering of the NO_X emissions would result in pollutant increases of CO and SO_2.

The following table summarizes NO_X emission limits are lower than that proposed by Weyerhaeuser. The data also shows a trade off where lower NO_X emissions result in higher emissions of SO_2 and CO. It should be noted that the area in which Weyerhaeuser is located is very sensitive to any increase in SO_2 emissions.

Table 11: NO_X Limit Comparison for Recovery Boilers

Facility and Date	NO_X Limit*	Notes
Bowater, SC, 2001	80%	None.
Gulf States, AL, 1997	93%	The CO limit for this plant is about equal to what Weyerhaeuser has proposed and the SO_2 limit for the plant is about 2 times greater than Weyerhaeuser's SO_2 proposal.
Apple Grove, WV, 1996	33%	An SCNR is listed as BACT for the facility. The facility was never built so the technology was not demonstrated.
James River, WA, 1991	69%	The CO limits for the plant are about 3 to 4 times greater than Weyerhaeuser's CO proposal.
James River, WA, 1991	61%	
Leaf River, MS, 1991	80%	The CO limit for this plant is about equal to what Weyerhaeuser has proposed.
Gulf States, AL, 1991	85%	The SO_2 limit for the plant is about 1.3 times greater than Weyerhaeuser's SO_2 proposal.
Longview, WA, 1990	95%	The limits are for a new facility. The CO limit for this plant is about equal to what Weyerhaeuser has proposed and the SO_2 limit for the plant is about 1½ times greater than Weyerhaeuser's SO_2 proposal.
Alabama River, AL, 1990	79%	Although the CO limit for this plant is lower than what Weyerhaeuser has proposed, the SO_2 limit for the plant is about 1½ times greater than Weyerhaeuser's SO_2 proposal.
Weyerhaeuser, MS, 1989	66%	The SO_2 limit for the plant is about 2½ times greater than Weyerhaeuser's SO_2 proposal.
Boise Cascade, ME, 1989	86%	Although the CO limit for this plant is lower than what Weyerhaeuser has proposed, the SO_2 limit for the plant is about 1.3 times greater than Weyerhaeuser's SO_2 proposal.
Boise Cascade, MN, 1989	96%	None.
Georgia Pacific, ME, 1989	80%	Although the CO limit for this plant is lower than what Weyerhaeuser has proposed, the SO_2 limit for the plant is about 2 times greater than Weyerhaeuser's SO_2 proposal.
Louisiana Pacific, CA, 1989	63%	The facility utilizes high solids firing. An increase in high solids firing is not feasible for the Weyerhaeuser plant.
SD Warren, ME, 1988	85%	Although the CO limits for these plants are lower than what Weyerhaeuser has proposed, the SO_2 limits for the plants are about 2 to 3½ times greater than Weyerhaeuser's SO_2 proposal.
Independent, AL, 1983	28%	
Kirby, TX, 1980	46%	
Weyerhaeuser, MS, 1980	70%	The SO_2 limit for the plant is about 1.3 times greater than Weyerhaeuser's SO_2 proposal.
Hammermill, AL, 1980	97%	The SO_2 limit for the plant is about 4½ times greater than the Weyerhaeuser proposal and the CO limit is about 2½ times greater than the Weyerhaeuser proposal.

*As a percentage of the Weyerhaeuser proposal.

Conclusion – NO_X Control

The Division has determined that Weyerhaeuser's proposal to use good operating practices to limit NO_X emissions from the recovery boiler constitutes BACT. The BACT emission limit has been established as 100 ppm on a dry basis at 8 percent O_2. The facility will be required to conduct performance testing monitoring NO_X emissions with a CEMs.

Summary – NO_X Control Technology Review for Recovery Boiler U500

To fulfill the PSD permitting requirements for NO_X, a BACT analysis was conducted for the modified recovery boiler. The BACT selection for the boiler is summarized in Table 12.

Table 12: BACT Summary for the Proposed Modified Recovery Boiler U500

Pollutant	Control Technology	Proposed BACT Limit	Averaging Period
NO_X	Good Operating Practices (Including Staged Combustion)	100 ppm on a dry basis at 8% O_2	12-hours

Recovery Boiler – TRS

TRS emissions are composed primarily of hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide. The major source of hydrogen sulfide is the reaction between the sodium sulfide in the black liquor and the carbon dioxide in the recovery boiler exhaust, although non-direct contact evaporator (NDCE) recovery boiler designs minimize the hydrogen sulfide formation. Methyl mercaptan and dimethyl sulfide are formed by the reactions with the wood lignin, while dimethyl disulfide is formed through the oxidation of mercaptan groups derived from the lignin. The main sources of the methyl mercaptan, dimethyl sulfide, and dimethyl disulfide are the NCGs that are routed to the recovery boiler for combustion. TRS emissions from the recovery boiler can be minimized by avoiding overloading and by maintaining sufficient oxygen, residence time, and turbulence.

Step 1: Identify all control technologies

Weyerhaeuser used the RBLC database and the literature reviews to identify potential TRS control technologies indicated the only potential control technique is good operating practices as the recovery boiler itself is specifically designed to minimize TRS emissions (i.e., a non-direct contact evaporator or low odor design). Good operating practices imply that the recovery boiler is operated within parameters that, without significant control technology, allow the equipment to operate as efficiently as possible.

Option 1: Proper Operating Practices
Option 2: Wet Scrubber

Wet Scrubber
In dual-alkali (caustic) scrubbing, a solution of sodium hydroxide absorbs sulfur compounds from the flue gas. The sulfur compounds react with the sodium hydroxide and are removed in solution as a liquid waste. Additional scrubbing solution is added to the recirculating scrubber solution to compensate for the quantity that reacts with the sulfur compounds. Typically, large quantities of liquid waste are disposed of by wastewater treatment holding ponds or are fed back into the weak liquor process where the sulfur can be recovered.

Step 2: Eliminate technically infeasible options

All options are technically feasible.

Step 3: Rank remaining control technologies by control effectiveness

Table 13: Ranking of Control Technology

Control Technology Ranking	Control Technology	Control Efficiency
2	Wet Scrubbers	~65%
1	Proper Operating Practices	N/a

Step 4: Evaluate most effective controls and document

Wet Scrubber
The wet scrubber would require additional fresh water; under the Project XL agreement, Weyerhaeuser has a goal of reducing fresh water usage. Further, usage of the wet scrubber would add a highly visible wet plume to the plant site, while the current dry system helps make the mill "invisible" under most weather conditions. Therefore, a wet scrubber system is eliminated from BACT consideration. Proper operating practices are the only remaining option.

Step 5: Select BACT

The TRS emission limit achievable by a properly designed and operated recovery boiler can vary due to many factors. Even for similar recovery boilers (in terms of size and fuels), what is achieved in practice can vary significantly, due to the variability of the black liquor solids characteristics and the NCG stream combusted in the recovery boiler. Table 6-12 lists the entries in the RBLC database for recovery boilers and the emission limits approved as BACT in each case for all determinations since 2000. The range of limits reflects the variability in emissions that can exist between different facilities.

In addition to the variability in TRS emissions between different recovery boilers, there is also a significant degree of variability over time with any given recovery boiler in operation. TRS emission rates will vary because the content of the black liquor and the NCG stream varies.

Weyerhaeuser is proposing a TRS emission limit of 5 ppm on a dry basis at 8 percent O_2 as BACT, equivalent to the current NSPS Subpart BB emission limit. This limit will be met using good operating practices for the recovery boiler and is within the lower range of BACT determination presented.

Conclusion – TRS Control

The Division has determined that Weyerhaeuser's proposal to use good operating practices to limit TRS emissions from the recovery boiler constitutes BACT. The BACT emission limit has been established as 5 ppm on a dry basis at 8 percent O_2. The facility will be required to conduct performance testing and monitor TRS emissions with a CEMs.

Summary – TRS Control Technology Review for Recovery Boiler U500

To fulfill the PSD permitting requirements for TRS, a BACT analysis was conducted for the modified recovery boiler. The BACT selection for the boiler is summarized in Table 14.

Table 14: BACT Summary for the Proposed Modified Recovery Boiler U500

Pollutant	Control Technology	Proposed BACT Limit	Averaging Period
TRS	Good Operating Practices	5 ppm on a dry basis at 8% O_2	12-hours

B-Concentrator, Digester Piping and Heat Exchanger, and Wash Press and Filtrate Tank – VOC and TRS

Potential emissions from the digester, concentrator, and wash press with filtrate tank include VOC and TRS. Per the provisions of 40 CFR 60 Subpart BB and 40 CFR 63 Subpart S, all NCG streams from the evaporator and the digester are required to be collected and incinerated in a lime kiln or equivalent point such as a recovery boiler or power boiler. Accordingly, gases discharged from the B-concentrator and the digester are presently collected along with the other strong NCG streams from the various pulping units at the mill and are then incinerated.

The proposed wash press and filtrate tank meet the definition of a washer system as defined by 40 CFR 63 Subpart S and exhaust gases from these units must be collected as part of the weak NCG system and incinerated.

The VOC and TRS BACT analysis for the B-concentrator and digester is determined to be continued collection and incineration of these gases as is required by 40 CFR 60 Subpart BB and 40 CFR 63 Subpart S. A review of the RBLC database confirmed that the collection and incineration of the NCG gases is BACT for VOC and TRS for emissions from the B-concentrator and digester.

Similarly, Weyerhaeuser proposes that collection of the wash press and filtrate tank exhaust as part of the weak NCG system with subsequent incineration, is sufficient to be deemed BACT for VOC and TRS for the new wash press system. A review of the RBLC database supports the collection and incineration of the NCG gases as BACT.

Summary – VOC and TRS Technology Review for B-Concentrator, Digester Piping and Heat Exchanger, and Wash Press and Filtrate Tank

To fulfill the PSD permitting requirements for VOC and TRS, a BACT analysis was conducted for the B-concentrator, digester piping and heat exchanger, and wash press and filtrate tank. The BACT selection is summarized in Table 15.

Table 15: BACT Summary for the Proposed Modified B-Concentrator and Digester Piping/Heat Exchanger and the New Wash Press and Filtrate Tank

Pollutant	Control Technology	Proposed BACT Limit
VOC and TRS	Incineration of Off-Gases	N/a

5.0 TESTING AND MONITORING REQUIREMENTS

Testing Requirements:

Weyerhaeuser will be required to conduct initial performance testing for PM_{10}, VOC, CO, SO_2, NO_X, TRS, and opacity from the modified recovery boiler. The facility must also conduct performance testing for PM_{10}, TRS, and opacity from the smelt tank due to increase black liquor/smelt throughput. The lime kiln has been tested at maximum capacity; therefore, additional testing is not required. Also, the lime kiln is currently equipped with the devices necessary to demonstrate compliance with the new 24-hour SO2 emission limit. No new performance testing is required for the purposes of this limit.

Monitoring Requirements:

Weyerhaeuser will be required to continuously monitor and record the opacity, SO_2, NO_X, TRS, and O_2 concentrations of the recovery boiler exhaust gas. The total power to the ESP will be required to be monitored and recorded during operation of the recovery furnace to provide a reasonable assurance that the facility is in compliance with the particulate matter limits. The facility will be required to continuously monitor flue oxygen in order to provide a reasonable assurance that the facility is in compliance with the CO and VOC limits. The facility will continue to monitor the smelt tank scrubber for pressure drop and scrubbant flow rate. The facility will also continue to monitor O_2 and SO_2 to determine compliance with the new 24-hour SO_2 limit.

CAM Applicability:

The modified recovery boiler is subject to the requirements of compliance assurance monitoring (CAM) as specified in 40 CFR 64. CAM is only applicable to emission units that have potential emissions greater than the major source threshold, located at a major source, use a control device to control a pollutant emitted in an amount greater than the major source threshold for that pollutant, and have a specific emission standard for that pollutant. The recovery boiler uses an ESP to control PM emissions

Pre-controlled PM emissions from the recovery boiler exceed the major source threshold of 100 tpy and are subject to an emission standard under Georgia Rule (e), 40 CFR 60 Subpart BB, 40 CFR 63 Subpart MM, and PSD BACT. Thus, the recovery boiler meets the definition of a subject unit.

The CAM requirements do provide an exemption: if the emission unit is subject to emission limits or standards under 40 CFR Part 60 or 40 CFR Part 63 proposed after November 15, 1990, the unit is exempt from CAM for those emissions. 40 CFR 63 Subpart MM was proposed on April 15, 1998; however, the recovery boiler cannot be exempted because it is also subject to the same limit under PSD BACT.

The frequency of data collection under CAM 64 depends on whether the controlled potential to emit exceeds 100 tons per year [i.e., whether the pseu (pollutant specific emissions unit) is a large pseu]. Based on test data, the controlled emissions from the recovery boiler exceed 100 tons per year; therefore the facility is required to collect four or more data values equally spaced over each hour. The data is then used to calculate the applicable averaging period. The facility will meet these requirements by continuously monitoring the ESP and calculating a total power value at least once every 15 minutes and continuously monitoring opacity.

6.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required to determine the ambient impacts associated with the construction and operation of the proposed modifications. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed modifications, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class II or Class I area. NAAQS exist for NO_2, CO, PM_{10}, SO_2, Ozone (O_3), and lead. PSD increments exist for SO_2, NO_2, and PM_{10}.

The proposed project at the Weyerhaeuser mill triggers PSD review for NO_X, CO, SO_2, PM_{10}, VOC, and TRS. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for NO_X, CO, SO_2, and PM_{10}. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in Appendix E of the application and in the additional information packages.

Modeling Requirements

The air quality modeling analysis was conducted in accordance with Appendix W of Title 40 of the Code of Federal Regulations (CFR) §51, *Guideline on Air Quality Models*, and Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*.

The proposed project will cause net emission increases of NO_X, CO, SO_2, PM_{10}, VOC, and TRS that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment. TRS and VOC do not have established PSD modeling significance levels (MSL) (an ambient concentration expressed in either $\mu g/m^3$ or ppm). While TRS does not have established modeling significance levels, it does have an ambient monitoring *de minimis* threshold that is concentration-based. Therefore, TRS modeling was conducted to demonstrate that the project impact is below the ambient monitoring *de minimis* concentration. Modeling is not required for VOC emissions, however, the project will likely have no impact on ozone attainment in the area based on data from the Sumter County monitor and the level of emissions increases. The southeast is generally NO_X limited with respect to ozone formation.

Significance Analysis: Ambient Monitoring Requirements and Source Inventories

Initially, a Significance Analysis is conducted to determine if the NO_X, CO, SO_2, or PM_{10} emissions increases at the Weyerhaeuser mill would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established monitoring significant level (MSL). The MSL for the pollutants of concern are summarized in Table 16.

If a significant impact (i.e., an ambient impact above the MSL) does not result, no further modeling analyses would be completed for that pollutant for NAAQS or PSD Increment. If a significant impact does result, further refined modeling would be completed to demonstrate that the proposed project would not cause or contribute to a violation of the NAAQS or consume more than the available Class II Increment.

Under current U.S. EPA policies, the maximum impacts due to the emissions increases from a project are also assessed against monitoring *de minimis* levels to determine whether pre-construction monitoring should be considered. These monitoring *de minimis* levels are also listed in Table 16. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. This evaluation is required for NO_X, CO, SO_2, PM_{10}, and TRS.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the MSL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the mill with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses.

Table 16: Summary of Modeling Significance Levels

Pollutant	Averaging Period	PSD Significant Impact Level (ug/m^3)	PSD Monitoring Deminimis Concentration (ug/m^3)
PM_{10}	Annual	1	--
	24-Hour	5	10
SO_2	Annual	1	--
	24-Hour	5	13
	3-Hour	25	--
NO_X	Annual	1	14
CO	8-Hour	500	575
	1-Hour	2000	--
TRS	1-Hour	--	10

NAAQS Analysis

The primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of pollutant in the atmosphere, which define the "levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health." Secondary NAAQS define the levels that "protect the public welfare from any known or anticipated adverse effects of a pollutant." The primary and secondary NAAQS, listed in Table 17 below, are equivalent for NO_X, PM_{10}, and SO_2; no secondary NAAQS have been developed for CO.

Table 17: Summary of National Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary (ug/m^3)	Primary / Secondary (ppm)
PM_{10}	Annual	50 / 50	--
	24-Hour	150 / 150	--
SO_2	Annual	--	0.03 / None
	24-Hour	--	0.14 / None
	3-Hour	--	None / 0.5
NO_X	Annual	--	0.053 / 0.053
CO	8-Hour	--	9 / None
	1-Hour	--	35 / None

If the maximum pollutant impact calculated in the Significance Analysis exceeds the MSL at an off-property receptor, a NAAQS analysis is required. The NAAQS analysis would include the potential emissions from all emission units at the Weyerhaeuser mill, except for units that are generally exempt from permitting requirements and are normally operated only in emergency situations. The emissions modeled for this analysis would reflect the results of the BACT analysis for the modified emission units. Mill emissions would then be combined with the allowable emissions of sources included in the regional source inventory. The resulting impacts, added to appropriate background concentrations, would be assessed against the applicable NAAQS to demonstrate compliance. For an annual average NAAQS analysis, the highest modeled concentration among five consecutive years of meteorological data would be assessed, while the highest second-high impact would be assessed for the short-term averaging periods.

PSD Increment Analysis

The PSD Increments were established to "prevent deterioration" of air quality in certain areas of the country where air quality was better than the NAAQS. To achieve this goal, U.S. EPA established PSD Increments for certain pollutants. The sum of the PSD Increment concentration and a baseline concentration defines a "reduced" ambient standard, either lower than or equal to the NAAQS that must be met in an attainment area. Significant deterioration is said to have occurred if the change in emissions occurring since the baseline date results in an off-property impact greater than the PSD Increment (i.e., the increased emissions "consume" more that the available PSD Increment).

U.S. EPA has established PSD Increments for NO_X, SO_2, and PM_{10}; no Increments have been established for CO. The PSD Increments are further broken into Class I, II, and III Increments. The Weyerhaeuser mill is located in a Class II area. The PSD Increments are listed in Table 18.

Table 18: Summary of PSD Increments

Pollutant	Averaging Period	PSD Increment	
		Class I (ug/m^3)	Class II (ug/m^3)
PM_{10}	Annual	4	17
	24-Hour	8	30
SO_2	Annual	2	20
	24-Hour	5	91
	3-Hour	25	512
NO_X	Annual	2.5	25

To demonstrate compliance with the PSD Increments, the Increment-affecting emissions (i.e., all emissions increases or decreases after the appropriate baseline date) from the mill and those sources in the regional inventory would be modeled to demonstrate compliance with the PSD Class II Increment for any pollutant greater than the MSL in the Significance Analysis. For an annual average analysis, the highest incremental impact will be used. For a short-term average analysis, the highest second-high impact will be used.

The determination of whether an emissions change at a given source consumes or expands Increment is based on the source classification (major or minor) and the time the change occurs in relation to baseline dates. The major source baseline date for NO_X is February 8, 1988, and the major source baseline for SO_2 and PM_{10} is January 5, 1976. Emission changes at major sources that occur after the major source baseline dates affect Increment. In contrast, emission changes at minor sources only affect Increment after the minor source baseline date, which is set at the time when the first PSD application is completed in a given area, usually arranged on a county-by-county basis. The minor source baseline dates have been set for NO_X, SO_2, and PM_{10}.

The Weyerhaeuser mill was constructed in 1980 and was a major PSD source at the time the PSD Increment baseline for NO_X was established in 1988. Thus, all emissions changes not otherwise permitted prior to the 1988 NO_X major source baseline date are treated as Increment-affecting. Emissions from only the lime kiln and the increase from the recovery boiler (the only modified combustion unit) at the mill would be represented as Increment-consuming; all other sources of NO_X emissions were constructed prior to the major source baseline date and have not increased NO_X emissions as a result of a physical change that increases capacity. The calciner would be modeled as Increment expanding source (as it has been shutdown). For PM_{10} and SO_2, all existing sources are Increment-consuming and the calciner is Increment-expanding.

Modeling Methodology

Selection of Model

Two levels of air quality dispersion model sophistication exist: screening and refined dispersion modeling. Normally, screening modeling is performed to determine the need for refined modeling. When results from a screening model indicate potentially adverse impacts, a refined modeling analysis is performed. A refined modeling analysis can provide a more accurate estimate of a source's impact and requires more detailed and precise input data than does a screening model. Given the magnitude of emissions increases from the proposed project, refined modeling was relied upon to predict impacts.

The dispersion modeling analyses was conducted using the latest version (02035) of the Industrial Source Complex model (ISCST3) to estimate maximum ground-level concentrations. ISC is a refined, steady-state, multiple source, Gaussian dispersion model and is the preferred model to use for industrial sources in this type of air quality analysis.

For the NAAQS and PSD Increment modeling analyses, the direction-specific building dimensions used as input to the ISCST3 model incorporate the algorithms of the U.S. EPA-sanctioned Building Profile Input Program (BPIP), version 04112. BPIP is designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, the Building Downwash Guidance document, and other related documents.

Treatment of Terrain

Topographical features of the area immediately surrounding the mill are depicted on the area map in Section 2 of the permit application. As shown, the area is essentially flat and no complex terrain (i.e., terrain with ground elevation greater or equal to the stack height of equipment at the mill) is located nearby. Because no complex terrain is located in the modeling domain, an evaluation of terrain types is not warranted for this analysis. ISCST3 was run in regulatory default mode with the elevated terrain option enabled.

Receptor terrain elevations input to the model were those interpolated from Digital Elevation Model (DEM) data obtained from the U.S. Geological Survey (USGS). The DEM data consist of arrays of regularly spaced elevations and correspond to the 1:24,000 scale topographic quadrangle map series. The array elevations are at 30-meter intervals and were interpolated to determine elevations at the defined 100-meter, 500-meter, and 1,000-meter receptor intervals.

Meteorological Data

The PSD dispersion modeling analysis was conducted using 1974 through 1978 preprocessed meteorological data based on surface observations taken from Macon, Georgia (station 03822) and upper air measurements from Centreville, Alabama (station 13861). The anemometer height for surface measurements at Macon during this period was 23 feet (7.01 meters). This data set is preferred by Georgia EPD for ISC modeling of industrial sources in the central, non-coastal Georgia area.

Land Use Analysis

The land type near the mill must be classified as either rural or urban so that appropriate dispersion parameters can be used within ISCST3. Two land classification procedures, one based on land-use procedure and the other based on population density, can be used to determine the appropriate application of urban or rural dispersion coefficients in a modeling analysis. Of the two, U.S. EPA prefers the land-use procedure. The Auer land-use procedure is used in this study.

To define the land-use in the area surrounding the mill using the Auer land-use procedure, a three-km radius circle was drawn about the center of the plant. If the sum of land use types I1 (heavy industrial), I2 (light to moderate industrial), C1 (commercial), R2 (compact new residential) and R3 (compact old residential) is greater than or equal to 50 percent of the area within the radius, then the area should be classified as urban. The area is classified as rural if the sum of the above-mentioned land-use types is less than 50 percent.

Using the Auer land-use procedure, it was determined that the majority of the land area surrounding the mill is undeveloped and undeveloped rural (A3 and A4 classifications), as is shown in Figure 2-1 of the application. Therefore, the land use in the area was classified as rural for the analysis, and rural dispersion coefficients were specified in ISCST3.

Receptor Grids

In the air dispersion modeling analysis, ground-level concentrations were calculated within three Cartesian receptor grids and at receptors placed along the mill area boundary. Note that this boundary is the fence line for all areas other than the southeastern corner, which is bordered by thick woods. This region is a small subset of the expansive area owned by the mill. Although large portions of the property can arguably be considered nonaccessible by the general public, Weyerhaeuser considered impacts at receptors outside of the mill process area but still on-property in this analysis.

The mill area boundary receptors were spaced 100 meters apart starting at an arbitrary point on the boundary. The three Cartesian grids cover a region extending from all edges of the mill area boundary to approximately 10 km from the facility boundary. A fine grid contains 100-meter-spaced receptors extending approximately 1 km from the mill area boundary. A medium grid contains 500-meter-spaced receptors extending approximately 5.5 km from the mill area boundary, and a coarse grid contains 1,000-meter-spaced receptors that extend approximately 11 km from the mill area boundary.

Representation of Emission Sources

Coordinate System

In all PSD modeling analyses input and output files, the location of emission sources, structures, and receptors were represented in the Universal Transverse Mercator (UTM) coordinate system. The UTM grid divides the world into coordinates that are measured in north meters (measured from the equator) and east meters (measured from the central meridian of a particular zone, which is set at 500 km). The central location of the mill is approximately 776 km East and 3,572 km North in Zone 16. Because the area of the mill where structures and emissions units are located is flat, a single base elevation was used in the model data files for all sources. The base elevation for the facility is approximately 320 feet (97.5 meters) above mean sea level.

Source Types and Parameters

The ISCST3 dispersion model allows for emissions units to be represented as point, area, or volume sources. For point sources with unobstructed vertical releases, it is appropriate to use actual stack parameters (i.e., height, diameter, exhaust gas temperature, and gas exit velocity) in the modeling analyses. Each combustion source at the mill has an unobstructed vertical discharge; therefore actual stack parameters were input to ISCST3 to model each combustion source stack as a point source. For the non-combustion sources (other than the smelt dissolving tank), two appropriate area sources were defined for simplicity based on location and appropriate release heights: one for the woodyard and one for the general mill area.

Note that the PM_{10} modeled is condensable and filterable PM_{10}. Condensable PM emissions were estimated based on data from NCASI Technical Bulletin No. 884 for the recovery boiler, power boiler, smelt tank, and lime kiln. Little or no condensable PM is expected from the other modeled sources based on NCASI data. Note that all NO_X emissions were conservatively presumed to be NO_2. That is, the ambient ratio method (ARM) was not employed, resulting in a conservative analysis.

GEP Stack Height Analysis

The U.S. EPA has promulgated stack height regulations that restrict the use of stack heights in excess of "Good Engineering Practice" (GEP) in air dispersion modeling analyses. Under these regulations, that portion of a stack in excess of the GEP height is generally not creditable when modeling to determine source impacts. This requirement essentially prevents the use of excessively tall stacks to reduce groundlevel pollutant concentrations. In general, the lowest GEP stack height for any source is 65 meters by default. The combined boiler stack and the smelt dissolving tank stack have release heights of 350 ft and 230 ft, respectively, above 65 meters. However these two stacks are located adjacent to the boiler house, which is quite large (210 ft tall, 151 ft long, and 104 ft wide), thereby resulting in a GEP above 350 ft. All other point source stacks have release heights below 65 meters. Therefore, all point sources were modeled at their actual release heights.

Class I Area Analysis

Federal Class I areas are regions of special national or regional value from a natural, scenic, recreational, or historic perspective. Class I areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations. U.S. EPA has established policies and procedures that generally restrict consideration of impacts of a PSD source on Class I Increments to facilities that are located near a federal Class I area. Historically, a distance of 100 km has been used to define "near", but more recently, a distance of 200 km has been used for all facilities that do not combust coal. The nearest Class I area to the mill, Okefenokee Wildlife Refuge, is more than 217 km away. The magnitude of the emissions from the proposed project do not warrant a review of impacts at this distance. Therefore no Class I Increment consumption or Air Quality Related Values (AQRV) analyses were performed.

Modeling Results

Tables 19 through 23 show that the proposed project will not cause ambient impacts of NO_X, CO, or PM_{10} above the appropriate MSLs. Because the emissions increases from the proposed project result in ambient impacts less than the MSLs, no further PSD analyses were conducted for these pollutants. However, ambient impacts above the MSLs were predicted for SO_2 for the 3-hour and 24-hour averaging periods, requiring NAAQS and Increment analyses be performed for SO_2. TRS does not have an MSL.

Table 19: NO_X Significance Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	MSL (ug/m^3)	Significant?
NO_X	Annual	1974	776.125	3571.621	0.45	1	No
		1975	775.670	3572.190	0.49	1	No
		1976	776.542	3571.650	0.50	1	No
		1977	775.670	3572.190	0.60	1	No
		1978	776.125	3571.621	0.53	1	No

Table 20: CO Significance Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	MSL (ug/m^3)	Significant?
CO	1-Hour	1974	775.719	3572.477	102.66	2000	No
		1975	775.846	3571.631	88.54	2000	No
		1976	775.500	3572.600	84.27	2000	No
		1977	776.600	3571.500	110.42	2000	No
		1978	776.724	3571.664	105.01	2000	No
	8-Hour	1974	776.100	3571.500	26.73	500	No
		1975	775.674	3571.990	26.33	500	No
		1976	776.624	3571.657	26.25	500	No
		1977	776.724	3571.664	34.62	500	No
		1978	776.824	3571.671	23.94	500	No

Table 21: TRS Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)
TRS	1-Hour	1974	775.719	3572.477	6.51
		1975	775.846	3572.631	5.63
		1976	775.500	3572.600	5.38
		1977	776.600	3571.500	7.01
		1978	776.724	3571.664	6.66

Table 22: PM_{10} Significance Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	MSL (ug/m^3)	Significant?
PM_{10}	24-Hour	1974	776.824	3571.671	3.57	5	No
		1975	776.824	3571.671	3.69	5	No
		1976	775.600	3572.400	3.74	5	No
		1977	776.800	3571.600	4.43	5	No
		1978	776.624	3571.657	3.65	5	No
	Annual	1974	776.624	3571.657	0.79	1	No
		1975	776.624	3571.657	0.81	1	No
		1976	776.624	3571.657	0.86	1	No
		1977	776.624	3571.657	0.78	1	No
		1978	776.624	3571.657	0.77	1	No

Table 23: SO_2 Significance Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	MSL (ug/m^3)	Significant?
SO_2	3-Hour	1974	776.300	3573.400	64.08	25	Yes
		1975	777.712	3572.072	50.00	25	Yes
		1976	775.726	3571.593	63.62	25	Yes
		1977	775.100	3571.600	56.18	25	Yes
		1978	775.300	3573.400	45.99	25	Yes
	24-Hour	1974	776.200	3573.700	12.12	5	Yes
		1975	775.726	3571.593	17.40	5	Yes
		1976	778.700	3573.400	12.11	5	Yes
		1977	773.600	3574.500	10.69	5	Yes
		1978	776.300	3573.400	11.65	5	Yes
	Annual	1974	781.100	3569.000	0.55	1	No
		1975	772.100	3572.000	0.54	1	No
		1976	781.600	3568.000	0.52	1	No
		1977	772.100	3572.000	0.60	1	No
		1978	772.100	3572.000	0.59	1	No

It should be noted that the initial modeling package submitted by Weyerhaeuser did not indicate SO_2 impacts above the MSL. This was because the modeling did not include the upper bound for SO_2 emission from the recovery boiler (400 ppm at 8 percent oxygen). When the maximum emission rate from this unit was included in the analysis the MSL for SO_2 was exceeded. Weyerhaeuser then conducted the significant impact area analysis, NAAQS analysis, and the Increment analysis as discussed below. When the EPD reviewed the results for the increment analysis, exceedance of the 24-hour limits for SO_2 was discovered in a area to the southwest of the Weyerhaeuser property. Weyerhaeuser determined that the exceedances were due to the short-term emission SO_2 emission rates from the existing lime kiln. This potential emission rates was high due to spiking that would occur when NCGs were burned in the unit. Weyerhaeuser has accepted a 24-hour limit of 260 ppm SO_2 at 10 percent oxygen to limit the potential emission from the lime kiln. The project is in compliance with the NAAQS and the Increment Analysis with the inclusion of this limit.

Significant Impact Area and Regional Inventory

The first step in completing the NAAQS and Increment analyses was the determination of the Significant Impact Area (SIA). The SIA encompasses a circle centered on the mill (in this case, the recovery boiler stack) with a radius extending out to the (1) furthest locations where emissions increases cause a significant ambient impact, or (2) a distance of 50 km, whichever is less. Based on the Significance Analysis results, the SIA was determined to be approximately 15 km.

NAAQS and Increment Modeling

The next step in completing the NAAQS and Increment analyses was the development of a regional source inventory. Nearby sources that have the potential to contribute significantly within the mill’s SIA are ideally included in this regional inventory. Weyerhaeuser requested and received an inventory of NAAQS and PSD Increment sources from Georgia EPD. Weyerhaeuser reviewed the data received and calculated the distance from the mill to each facility in the inventory. All sources more than 50 km outside the SIA were excluded.

For sources within 50 km of the SIA, Weyerhaeuser conducted a permit review to determine the potential SO_2 emissions (the NAAQS inventory provided by EPD shows actual 2002 SO_2 emissions). Upon determination of the potential emissions, the "20D" rule was applied to screen out insignificant sources. Using this screening technique, any source outside the SIA was excluded from the inventory if that entire facility's emissions (tpy) were less than 20 times the distance from the facility to the nearest edge of the impact area (km). Then, any Increment consumers from the provided inventory were added to the NAAQS inventory, if missing. Finally, emission source parameters were verified using the Title V permit application forms or other readily available permitting information. Because most of the sources included in the NAAQS inventory are also Increment consumers, Weyerhaeuser elected to simplify the modeling analyses by using only one regional inventory. By using only one inventory for both the NAAQS and Increment analyses, the impacts predicted are conservative and will be overestimates of the Increment impacts. The regional source inventory is presented in the application.

NAAQS Analysis

In the NAAQS analysis, impacts within the mill's SIA due to the potential emissions from all sources at the mill and those sources included in the regional inventory were calculated. Since the modeled ambient air concentrations only reflect impacts from industrial sources, a "background" concentration was added to the modeled concentrations prior to assessing compliance with the NAAQS. The background concentrations used in the analysis were 93, 39, and 7 µg/m^3 for the 3-hour, 24-hour, and annual averaging periods, respectively.

The results of the NAAQS analysis are shown in Table 24. For the short-term averaging periods, the impacts are the highest second-high impacts. For the annual averaging period, the impacts are the highest impact. Since the total impacts at all significant receptors within the SIA are below the corresponding NAAQS, compliance is demonstrated.

Table 24: SO_2 NAAQS Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Background (ug/m^3)	Total Impact (ug/m^3)	NAAQS (ug/m^3)	Exceed NAAQS?
SO_2	3-Hour	1974	776.125	3571.621	291.87	93	384.87	1300	No
		1975	776.100	3571.600	275.33	93	368.33	1300	No
		1976	776.125	3571.621	318.03	93	411.03	1300	No
		1977	776.125	3571.621	307.23	93	400.23	1300	No
		1978	776.125	3571.621	322.65	93	415.65	1300	No
	24-Hour	1974	773.238	3562.938	76.97	39	115.97	365	No
		1975	773.288	3563.033	87.35	39	126.35	365	No
		1976	773.238	3562.773	87.69	39	126.69	365	No
		1977	776.125	3571.621	82.06	39	121.06	365	No
		1978	773.017	3562.702	87.50	39	126.50	365	No
	Annual	1974	773.238	3562.915	12.95	7	19.95	80	No
		1975	773.238	3563.033	12.67	7	19.67	80	No
		1976	773.238	3562.938	13.44	7	20.44	80	No
		1977	773.238	3562.938	12.41	7	19.41	80	No
		1978	773.263	3563.033	12.16	7	19.16	80	No

Increment Analysis

As noted previously, Weyerhaeuser elected to conservatively assume the NAAQS inventory was equivalent to the Increment inventory. Therefore, the modeled impacts from the NAAQS run were evaluated to determine whether compliance with the Increment was demonstrated. The results are presented in Table 25. Table 25 demonstrates that the impacts are below the appropriate Increments for each of the three averaging periods even with the conservative modeling assumption that all NAAQS sources were Increment sources.

Table 25: SO_2 Increment Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Increment (ug/m^3)	Exceed Increment?
SO_2	3-Hour	1974	776.125	3571.621	291.87	512	No
		1975	776.100	3571.600	275.33	512	No
		1976	776.125	3571.621	318.03	512	No
		1977	776.125	3571.621	307.23	512	No
		1978	776.125	3571.621	322.65	512	No
	24-Hour	1974	773.238	3562.938	76.97	91	No
		1975	773.288	3563.033	87.35	91	No
		1976	773.238	3562.773	87.69	91	No
		1977	776.125	3571.621	82.06	91	No
		1978	773.017	3562.702	87.50	91	No
	Annual	1974	773.238	3562.915	12.95	20	No
		1975	773.238	3563.033	12.67	20	No
		1976	773.238	3562.938	13.44	20	No
		1977	773.238	3562.938	12.41	20	No
		1978	773.263	3563.033	12.16	20	No

Ambient Monitoring Requirements

The impacts quantified in Tables 19, 20, 22, and 23 the Significance Analysis for NO_X, CO, SO_2, and PM_{10} and the TRS impacts in Table 21 are compared to the Monitoring *De Minimis* Concentration, shown in Table 16, to determine if ambient monitoring requirements need to be considered as part of this permit action. As the *de minimis* concentrations for NO_X, CO, and PM_{10} are greater than the MSLs and all modeled impacts were below the MSLs, all modeled impacts were below the monitoring *de minimis* concentration.

The1975 impact for SO_2 shown in Table 23 is slightly higher than the *de minimis* concentration of 13 μg/m^3 for the 24-hour averaging period (no other SO_2 averaging periods have *de minimis* concentrations). However, the Division is confident in the ability of the monitoring stations located at Columbus and Macon to adequately represent ambient air quality in the vicinity of the Weyerhaeuser facility. These monitoring stations will continue to function, collection SO_2 monitored concentration data throughout the implementation period of the proposed project. The data collected by these monitoring stations is considered sufficient to demonstrate the project will not cause an excess of any applicable NAAQS or PSD Increment. The TRS impacts shown in Table 21 are below the 10 μg/m^3 *de minimis* concentration. Based on this data, no pre-construction monitoring is required.

As noted previously, the VOC *de minimis* concentration is mass-based (100 tpy) rather than ambient concentration-based (ppm or μg/m^3). VOC project emissions increases exceed 100 tpy; however, the current Georgia EPD ozone monitoring network (which includes monitors in the Columbus and Macon areas as well as Sumter County) will provide sufficient ozone data such that no pre-construction or post-construction ozone monitoring is necessary.

7.0 ADDITIONAL IMPACT ANALYSES

PSD requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of a modification to the facility and an analysis of the air quality impact projected for the area as a result of the general commercial, residential, and other growth associated with the proposed project.

Soils and Vegetation:

The effect of a proposed project's emissions on local soils and vegetation is often addressed through comparison of modeled impacts to the secondary NAAQS. The secondary NAAQS were established to protect general public welfare and the environment. Impacts below the secondary NAAQS are assumed to indicate a lack of adverse impacts on soils and vegetation. As discussed in Part 6.0 of this determination, the modeled ambient impacts associated with the proposed project are below the MSLs. Therefore, no negative impacts on soils and vegetation are anticipated to result from the implementation of the proposed project.

Growth:

The purpose of a growth analysis is to predict how much new growth is likely to occur as a result of the project and the resulting air quality impacts from this growth. No adverse impacts on growth are anticipated from the project since any workforce growth and associated residential and commercial growth that would be associated with the proposed project (expected to be minimal) would not cause a quantifiable impact on the air quality of the area surrounding the facility.

Visibility:

Visibility impairment is any perceptible change in visibility (visual range, contrast, atmospheric color, etc.) from that which would have existed under natural conditions. Poor visibility is caused when fine solid or liquid particles, usually in the form of volatile organics, nitrogen oxides, or sulfur oxides, absorb or scatter light. This light scattering or absorption actually reduces the amount of light received from viewed objects and scatters ambient light in the line of sight. This scattered ambient light appears as haze.

Another form of visibility impairment in the form of plume blight occurs when particles and light-absorbing gases are confined to a single elevated haze layer or coherent plume. Plume blight, a white, gray, or brown plume clearly visible against a background sky or other dark object, usually can be traced to a single source such as a smoke stack.

Georgia's SIP and Georgia *Rules for Air Quality Control* provide no specific prohibitions against visibility impairment other than regulations limiting source opacity and protecting visibility at federally protected Class I areas. To otherwise demonstrate that visibility impairment will not result from continued operation of the mill, the VISCREEN model was used to assess potential impacts on ambient visibility at a so-called "sensitive receptor," the Montezuma Airport (Dr. C P Savage, Sr. Airport), located approximately 7.7 km from the mill. Since there is no ambient visibility protection standard for Class II areas, this analysis is presented for informational purposes only and predicted impacts in excess of screening criteria are not considered "adverse impacts" nor cause further refined analyses to be conducted.

The primary variables that affect whether a plume is visible or not at a certain location are (1) quantity of emissions, (2) types of emissions, (3) relative location of source and observer, and (4) the background visibility range. For this exhaust plume visibility analysis, a Level-1 visibility analysis was performed using the latest version of the EPA VISCREEN model according to the guidelines published in the *Workbook for Plume Visual Impact Screening and Analysis* (EPA-450/4-88-015). The VISCREEN model is designed specifically to determine whether a plume from a facility may be visible from a given vantage point. VISCREEN performs visibility calculations for two assumed plume- viewing backgrounds (horizon sky and a dark terrain object). The model assumes that the terrain object is perfectly black and located adjacent to the plume on the side of the centerline opposite the observer.

In the visibility analysis, the total project NO_X and PM_{10} emissions increases were modeled using the VISCREEN plume visibility model to determine the impacts. For both views inside and outside the Class II area, calculations are performed by the model for the two assumed plume-viewing backgrounds. The VISCREEN model output shows separate tables for inside and outside the Class II area. Each table contains several variables: theta, azi, distance, alpha, critical and actual plume delta E, and critical and actual plume contrast. These variables are defined as:

1. *Theta* – Scattering angle (the angle between direction solar radiation and the line of sight). If the observer is looking directly at the sun, theta equals zero degrees. If the observer is looking away from the sun, theta equals 180 degrees.

2. *Azi* – The azimuthal angle between the line connecting the observer and the line of sight.

3. *Alpha* – The vertical angle between the line of sight and the plume centerline.

4. *delta E* – Used to characterize the perceptibility of a plume on the basis of the color difference between the plume and a viewing background. A delta E of less than 2.0 signifies that the plume is not perceptible.

5. *Contrast* – The contrast at a given wavelength of two colored objects such as plume/sky or plume/terrain.

The analysis is generally considered satisfactory if *delta E* and *Contrast* are less than critical values of 2.0 and 0.05, respectively, both of which are Class I, not Class II, area thresholds. The Division has reviewed the VISCREEN results presented in the permit application and have determined that the visual impact criteria (*delta E* and *Contrast*) inside the Montezuma Airport are not exceeded as a result of the proposed project. Since the project passes the Level-1 analysis for a Class I area for the Class II area of interest, no further analysis of exhaust plume visibility is required as part of this air quality analysis.

Georgia Toxic Air Pollutant Modeling Analysis

Georgia EPD regulates the emissions of toxic air pollutant (TAP) emissions through a program covered by the provisions of *Georgia Rules for Air Quality Control*, 391-3-1-.02(2)(a)3.(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the Georgia EPD's review of TAP emissions as part of air permit reviews are contained in the agency's "*Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*." The *Guideline* implies that a pollutant is identified as a toxic air pollutant if any of the following toxicity determined values have been established for that pollutant:

- U.S. EPA Integrated Risk Information System (IRIS) reference concentration (RfC) or unit risk
- Occupational Safety and Health Administration (OSHA) Permissible Exposure Limits (PEL)
- American Conference of Governmental Industrial Hygienists (ACGIH) Threshold Limit Values (TLV)
- National Institute for Occupational Safety and Health (NIOSH) Recommended Exposure Limits (REL)
- Lethal Dose –50% (LD_{50}) Standards

Selection of Toxic Air Pollutants for Modeling

For projects with quantifiable increases in TAP emissions, an air dispersion modeling analysis is generally performed to demonstrate that off-property impacts are less than the established Acceptable Ambient Concentration (AAC) values. The TAP evaluated are restricted to those that may increase due to the proposed project. Thus, the TAP analysis would generally be an assessment of off-property impacts due to mill-wide emissions of any TAP emitted by a mill. To conduct a mill-wide TAP impact evaluation for any pollutant that could conceivably be emitted by the mill is impractical. A literature review would suggest that at least one molecule of hundreds of organic and inorganic chemical compounds could be emitted from the various combustion units. This is understandable given the nature of the black liquor, lime mud, wood, red oil, and NCG gases fed to the combustion sources, and the fact that there are complex chemical reactions and combustion of fuel taking place in some sources (e.g., lime kiln and recovery boiler). The vast majority of compounds potentially emitted however are emitted in only trace amounts that are not reasonably quantifiable.

The emission units at the Weyerhaeuser mill are highly controlled and remain state of the art technology. Since the primary emission units (other than the power boiler) are affected sources under NESHAP Subpart MM (Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills), they are held to emissions levels for HAP equivalent to the best performing sources in operation. The recovery boiler and lime kiln are also held to emission standards specified in the NESHAP Subpart S (Pulp and Paper Industry) due to their function as combustion points for the mill's NCG gas stream. As such, although trace emissions of several individual compounds may be present, the overall TAP emissions from these sources can be expected to be low. Further, the power boiler is subject to NESHAP Subpart DDDDD (Industrial-Institutional-Commercial Boilers and Process Heaters) and will be meeting the HAP limits under this standard by September 13, 2007. The remaining mill sources are largely subject to HAP collection and control as part of the site-specific MACT agreement established for NESHAP Subpart S under the mill's Project XL agreement. For this reason, Weyerhaeuser used a customized and reasonable approach with regard to how the TAP modeling analysis is conducted.

The NESHAP for pulp and paper mill chemical recovery combustion sources (Subpart MM) and pulp and paper processes (Subpart S) were carefully developed by U.S. EPA to target pollutants of particular concern that can be emitted from Kraft pulp mill emission units. Careful research and review of toxicity data led to the decision to target specific pollutants. Weyerhaeuser conducted TAP analyses for the proposed project for those compounds identified by U.S. EPA in the development of NESHAP Subparts MM and S, for which there is also published emissions data available. In addition, as several units are combustion points for NCG gases, TRS compounds were included in the TAP analysis. This subset of compounds to be evaluated is detailed in the following paragraphs.

Subpart MM identified eleven particulate matter HAPs as being warranted for regulation: Antimony, Arsenic, Beryllium, Cadmium, Chromium, Cobalt, Lead, Manganese, Mercury, Nickel, and Selenium.

NESHAP Subpart S targets the reduction of specific pollutants generally emitted in the highest quantities from pulp and paper mill operations. The primary pollutants of concern include the following: Acrolein, Acetaldehyde, Chloroform, Formaldehyde, Methanol, Methylene Chloride, Methyl Ethyl Ketone, Phenol, 1,2,4-Trichlorobenzene, and o-Xylene.

The four major TRS constituents are listed as follows: Methyl Mercaptan, Dimethyl Disulfide, Hydrogen Sulfide, and Dimethyl Sulfide.

This list captures all TAP that could be reasonably anticipated to be emitted in quantities that would warrant an evaluation in a dispersion model. This is particularly true in light of the steps that the mill has taken to limit HAP emissions under the Project XL agreement in place. The Project XL agreement for the mill has resulted in a HAP credit balance, meaning the mill captures and destroys more HAP than otherwise required to meet the MACT standards established by U.S. EPA under the two NESHAP. Aside from taking this approach regarding selection of compounds to be reviewed, the TAP analysis was completed consistent with Georgia EPD's *Guideline*. All sources at the mill (with the exception of emergency fire water pump engines, emergency generators, and wastewater treatment plant) were considered in the toxics analysis to demonstrate that there are no adverse impacts resulting from the cumulative effects of multiple point sources of TAP emissions.

This reduced air toxics modeling approach is consistent with the approach approved by Georgia EPD in the October 2002 facility-wide air toxics analysis. It was approved again by Georgia EPD's dispersion modeling group.

Toxic Air Pollutant Emission Rates

The first step in the TAP modeling analysis was to identify NESHAP-regulated TAP emissions from the mill equipment. The following resources were used to estimate TAP emission rates:

- NCASI Technical Bulletins and Guidance Handbooks
- U.S. EPA *AP*-42 emission factors
- Site-specific test data (preferred resource)

Selection of Toxic Air Pollutants for Modeling

For each TAP identified for further analysis, both the short-term and long-term AAC were calculated following the procedures given in Georgia EPD's *Guideline*. Figure 8-3 contains a flow chart of the process for determining long-term and short-term ambient thresholds. Weyerhauesr referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AAC (i.e., 24-hour or 15-minute). The AACs were verified by the EPD.

Determination of Toxic Air Pollutant Impact

The Georgia EPD *Guideline* recommends a tiered approach to model TAP impacts, beginning with screening analyses using SCREEN3, followed by refined modeling, if necessary, with ISCST3 or ISCLT3. For the refined modeling completed, the infrastructure set-up for the SIA analyses was relied upon with appropriate sources added for the TAP modeling. ISCLT3 was not used because U.S. EPA no longer maintains current versions of the model. Note that per the Georgia EPD's *Guidelines*, downwash was not considered in the TAP assessment.

Initial Screening Analysis Technique

Generally, an initial screening analysis is performed in which the total TAP emission rate is modeled from the stack with the lowest effective release height to obtain the maximum ground level concentration (MGLC). Note the MGLC could occur within the mill boundary for this evaluation method. The individual MGLC is obtained and compared to the smallest AAC. Due to the likelihood that this screening would result in the need for further analysis for most TAP, the analyses were initiated with the secondary screening technique.

Secondary Screening Analysis Technique

For those pollutants that do not pass the initial screening modeling, Georgia TAP Modeling Guidelines recommend additional screening prior to using ISCST3 refined modeling. The second screening technique involves modeling the particular pollutants from each appropriate stack and adding the impact results from each of the stacks. The total impact is then compared to the AAC. That is, a unit emission rate of 1 g/s was modeled from each stack (or representative stack). MGLC impacts from the unit emission rate were scaled using the actual emissions of a particular TAP from a particular stack for each of the modeled stacks using the equation shown below. The impacts from each stack for a particular TAP were then added to reach a total impact, which is then compared to the AAC for that pollutant.

$$Q_2/Q_1 \times (X_1) = X_2$$

where:
Q_1 = the modeled stack emission rate (1 g/s)
Q_2 = the emission rate of individual TAP
X_1 = the MGLC for 1 g/s
X_2 = the MGLC for the individual TAP

For those impacts that were smaller than the appropriate AAC, no significant impact is anticipated, and further modeling was not necessary. For those pollutants that indicated a significant impact is possible, refined modeling was performed to further evaluate the potential for significant impacts. The majority of the TAP screen out and do not require additional refined modeling.

Refined Modeling Methodology
For those pollutants indicating a possible significant impact during the secondary screening, a refined modeling analysis was performed using the modeling setup established for the criteria pollutant PSD modeling analysis. The methodology was the same as presented for the PSD modeling analysis except that downwash was excluded from the TAP analysis, per the Georgia *Guideline.* The maximum impacts of all pollutants are below the applicable AAC.

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 2631-193-0013-V-01-4.

Section 1.0 Facility Description

The EPD has included a description of the proposed modifications.

Section 3.0 Requirements for Emission Units

The citation for Condition 3.3.2.a has been modified. The paragraph limits the emission of TRS from the Recovery Boiler to 5 ppm on a dry basis, corrected to 8% oxygen. This was previously a requirement of 40 CFR 60 Subpart BB. The citation has been updated to include reference to 40 CFR 52.21. The limit is now also classified as a BACT limit under PSD.

Condition 3.3.2.b has been modified. The condition limited the emission of particulate matter from the Recovery Boiler to 0.044 grains per dscf corrected to 8% oxygen. This was a requirement under 40 CFR 60 Subpart BB and 40 CFR 63 Subpart MM. The emission limit has been changed to 0.021 grains per dscf and the citation has been updated to include 40 CFR 52.21. The citation has also been updated to note that the PSD limit subsumes the limits prescribed by Subparts BB and MM.

Condition 3.3.2.c has been modified. The condition limited the opacity of emission from the Recovery Boiler to less than 35% and required by 40 CFR 60 Subpart BB. Due to the modification the boiler is now subject to 40 CFR 60 Subpart Db. Subpart Db requires opacity to be limited to less than 20 % (except for one six-minute period per hour of not more than 27% opacity) when burning fuel oil. The condition has been modified to include the fuel oil opacity limit and the citation has been updated to include reference to 40 CFR 60 Subpart Db.

Condition 3.3.2.d has been modified. The condition previously limited the emission of sulfur dioxide emissions from the Recovery Boiler to 400 ppm under the authority of 40 CFR 52.21. The condition has been modified to include the BACT PSD limit that is based on the amount of black liquor solids or fuel oil being fired in the unit. The citation has been modified to indicate that the limit subsumes the limit under 40 CFR 60 Subpart Db.

Condition 3.3.2.e has been added to the permit. The condition requires the facility to limit the emission of sulfur dioxide to 0.5 lb/MMBtu on a 30-day rolling average. This limit is found in 40 CFR 60 Subpart Db. The facility has proposed to comply with the limit regardless of what type of fuel is being fired in the recovery boiler.

Condition 3.3.2.f has been added to the permit. The condition requires the facility to limit the emission of nitrogen oxides to 100 ppm, on a dry basis corrected to 8% oxygen. This new limit is a result of the PSD BACT analysis.

Condition 3.3.2.g has been added to the permit. The condition requires the facility to limit the emission of carbon monoxide to 300 ppm, on a dry basis corrected to 8% oxygen. This new limit is a result of the PSD BACT analysis.

Condition 3.3.2.h has been added to the permit. The condition requires the facility to limit the emission of volatile organic compounds to 40 ppm, on a dry basis corrected to 8% oxygen. This new limit is a result of the PSD BACT analysis.

Condition 3.3.3.g has been added to the permit. The condition requires the facility to limit the emission of sulfur dioxide from the lime kiln to 260 ppm, on a dry basis, corrected to 10 percent oxygen on a 24-hour bases. This new limit is a result of the PSD Increment analysis.

The citation for Condition 3.3.5 has been modified. The condition requires the facility to combust TRS gases from Equipment Group OG01 and OG02 in the Lime Kiln, Recovery Boiler, or Power Boiler as prescribed by 40 CFR 60 Subpart BB. The citation has been updated to include reference to 40 CFR 52.21.

The citation for Condition 3.3.8 has been modified. The condition requires the facility to combust HAP emissions from the LVHC system into the Power Boiler, Recovery Boiler, or Lime Kiln for destruction as prescribed by 40 CFR 63 Subpart S. The citation has been updated to include 40 CFR 52.21.

The citation for Condition 3.3.9 has been modified. The condition requires the facility to combust HAP emissions from the site-specific Cluster Rule sources in the Recovery Boiler or the Power Boiler as prescribed by 40 CFR 63 Subpart S. The citation has been updated to include 40 CFR 52.21 and 40 CFR 63.443(a).

Condition 3.3.9.i has been deleted. The condition requires the facility to combust HAP emissions from the site-specific Cluster Rule sources in the Recovery Boiler or the Power Boiler as prescribed by 40 CFR 63 Subpart S. Paragraph (i) of the condition listed the NaSH storage tank (Source Code U719). The tank is no longer used at the facility.

Condition 3.3.9.j has been added to the permit. The condition requires the facility to include the new wash press and filtrate tank (Source Code P400 and P408) in the list of equipment with vent gases to be destroyed by the Recovery Furnace or the Power Boiler. This is a requirement under 40 CFR 63 Subpart S and 40 CFR 52.21.

Condition 3.3.29 has been added to the permit. The condition requires the facility to comply with all applicable standards, provisions, and requirements of 40 CFR 60 Subpart Db for the operation of the recovery boiler. The NSPS requirement was triggered by the modification being performed on the boiler.

Condition 3.3.30 has been added to the permit. The condition requires the facility to limit the capacity factor for fuel oil fired in the Recovery Boiler to 10% or less. This is a requirement of 40 CFR 60 Subpart Db that allows the facility to avoid monitoring requirements for nitrogen oxides.

Section 4.0 Requirements for Testing

Condition 4.1.3.ff has been added to the permit. The paragraph describes the test method, Method 10, the facility should use to determine carbon monoxide emissions. The facility is subject to a PSD BACT limit for carbon monoxide from the recovery boiler as a result of this modification.

Condition 4.2.1.a has been modified. The paragraph is a list of the combustion units for which the facility operates CEMs. Ongoing performance testing is not required for those pollutants for which the facility operates a CEM. The list for the recovery boiler has been updated to include a NO_X CEMs. It should be noted that the NO_X CEMs has been in place and has been operating for many years for the purposes of emissions tracking. The CEMs must be added to the condition because the facility is now subject to a PSD BACT limit for NO_X.

Condition 4.2.7 has been added to the permit. The condition requires the facility to conduct initial performance testing for particulate matter, opacity, nitrogen oxides, sulfur dioxides, total reduced sulfur, carbon monoxide, and volatile organic compounds from the modified recovery boiler. The testing is necessary to demonstrate compliance with the new PSD BACT and 40 CFR 60 Subpart Db limits and the limits under existing regulations.

Condition 4.2.8 has been added to the permit. The condition requires the facility to retest the recovery boiler after the completion of Phase II of the recovery boiler modifications if the maximum capacity during the testing required by Condition 4.2.7 is less than 90% of the maximum capacity upon completion of Phase II of the proposed modification. This condition ensures that facility demonstrates compliance with the emission limits at a representative operating capacity.

Condition 4.2.9 has been added to the permit. The condition requires the facility to perform initial performance testing for particulate matter, total reduced sulfur, and opacity for the smelt dissolving tanks. The tests are necessary to demonstrate compliance with 40 CFR 63 Subpart MM, 40 CFR 60 Subpart BB, Georgia Rule (e), and Georgia Rule (b) and because smelt throughput for the unit will increase after the recovery boiler modification. The condition also requires a follow-up test if the facility completes Phase II of the recovery boiler project.

Section 5.0 Requirements for Monitoring

Condition 5.1.1 has been modified. The EPD has revised the general template condition since the issuance of the initial Title V permit. The condition has been included to ensure the most up-to-date language is included in the permit.

Condition 5.2.1.c has been modified. The condition is a list of the continuous monitors that the facility must use during operation of the recovery boiler. These monitors include continuous monitors for TRS, oxygen, opacity, and sulfur dioxide. The nitrogen oxide CEM has been added to the list for demonstrating compliance with the new PSD BACT limit. The citation for the condition has been updated to include 40 CFR 60 Subpart Db.

Condition 5.2.2.f has been added to the permit. The paragraph requires the facility to monitor the recovery boiler ESP on a continuous basis. The parameters of concern are the secondary current and secondary voltage for each electrical isolatable section of the ESP. The facility must also calculate the total power for the unit on a continuous basis. Previously the facility was required to monitor this device once per shift. The requirements of CAM (40 CFR 64) now require that this be done on a continuous basis.

Condition 5.2.2.g has been added to the permit. The paragraph requires the facility to monitor the amount of fuel oil burned in the recovery boiler. These records are necessary to demonstrate compliance with the annual capacity limit in Condition 3.3.30 of the permit.

Condition 5.2.3.d has been modified. The condition previously required the facility to monitor the Lime Kiln and Recovery boiler ESPs once per shift. The monitoring of the recovery boiler ESP is now required to be monitored on a continuous basis and has been moved to Condition 5.2.2. Reference to the recovery boiler has been removed.

Condition 5.2.12 has been added to the permit. The condition states that Recovery Boiler U500 is subject to 40 CFR 64 (CAM) for the emission of particulate matter. The facility must comply with CAM for the unit because it is being modified for the expansion project.

Condition 5.2.13 has been added the permit. The condition specifies the performance criteria for ESP total power and opacity monitoring for Recovery Boiler U500. The condition is a requirement of 40 CFR 64. The facility must comply with CAM for the unit because it is being modified for the expansion project. The monitoring provides reasonable assurance that the facility is in compliance with particulate matter limits for the unit.

Condition 5.3.2 has been added the permit. The condition specifies records that must be maintained the facility for the emission of SO_2 from the recover boiler under 40 CFR 60 Subpart Db. The records are necessary to demonstrate compliance with the 30 day rolling SO_2 limit imposed by the subpart.

<u>Section 6.0 Other Recordkeeping and Reporting Requirements</u>

Condition 6.1.7.a(iv) has been modified. The condition requires the facility to report as an excess emission any 12-hour period during which the average TRS concentration from the recovery boiler is in excess of 5 ppm. A typographical error has been corrected to note that the oxygen should be corrected to 8%, not 10%. The citation has been updated to include 40 CFR 52.21.

Condition 6.1.7.a(v) has been modified. The condition requires the facility to report as an excess emission any six-minute period for which the average opacity from the recovery boiler is 35% or greater. The condition has been updated to note that the limit applies only while burning black liquor solids. When fuel oil is burned the facility must comply with the opacity limit under 40 CFR 60 Subpart Db.

Condition 6.1.7.a(vi) has been added to the permit. The condition requires the facility to report as an excess emission any 12-hour period for which the average sulfur dioxide emission rate from the recovery boiler does not comply with the equation found in Condition 3.3.2.d. This is a requirement of 40 CFR 52.21.

Condition 6.1.7.a(xx) has been added to the permit. The condition requires the facility to report as an excess emission any 30 day rolling period during which the average sulfur dioxide emissions from the Recovery Boiler is in excess of 0.5 lb/MMBtu. This is a requirement of 40 CFR 60 Subpart Db.

Condition 6.1.7.a(xxi) has been added to the permit. The condition requires the facility to report as an excess emission any six-minute period during which the average opacity from the Recovery Boiler is in excess of 20 percent while burning any amount of fuel oil. This is a requirement of 40 CFR 60 Subpart Db. The subpart allows for one six-minute period per hour of not more than 27 percent.

Condition 6.1.7.a(xxii) has been added to the permit. The condition requires the facility to report as an excess emission any 12-hour period during which the average nitrogen oxide concentration from the recovery boiler is greater than 100 ppm at 8 percent oxygen. This is a requirement of 40 CFR 52.21.

Condition 6.1.7.a(xxiii) has been added to the permit. The condition requires the facility to report as an excess emission any 24-hour period during which the average sulfur dioxide concentration from the lime kiln is greater than 260 ppm at 10 percent oxygen. This is a requirement of 40 CFR 52.21.

Condition 6.1.7.b(viii) has been added to the permit. The condition requires the facility to report as an exceedance any period of process operation during which the annual capacity factor for oil burned in the recovery boiler exceeds 10 percent. This is a requirement of 40 CFR 60 Subpart Db.

Condition 6.1.7.c(viii) has been modified. The condition required the facility to report as an excursion any three consecutive readings for which the total power for the recovery boiler was less than 75% of the total power determined during the most recent performance test. The facility is now required to monitor the ESP on a continuous basis, therefore an averaging period of 3 hours has been established.

Condition 6.1.7.c(xii) has been added to the permit. The condition requires the facility to report as an excursion any 3-hour period that the flue oxygen concentration is below the value determined in accordance with Condition 4.2.7. The monitoring is conducted to demonstrate compliance with the carbon monoxide and volatile organic compound emission rates.

Condition 6.1.7.d(vii) has been added to the permit. The condition requires the facility to report the annual capacity factor for oil burned in the recovery boiler with the report required by Condition 6.1.4. The records are necessary to confirm that the facility is not subject to any nitrogen oxide limits under 40 CFR 60 Subpart Db.

Condition 6.2.30 has been added to the permit. The condition requires the facility to submit notifications for the initial start up of the modified recovery boiler as required by 40 CFR 60 Subpart Db.

Condition 6.2.31 has been added to permit. The condition requires the facility to record the amount of fuel oil burned in the recovery boiler each day and use the records to calculate the annual capacity factor. These records are required by 40 CFR 60 Subpart Db and are used to ensure that the facility is complying with the subpart.

Condition 6.2.32 has been added to the permit. The condition requires the facility to submit notification for the start of construction for the two phases of modifications. The notifications are used to keep Division personnel up-to-date on the process and to ensure that the facility starts construction in accordance with the requirements of 40 CFR 52.21.

Condition 6.2.33 has been added to the permit. The condition requires the facility to commence construction of the proposed modifications within 18 months of the date of issuance of the permit. This requirement provides a reasonable assurance that the BACT analysis and modeling for the project is up-to-date.

Section 7.0 Other Specific Requirements

Condition 7.14.3 has been added to the permit. The condition requires the facility to decommission Cylinder Mould Decker P400, Cylinder Mould Decker Filtrate Tank P408, and Cylinder Mound Decker Vacuum Pump P409 upon start up of the new Wash Press (Source Code P450) and Filtrate Tank (Source Code P451). The condition provides a reasonable assurance that the facility's potential emissions do not exceed what is calculated in the PSD analysis.

Condition 7.14.4 has been added to the permit. The condition requires the facility to comply with existing permit conditions for Recovery Boiler U500 until such time that the modified boiler is put into service. The facility then must comply with the limits set forth in the PSD BACT analysis.

Attachment B

The NASH tank has been removed form the "Insignificant Activities Based on Emission Levels" table.

APPENDIX A

Draft Revised Title V Operating Permit Weyerhaeuser – Flint River Operations
Oglethorpe (Macon County), Georgia

APPENDIX B

Weyerhaeuser Flint River Operations PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. 15956, dated January 13, 2005
2. Additional Information Package Dated March 10, 2005
3. Additional Information Package Dated April 17, 2005
4. Additional Information Package Dated May 3, 2005
5. Additional Information Package Dated June 20, 2005
6. Additional Information Package Dated July 12, 2005

APPENDIX C

EPD’S PSD Dispersion Modeling and Air Toxics Assessment Review