



ES-10-105

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

July 28, 2010

Mr. Brian J Hug
Deputy Program Manager
Air Quality Planning Program
Air and Radiation Management Administration
Maryland Department of the Environment
1800 Washington Boulevard
Baltimore, MD 21230

Dear Mr. Hug:

Enclosed please find our BART five factor analysis for each BART-eligible unit at the Luke mill. Modeling has demonstrated that the control (2001-2003 data) emissions result in a 3-year average eighth highest delta deciview impact of 2.36dv at Shenandoah National Park (cumulative impact of the three BART units). With the emission control levels proposed in the analysis, the deciview impact drops to 0.78 dv. The emission control levels represent a 90% drop in SO₂ emissions from No. 25 Boiler and NO_x controls, which keep the NO_x emissions to an annual average of 0.40 lb./MMBtu.

These conclusions are based on the five statutory factors required by the Clean Air Act and represent the best BART controls. In a letter dated January 26, 2010, MDE supported these controls and levels by proposing a formal regulation. We support the terms and conditions proposed in those regulations and hope that they will be maintained as MDE moves forward with the BART program.

If you have any questions about the analysis, please contact me at (301) 359-3311, Extension 3262.

Sincerely,

A handwritten signature in black ink, appearing to read 'Ronald E. Paugh'.

Ronald E. Paugh
Asst. Environmental Manager

REP:plt
Enclosure

Five Factor BART Analysis for NewPage Luke Mill



Environment

Prepared for:
NewPage Corporation
NewPage Luke Mill
Luke, MD

Prepared by:
AECOM
Westford, MA
60158068-1
July 30, 2010

Five Factor BART Analysis for NewPage Luke Mill

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Executive Summary

Federal regulations under Title 40 of the Code of Federal Regulations (CFR) Part 51 Appendix Y provide guidance and regulatory authority for the application of Best Available Retrofit Technology (BART) to those existing eligible sources in order to help meet the targets for visibility improvement at designated Class I areas. The Maryland Department of the Environment (MDE) has identified the coal-fired boiler (Power Boiler No. 25), the natural gas-fired boiler (Power Boiler No.26) as well as the No. 3 Recovery Boiler, at NewPage Luke Mill as BART-eligible emission units. The BART rules require that sources that are subject to BART perform a site-specific BART analysis including a control technology review and CALPUFF modeling to assess the visibility impact of the emission units.

This report documents the case-by-case BART analysis conducted for NO_x, SO₂, and PM₁₀ emissions from Power Boilers No. 25 and 26 and No. 3 Recovery Boiler. This analysis addresses the five statutory factors required by Section 169A (g) (7) of the Clean Air Act that states must consider in making BART determinations:

- (1) the costs of compliance,
- (2) the energy and non-air quality environmental impacts of compliance,
- (3) any existing pollution control technology in use at the source,
- (4) the remaining useful life of the source, and
- (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology

The following emission scenarios were evaluated for the Luke Mill BART analysis:

- **Baseline Case (2001-2003 period)** - Maximum daily emissions of SO₂, NO_x as well as particulate matter for Power Boiler No. 25 were provided by NewPage. The maximum daily heat inputs to Power Boiler No. 25 and 26 were also provided. Daily maximum emissions of SO₂ and particulate matter were based on CEMS data and AP-42 emission factors. Maximum daily black liquor solids (BLS) firing rate for No. 3 Recovery Boiler was also provided by NewPage and standard emission factors from the National Council for Air and Stream Improvement (NCASI) were used to calculate emissions of SO₂, NO_x and particulate matter.
- **Control Case** - NO_x, SO₂, and PM₁₀ emissions signature of Power Boiler No. 25 which assumes a 90% reduction in SO₂ emissions from the baseline (via the installation of either a Spray Dryer Absorber or a Circulating Dry Scrubber), reduction in NO_x emissions from 0.99 lb/MMBtu to 0.40 lb/MMBtu (via year-round operation of the existing SNCR¹). The particulate matter emissions for Power Boiler No. 25 remain the same as the baseline as do the SO₂, NO_x and particulate matter emissions for Power Boiler No. 26 and No. 3 Recovery Boiler.

¹ According to Luke Mill's current Title V Operating Permit, an SNCR was installed on Power Boiler No. 25 in the year 2006.

CALPUFF modeling of baseline emissions showed that Power Boiler No. 25, Power Boiler No. 26 and No. 3 Recovery Boiler are subject to BART based on a 3-year average eighth highest delta deciview impact of 2.35 dv at Shenandoah National Park (cumulative impact of the three units). CALPUFF modeling results show that substantial visibility improvement occurs with the implementation of Control Case emission controls. For the control case, the 3-year average eighth highest delta deciview impact at Shenandoah National Park is 0.78 dv.

Therefore, the recommended BART for Power Boiler No. 25 is the installation of add-on SO₂ controls (either a Spray Dryer Absorber or a Circulating Dry Scrubber), year-round operation of the existing SNCR for NO_x control and multicyclones and baghouse for PM control. Burning natural gas, which inherently has low nitrogen, sulfur and ash content, constitutes BART for Power Boiler No. 26. The currently installed two level staged combustion air control system with ESPs constitutes BART for the No. 3 Recovery Boiler.

1.0 Introduction

Federal regulations under Title 40 of the Code of Federal Regulations (CFR) Part 51 Appendix Y provide guidance and regulatory authority for conducting a visibility impairment analysis for designated eligible sources. The program requires the application of Best Available Retrofit Technology (BART) to those existing eligible sources in order to help meet the targets for visibility improvement at designated Class I areas. The BART analysis will be reviewed and used by the Maryland Department of the Environment (MDE) for development of the state's Regional Haze State Implementation Plan (SIP). The MDE has identified the coal-fired boiler (Power Boiler No. 25), the natural gas-fired boiler (Power Boiler No.26) and the No. 3 Recovery Boiler at the NewPage Luke Mill as BART-eligible emission units.

The BART rules require that sources that are subject to BART perform a site-specific BART analysis including a control technology review and CALPUFF modeling to assess the visibility impact of the emission units.

The BART analysis was conducted in accordance with the procedures contained in the Final BART Guidelines published by the USEPA on July 6, 2005 (Federal Register Volume 70, No. 128). Consistent with the BART Guidelines, the five steps for a case-by-case BART analysis were followed:

1. Step 1 – Identify all available control technologies for the affected units including improvements to existing control equipment or installation of new add-on control equipment.
2. Step 2 – Eliminate technically infeasible options considering the commercial availability of the technology, space constraints, operating problems and reliability, and adverse side effects on the rest of the facility.
3. Step 3 – Evaluate the control effectiveness of the remaining technologies based on current pollutant concentrations, flue gas properties and composition, control technology performance, and other factors.
4. Step 4 – Evaluate the annual and incremental costs of each feasible option in accordance with approved EPA methods, as well as the associated energy and non-air quality environmental impacts.
5. Step 5 – Determine the visibility impairment associated with baseline emissions and the visibility improvements provided by the control technologies considered in the engineering analysis (Steps 1 – 4).

The baseline period for BART analysis as specified in 40 CFR 51 is 2001-2003.

The regulation further requires a formal choice of BART based on the above data, plus the degree of improvement in visibility (impacts), which may be reasonably anticipated to result from the installation or implementation of the proposed BART. Economic analysis, remaining useful life of the plant, and impacts on facility operation that are a cost consequence of air pollution control equipment may be considered in the final BART decision-making process.

This report documents the case-by-case BART analysis conducted for SO₂, NO_x and PM emissions from Power Boiler No. 25 and 26, and the No.3 Recovery Boiler at the NewPage Luke Mill. Section 2.0 provides a description of the BART-eligible units and their baseline emissions. Section 3.0 provides a discussion of available SO₂, NO_x and PM control technologies and improvements in emissions of SO₂, NO_x and PM. The available meteorological data and the CALPUFF modeling procedures are described in Sections 4.0 and 5.0, respectively. The results of the visibility improvement modeling using CALPUFF are also presented in Section 5.0, along with the BART recommendation. References are listed in Section 6.0.

2.0 Baseline Data

2.1 Overview of BART Emission Units

The BART-affected emission units at the Luke Mill are the coal-fired boiler (Power Boiler No. 25), the natural gas-fired boiler (Power Boiler No. 26) and the No. 3 Recovery Boiler.

Power Boiler No. 25 – Power Boiler No. 25 burns coal as a primary fuel with natural gas used as a secondary fuel. Built in 1965, this boiler has a nominal rating of 785 MMBtu/hr. The boiler is used as a backup system for incineration of emissions from non-condensable gas (NCG) and stripper off gas (SOG) systems.

Power Boiler No. 26 – Power Boiler No. 26 was installed in 1970 and was converted to natural gas in 1982. With a nominal rating of 338 MMBtu/hr, the boiler is also used as a backup system for incineration of emissions from the NCG and SOG systems.

No. 3 Recovery Boiler – The No. 3 Recovery Boiler is used to recover chemicals from spent pulping liquors and to produce steam for the mill. It fires black liquor as the primary fuel with No. 4 oil used for startup purposes. Installed in 1969, this boiler has a nominal rating of 287,500 pounds of 50% black liquor solids per hour.

2.2 Current Control Technologies

Power Boiler No. 25 – Power Boiler No. 25 has a multi-cyclone mechanical collector in series with a baghouse for control of particulate matter. The boiler is also equipped with an over-fire air system, low-NO_x burners and a selective non-catalytic reduction system for controlling NO_x emissions. Emissions from Power Boiler No. 25 exhaust into a single tall stack which serves as the common emission point for the exhaust streams from Power Boiler Nos. 24, 25 and 26. The combined stack is equipped with CEMS for NO_x, SO_x and flow, and a continuous opacity monitor.

Power Boiler No. 26 – There are currently no emissions controls installed on Power Boiler No. 26. Emissions from Power Boiler No. 26 exhaust into a single tall stack which serves as the common emission point for the exhaust streams from Power Boiler Nos. 24, 25 and 26. The combined stack is equipped with CEMS for NO_x, SO_x and flow, and a continuous opacity monitor.

No. 3 Recovery Boiler – The No. 3 Recovery Boiler has two level staged combustion air control system for the control of SO₂ and NO_x emissions. The boiler flue gases are routed through electrostatic precipitators (ESP1, ESP2 and ESP3) for control of particulates.

2.3 Baseline Emissions

2.3.1 Power Boiler No. 25

Maximum daily SO₂ and NO_x baseline emissions for Power Boiler No. 25 for the baseline period were provided by NewPage. Maximum daily SO₂ emissions during the baseline period were estimated by NewPage to be 40 tons per day. The maximum daily NO_x emissions rate was calculated using an emission factor of 0.99 lb/MMBtu and a daily maximum heat input rate of 761 MMBtu/hr. Based on the stack test conducted on the combined stack in April 2002, AECOM calculated a filterable PM

emission rate of 125 lb/hr from the combined stack and apportioned it to Power Boiler No. 25 using a scaling factor proportional to its rated heat input capacity. Therefore, baseline filterable PM emission rate from the Power Boiler No. 25 was calculated to be 70.8 lb/hr.

Speciation of the particulate matter emissions from Power Boiler No. 25 into filterable and condensable PM₁₀ components was conducted using the following approach:

- Power Boiler No. 25 was equipped with multicyclone back in 2001; therefore, filterable PM was subdivided by size category consistent with the default approach cited in AP-42, Table 1.1-6. For a coal-fired boiler equipped with a multicyclone, 29% of PM emissions are PM₁₀, and 3% are fine PM₁₀ i.e. PM_{2.5}.
- For coal-fired boilers, elemental carbon is expected to be 3.7% of fine filterable PM₁₀ based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
- Condensable PM₁₀ emissions from coal fired boilers are based on AP-42 Table 1.1-5. Total condensable PM₁₀ = 0.01S-0.03 lb/MMBtu, where S is the % sulfur content of coal. Inorganic condensable PM₁₀ is 80% and organic is 20% of total condensable PM₁₀. Inorganic fraction of condensable PM₁₀ emissions is assumed to consist entirely of sulfates (i.e. no soil component).

2.3.2 Power Boiler No. 26

Maximum daily NO_x baseline emission rate of 74 lb/hr was provided by NewPage. Maximum daily SO₂ emission rate was calculated using the AP-42 emission factor given in Table 1.4-2 (0.0006 lb/MMBtu) and the maximum daily heat input rate provided by NewPage. AECOM estimated the filterable PM emission rate using the emission factor given in AP-42 Table 1.4-2 (1.9 lb/MMcf) and the maximum daily heat input to the boiler.

Speciation of the particulate matter emissions from Power Boiler No. 26 into filterable and condensable PM₁₀ components was conducted using the following approach:

- In accordance with AP-42 Section 1.4, for a natural gas fired boiler, 100% of all filterable PM is PM_{2.5} or smaller.
- For natural gas-fired boilers, elemental carbon is expected to be 6.7% of fine filterable PM₁₀ based on the best estimate for natural gas combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
- Condensable PM₁₀ emissions from natural gas-fired boilers are based on AP-42 Table 1.4-2. Total condensable PM₁₀ = 5.7 lb/MMcf. Inorganic condensable PM₁₀ is 50% and organic is 50% of total condensable PM₁₀. Inorganic fraction of condensable PM₁₀ emissions is assumed to consist entirely of sulfates (i.e. no soil component).

2.3.3 No. 3 Recovery Boiler

Maximum daily firing rate of black liquor solids for the baseline period was provided by NewPage. The No. 3 Recovery Boiler is a direct contact evaporator. SO₂, NO_x and PM emissions were calculated using the emission factors given in NCASI Technical Bulletin 884 Table 4.11.

Speciation of the particulate matter emissions from No. 3 Recovery Boiler into filterable and condensable PM₁₀ components was conducted using the following approach:

- For a recovery boiler equipped with an ESP, 76% of filterable PM is PM₁₀ consistent with the default approach cited in AP-42, Table 10.2-2. Fine PM₁₀ (PM_{2.5}) is 53.8 % of filterable PM₁₀.
- Elemental carbon percentage was not available for a black liquor solids fired boiler. Therefore, an oil fired boiler was used as a surrogate. For oil boilers, elemental carbon is expected to be 7.4% of fine filterable PM₁₀ based on the best estimate for oil combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
- Condensable PM₁₀ emissions from No. 3 Recovery Boiler are based on NCASI emission factors documented in Appendix A entitled "Particulate Emissions for Pulp and Paper Industry Specific Sources". Inorganic condensable PM₁₀ emission factor is 1.36 lb/ ton BLS and organic condensable PM₁₀ emission factor is 0.148 lb/ton BLS. Sulfates, based on ion chromatography, are 35% of condensable PM₁₀.

Table 2-1 provides a summary of the SO₂, NO_x, and PM emissions that were used in the modeling analysis for baseline conditions. Table 2-2 provides the stack parameters that were used in the baseline modeling analysis.

Table 2-1 NewPage Luke Mill – Baseline Emissions for Power Boiler No. 25, Power Boiler No. 26 and No. 3 Recovery Boiler

Unit	Maximum Daily Heat Input Rate/ BLS Feed Rate (a)	Units	Fuel	SO ₂ (lb/hr)	NO _x (lb/hr)	Filterable PM (lb/hr)	Total PM ₁₀ Emissions (Filterable + condensable) (lb/hr)	Filterable PM ₁₀ (lb/hr)					Condensable PM ₁₀ (lb/hr)				
								Total FPM	Coarse	Fine Total	Fine Soil	Fine Elemental Carbon	Total CPM	CPM IOR			Total CPM OR
														Total CPM IOR	Soil	Sulfates	
Power Boiler #25	781	MMBtu/hr (a)	Coal	3,333.33 (a)	753.39 (a)	70.8 (a)	197.85	20.53	19.92 (b)	0.62 (b)	0.59 (c)	0.02 (c)	177.31 (d)	141.85 (d)	0.00 (d)	141.85 (d)	35.46 (d)
Power Boiler #26	79	MMBtu/hr (a)	NG	0.05 (a)	74.00 (a)	0.15	0.59	0.15	0.00 (b)	0.15 (b)	0.14 (c)	0.01 (c)	0.44 (d)	0.22 (d)	0.00 (d)	0.22 (d)	0.22 (d)
Combined Stack	840	MMBtu/hr (a)	—	3,333.38	827.39	70.96	198.43	20.68	19.92	0.76	0.73	0.03	177.75	142.07	0.00	142.07	35.68
#3 Recovery boiler	85.42	tons BLS/hr (a)	Liquor, #2 Oil	181.06	93.10	63.21	176.65	48.04	14.03 (e)	34.01 (e)	31.49 (f)	2.62 (f)	128.61 (g)	116.17 (g)	71.06 (g)	46.06 (g)	12.64 (g)

(a) Highest hourly actual emissions based on the maximum daily heat input during the operating period between 2001 and 2003. Max. daily heat input rate for the boilers #25 and #26 provided by NewPage Luke Mill. Max. daily feed rate of dry black liquor solids (2,050 tpd) provided by Ron Raugh in an email dated July 1, 2010. For Boiler 25, SO₂ emissions are based on 40 tons per day and NO_x emissions are based on the permit limit of 0.99 lb/MMBtu and maximum heat input. For Boiler 26, emissions of SO₂ are based on the AP-42 emission factor given in Table 1.4-2 and NO_x is 74 lb/hr. For Boiler 25, filterable PM emissions based on the results April 2002 stack test conducted on the tall stack. FR. PM emissions were apportioned to the Boiler 25 based on its rated heat input.

(b) Boiler #25 had a multi-cyclone back in 2001, therefore size distribution is based on AP-42 Table 1.1-6 for a boiler controlled having a multi-cyclone as a control device. According to AP-42 Table 1.1-6, for a coal fired boiler equipped with a multi-cyclone, 29% of all filterable PM is PM10 and 3% is fine PM10 (i.e. PM2.5). According to AP-42 Section 1.4, for a natural gas fired boiler, 100% of all filterable PM is PM10 and 100% of all filterable PM10 is fine PM10 (less than 1 micron).

(c) 3.7% of fine PM10 is fine EC based on the average of the best estimates for coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002. 6.7% of fine PM10 is fine EC based on the average of the best estimates for natural gas combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002. Fine soil is the balance of fine PM10 total.

(d) Condensable PM₁₀ for coal firing is based on AP-42, Table 1.1-5. Total condensable PM10 = 0.015-0.03 lb/MMBtu. Inorganic is 80% of total and organic is 20% of total. Inorganics assumed to be sulfates (i.e. no soil component). Condensable PM10 for natural gas firing is based on AP-42, Table 1.4-2. Total condensable PM10 = 5.7 lb/MMBtu. Inorganic is assumed to be 50% of total and organic is assumed to be 50% of total. Inorganics assumed to be all sulfates (i.e. no soil component).

(e) For a recovery boiler, based on AP-42, Table 10.2-2 and Figure 10.2-2, 76% of filterable PM is PM₁₀. Fine PM₁₀ is 53.8% of filterable PM₁₀. Coarse PM₁₀ is the difference between total filterable PM₁₀ and fine PM₁₀.

(f) 7.4% of fine PM10 based on the average of the best estimates for petroleum combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002. Fine soil is the balance of fine PM10 total.

(g) Condensable PM10 emissions from recovery boilers are based on NCASI emission factors (Appendix A- Particulate Emissions for Pulp and Paper Industry Specific Sources, February 9, 2006). The emissions factors are 1.36 lb/ton of BLS for CPM IOR and 0.148 lb/ton of BLS for CPM OR. Sulfates, based on ion chromatography, are 35% of the CPM.

Table 2-2 NewPage Luke Mill – Baseline Stack Parameters for Power Boiler No. 25, Power Boiler No. 26 and No. 3 Recovery Boiler

	Stack Information	Stack round or rectangular	Diameter (ft)	Stack height (ft)	Exhaust flow (acfm)	Exhaust temp (°F)	Exhaust velocity (ft/s)
Boilers Combined Stack	One stack for the 2 BART eligible boilers (Boilers 25 & 26)	Round	16.50	623	394,000	373	30.71
Recovery Boiler (3 stacks)	ESP 1	Rectangle	7.94	294	280,000	345	94.28
	ESP 2	Rectangle	8.88	308.5	280,000	345	75.29
	ESP 3	Rectangle	9.03	300	140,000	345	36.46

3.0 Emission Control Alternatives

The control alternatives pertaining to visibility impairing pollutants (NO_x, SO₂, and PM) are discussed in this section. Information on control of these pollutants through application of a control device, combination of devices, and/or operational change is provided in this section.

3.1 Power Boiler No. 25

The following BART control scenario was evaluated for the No. 25 Power Boiler:

- Control Case - NO_x, SO₂, and PM₁₀ emissions signature of Power Boiler No. 25 which assumes a 90% reduction in SO₂ emissions from the baseline (via the installation of either a Spray Dryer Absorber or a Circulating Dry Scrubber), reduction in NO_x emissions from 0.99 lb/MMBtu to 0.40 lb/MMBtu (via operation of the existing SNCR which was installed in 2006) and no change in particulate matter emissions compared to the baseline.

3.1.1 SO₂ Emission Controls

Sulfur dioxide emissions are generated in fossil fuel-fired combustion units as a result of the oxidation of sulfur present in the fuel. Approximately 98% of the sulfur in coal is emitted upon combustion as gaseous sulfur oxides, SO₂ and SO₃. Uncontrolled emissions of SO₂ are directly related to the fuel sulfur content, and not by the firing mechanism, boiler size, or operation. Many coal-fired boilers in the U.S. limit emissions of SO₂ through the use of low sulfur western coals, including Powder River Basin Coal. Compared with higher sulfur eastern bituminous coal that may contain as much as 4% sulfur, the practice of burning western coal can reduce SO₂ emissions by approximately 70% to 90%. However, control equipment such as wet and dry scrubbers can generally remove a higher percentage of the SO₂ from higher sulfur coal than lower sulfur coal. The selection of coal type and sulfur content, therefore, is an important aspect of the determination of BART for SO₂ and needs to be considered in conjunction with add-on control alternatives when performing the BART analysis.

The following SO₂ control option was evaluated for this BART analysis:

- SO₂ Control Case - SO₂ emissions signature of Power Boiler No. 25 which assumes a 90% reduction in SO₂ emissions from the baseline (via the installation of either a Spray Dryer Absorber or a Circulating Dry Scrubber). Emission levels and stack parameters corresponding to this case are shown in Table 3-1 and Table 3-2, respectively.

Alternative add-on control technologies such as Wet Flue Gas Desulfurization (capable of achieving 90-95% control), Lime Dry Scrubber/Fabric Filter (capable of achieving 80 to 90% control) and Dry Sorbent Injection with Trona (capable of achieving approximately 60% control) were not evaluated since they offer relatively low control advantage compared to their annual cost. Moreover, due to NewPage's commitment to the installation of an SO₂ control technology (either a Spray Dryer Absorber (SDA) or a Circulating Dry Scrubber (CDS)); SO₂ emissions are reduced by as much as 90% from baseline levels.

Since this SO₂ control measure has already been committed to be implemented at the facility (see October 31, 2007 letter from Gary Curtis, VP, Luke Operations to Brian Hug of MDE), no further

review of the performance, and economic, energy, and environmental impacts of the control option was necessary.

Table 3-1 NewPage Luke Mill – Emissions Control Case

Unit	Maximum Daily Heat Input Rate/ BLS Feed Rate (a)	Units	Fuel	SO ₂ (lb/hr)	NO _x (lb/hr)	Filterable PM (lb/hr)	Total PM ₁₀ Emissions (filterable + condensible) (lb/hr)	Filterable PM ₁₀ (lb/hr)					Condensable PM ₁₀ (lb/hr)				
								Total FPM	Coarse	Fine Total	Fine Soil	Fine Elemental Carbon	Total CPM	CPM IOR			Total CPM OR
Power Boiler #25	761	MMBtu/hr (a)	Coal	333.3 (a)	304.40 (a)	53.3 (a)	64.23	49.01	23.03 (b)	25.97 (b)	25.01 (c)	0.96 (c)	15.22 (d)	12.18 (d)	0.00 (d)	12.18 (d)	3.04 (d)
Power Boiler #26	79	MMBtu/hr (a)	NG	0.05 (a)	74.00 (a)	0.15	0.59	0.15	0.00 (b)	0.15 (b)	0.14 (c)	0.01 (c)	0.44 (d)	0.22 (d)	0.00 (d)	0.22 (d)	0.22 (d)
Combined Stack	840	MMBtu/hr (a)	—	333.38	378.40	53.42	64.82	49.16	23.03	26.12	26.15	0.97	15.66	12.40	0.00	12.40	3.26
#3 Recovery boiler	86.42	tons BLS/hr (a)	Liquor, #2 Oil	181.08	93.10	63.21	176.85	48.04	14.03 (e)	34.01 (e)	31.49 (f)	2.62 (f)	128.81 (g)	116.17 (g)	71.08 (g)	45.08 (g)	12.64 (g)

(a) Highest hourly actual emissions based on the maximum daily heat input during the operating period between 2001 and 2003. Max. daily heat input rate for the boilers #25 and #26 provided by NewPage Luke Mill. Max. daily feed rate of dry black liquor solids (2,050 tpd) provided by Ron Paugh in an email dated July 1, 2010. For Boiler 25, SO₂ emissions undergo a reduction of 90% from the baseline case and NO_x emissions are based on 0.4 lb/MMBtu. For Boiler 26, emissions of SO₂ and NO_x remain unchanged compared to the baseline. For Boiler 25, future emissions of filterable PM based on 0.07 lb/MMBtu (as documented in the BART Commitment Letter from Mr. Gary Curtis of NewPage to Mr. Brian Hug of MDE).

(b) A baghouse was installed on Boiler #25 in 2007, therefore size distribution is based on AP-42 Table 1.1-6 for a boiler controlled having a baghouse as a control device. According to AP-42 Table 1.1-6, for a coal fired boiler equipped with a baghouse, 92% of all filterable PM is PM₁₀ and 53% is fine PM₁₀. According to AP-42 Section 1.4, for a natural gas fired boiler, 100% of all filterable PM is PM₁₀ and 100% of all filterable PM₁₀ is fine PM₁₀ (less than 1 micron).

(c) 3.7% of fine PM₁₀ is fine EC based on the average of the best estimates for coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002. 6.7% of fine PM₁₀ is fine EC based on the average of the best estimates for natural gas combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002. Fine soil is the balance of fine PM₁₀ total.

(d) Condensable PM₁₀ for coal firing is based on AP-42, Table 1.1-5. Total condensable PM₁₀ = 0.02 lb/MMBtu (since the boiler will have either a SDA or dry scrubber in the future case). Inorganic is assumed to be 80% of total and organic is 20% of total. Inorganics assumed to be sulfates (i.e. no soil component). Condensable PM₁₀ for natural gas firing is based on AP-42, Table 1.4-2. Total condensable PM₁₀ = 5.7 lb/MMBtu. Inorganic is assumed to be 50% of total and organic is assumed to be 50% of total. Inorganics assumed to be all sulfates (i.e. no soil component).

(e) For a recovery boiler, based on AP-42, Table 10.2-2 and Figure 10.2-2, 78% of filterable PM is PM₁₀. Fine PM₁₀ is 53.8% of filterable PM₁₀. Coarse PM₁₀ is the difference between total filterable PM₁₀ and fine PM₁₀.

(f) 7.4% of fine PM₁₀ based on the average of the best estimates for petroleum combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002. Fine soil is the balance of fine PM₁₀ total.

(g) Condensable PM₁₀ emissions from recovery boilers are based on NCASI emission factors (Appendix A- Particulate Emissions for Pulp and Paper Industry Specific Sources, February 9, 2006). The emissions factors are 1.36 lb/ton of BLS for CPM IOR and 0.148 lb/ton of BLS for CPM OR. Sulfates, based on ion chromatography, are 35% of the CPM.

Table 3-2 NewPage Luke Mill – Stack Parameters Control Case

	Stack Information	Stack round or rectangular	Diameter (ft)	Stack height (ft)	Exhaust flow (acfm)	Exhaust temp (°F)	Exhaust velocity (ft/s)
Boilers Combined	One stack for Boilers 25 & 26	Round	16.50	623	394,000	373	30.71
Recovery Boiler (3 stacks)	ESP 1	Rectangle	7.94	294	280,000	345	94.28
	ESP 2	Rectangle	8.88	308.5	280,000	345	75.29
	ESP 3	Rectangle	9.03	300	140,000	345	36.46

3.1.1.1 Discussion of Candidate SO₂ Control Technology

Given the commitment to install either a Spray Dryer Absorber or a Circulating Dry Scrubber to achieve 90% control of SO₂ emissions, no alternative add-on controls were evaluated. Therefore, BART for SO₂ is 90% control compared to the baseline levels i.e. an SO₂ emission rate of 0.44 lb/MMBtu.

3.1.2 NO_x Emission Controls

Nitrogen oxides formed during the combustion of coal are generally classified as either thermal NO_x or fuel-bound NO_x. Thermal NO_x is formed when elemental nitrogen in the combustion air is oxidized at the high temperatures in the primary combustion zone yielding nitrogen oxide (NO) and nitrogen dioxide (NO₂). The rate of formation of thermal NO_x is a function of residence time and free oxygen, and increases exponentially with peak flame temperatures. Thermal NO_x from coal combustion can be effectively controlled by techniques that limit available oxygen or reduce peak flame temperatures in the primary combustion zone. Fuel-bound NO_x is formed by the oxidation of chemically bound nitrogen in the fuel. The rate of formation of fuel-bound NO_x is primarily a function of fuel bound nitrogen content, but may also be affected by fuel/air mixing.

The technologies available to control NO_x from coal-fired boilers include combustion controls, such as low-NO_x burners (LNB) and overfire air (OFA), and post-combustion control techniques, such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR).

Power Boiler No. 25 currently has an SNCR (installed in 2006), low NO_x burners, and overfire air for the control of NO_x emissions during the ozone season.

The technical feasibility and performance levels of the alternative NO_x control technologies are evaluated below in terms of their application to Power Boiler No. 25.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is a process that involves post-combustion removal of NO_x from flue gas utilizing a catalytic reactor. In the SCR process, ammonia injected into the flue gas reacts with NO_x and oxygen to form nitrogen and water vapor. The SCR process converts NO_x to nitrogen and water by the following general reactions:



The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction to about 375 to 750°F, depending on the specific catalyst and other contaminants in the flue gas. The factors affecting SCR performance are catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system.

The SCR system is comprised of a number of subsystems, including the SCR reactor, ammonia injection system, and ammonia storage and delivery system. Typically, the SCR reactor is located downstream of the economizer and upstream of the air pre-heater and the particulate control system.

From the economizer outlet, the flue gas would first pass through a low-pressure ammonia/air injection grid designed to provide optimal mixing of ammonia with flue gas. The ammonia treated flue gas would then flow through the catalyst bed and exit to the air pre-heater. The SCR system for a coal boiler typically uses a fixed bed catalyst in a vertical down-flow, multi-stage reactor.

Reduction catalysts are divided into two groups: base metal, primarily vanadium, platinum or titanium, (lower temperature), and zeolite (higher temperature). Both groups exhibit advantages and disadvantages in terms of operating temperature, ammonia-NO_x ratio, and optimum oxygen concentration. The optimum operating temperature for a vanadium-titanium catalyst system is in the range of 550° to 750°F, which is significantly higher than for platinum catalyst systems. However, the vanadium-titanium catalyst systems begin to break down when operating at temperatures above this range. Operation above the maximum temperature results in oxidation of ammonia to ammonium sulfate and NO_x, thereby actually increasing NO_x emissions.

SCR with ammonia injection technology is a demonstrated, commercially available technology. SCR has been used with other coal-fired boilers; therefore, it is a technically feasible technology for the control of NO_x emissions from Power Boiler No. 25.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction is a post-combustion control technology that involves ammonia or urea injection into the flue gases without the presence of a catalyst. SNCR, similar to SCR, involves the reaction of NO_x with ammonia, where a portion of the NO_x is converted to molecular nitrogen and water. Without the use of a catalyst or supplemental fuel injection, the NO_x reduction reaction temperature must be tightly controlled between 1,600 and 2,200°F (between 1,600 and 1,800°F for optimum efficiency). Below 1,600°F ammonia will not fully react, resulting in un-reacted ammonia that is emitted into the atmosphere, (referred to as ammonia slip). If the temperature rises above 2,200°F, the ammonia added will be oxidized resulting in an increased level of NO_x emissions.

SNCR with ammonia injection technology is a demonstrated, commercially available technology. SNCR has been used with other coal-fired boilers; therefore, SNCR is indeed technically feasible for the control of NO_x emissions from Power Boiler No. 25. However, NO_x removal efficiencies with SNCR are lower than those with SCR, typically ranging from 30 to 50% depending on the combustion process and inlet NO_x concentrations.

In 2006, SNCR was installed on Power Boiler No. 25 for the control of NO_x emissions.

3.1.2.1 Discussion of Candidate NO_x Control Technologies

The NO_x post-combustion control technologies identified for evaluation are SCR and SNCR. Of these technologies, SCR has been demonstrated to be the most effective technology in minimizing NO_x emissions from coal-fired boilers. However, Power Boiler No. 25 already has an SNCR in place for controlling NO_x emissions which offers a control efficiency of ~60% compared to baseline NO_x levels. Therefore, continuous operation of the SNCR system with a rolling 30-day emission rate of 0.40 lb/MMBtu is recommended as BART for Power Boiler No. 25.

3.1.3 PM Emission Control

Power Boiler No. 25 currently employs a multi-cyclones and a fabric filter to control PM emissions. The baseline PM emission rate for Power Boiler No. 25 is 71.4 lb/hr which is well below its permit limit. Moreover, PM emissions are not a significant contributor to the visibility impacts as seen in the

modeling analysis presented in Section 5. Visibility modeling shows that PM emissions have a relatively minor contribution to the overall visibility impacts. Given the high performance level of the existing multi-cyclones and baghouse, these PM control devices are considered BART for Power Boiler No. 25 and no additional PM controls were considered as part of this analysis.

3.2 Power Boiler No. 26

The following BART control scenario was evaluated for the No. 26 Power Boiler:

- Control Case - The current (2009-2010 period) emissions signature of Boiler No. 26 which assumes no change in NO_x, SO₂, and PM₁₀ emissions compared to the baseline.

3.2.1 SO₂ Emission Controls

Sulfur dioxide emissions are generated in fossil fuel-fired combustion units as a result of the oxidation of sulfur present in the fuel. Uncontrolled emissions of SO₂ are directly related to the fuel sulfur content, and are not affected by the firing mechanism, boiler size, or operation. Power Boiler No. 26 is a natural gas fired boiler. Pipeline quality natural gas has a very low sulfur content and hence minimal SO₂ emissions.

The following control option was evaluated for this BART analysis:

- SO₂ Control Case - The current (2009-2010 period) SO₂ emissions signature of Boiler No. 26 which is 0.0006 lb/MMBtu (assumes no change from baseline levels). Emission levels and stack parameters corresponding to this emissions scenario are shown in Table 3-1 and Table 3-2, respectively.

Since Power Boiler No. 26 is a natural gas fired boiler, it has very low emissions of SO₂ (less than 0.1 lb/hr). No add-on emission controls were considered for this unit as any visibility improvement (offered by an add-on control) to the already small visibility impacts would not be cost-effective and hence would not constitute BART.

Hence, BART for SO₂ is the current emissions signature of Power Boiler No. 26, i.e., an SO₂ emission rate of 0.0006 lb/MMBtu.

3.2.2 NO_x Emission Controls

Nitrogen oxides formed during the combustion of fossil fuels are generally classified as either thermal NO_x or fuel-bound NO_x. Thermal NO_x is formed when elemental nitrogen in the combustion air is oxidized at the high temperatures in the primary combustion zone yielding nitrogen oxide (NO) and nitrogen dioxide (NO₂). The rate of formation of thermal NO_x is a function of residence time and free oxygen, and increases exponentially with peak flame temperatures. Fuel-bound NO_x is formed by the oxidation of chemically bound nitrogen in the fuel. The rate of formation of fuel-bound NO_x is primarily a function of fuel bound nitrogen content, but may also be affected by fuel/air mixing. Natural gas has insignificant amounts of chemically bound nitrogen.

The NO_x emissions from Power Boiler No. 26 are small (on the order of 74 lb/hr). Power Boiler No. 26 burns a clean fuel, has a low annual capacity factor and produces relatively small visibility impacts. No add-on emission controls were considered for this unit as any visibility improvement (offered by an

add-on control) to the already small visibility impacts would not be cost-effective and hence would not constitute BART.

Hence, BART for NO_x is the current emissions signature of Power Boiler No. 26, i.e., an emission rate of 0.94 lb/MMBtu.

3.2.3 PM Emission Control

Power Boiler No. 26 currently has no PM emissions control systems. The baseline PM emission rate for Power Boiler No. 26 is very low (0.0018 lb/MMBtu). Moreover, the contribution of PM emissions from Power Boiler No. 26 to visibility impairment is relatively small.

Since Power Boiler No. 26 is a natural gas fired boiler, it has very low emissions of PM (less than 0.15 lb/hr). No add-on PM emission controls were considered for this unit as the small visibility improvement offered by any add-on control would not be cost-effective and hence would not constitute BART.

Hence, BART for PM for Power Boiler No. 26 is the current emissions signature of Power Boiler No. 26 i.e., a PM emission rate of 0.0018 lb/MMBtu.

3.3 No. 3 Recovery Boiler

A recovery boiler is used to recover pulping chemicals, evaporate residual moisture from the black liquor solids, and burn the organic constituents and to produce steam. No. 3 Recovery Boiler is a straight fired unit burning black liquor. No. 2 oil may be burned during start-up and shutdown. No. 3 Recovery Boiler at the Luke Mill is currently equipped with a two level staged combustion air control system with ESPs.

The following BART control scenario was evaluated for the No. 3 Recovery Boiler:

- Control Case - The current (2009-2010 period) emissions signature of the No.3 Recovery Boiler which assumes no change in NO_x, SO₂, and PM₁₀ emissions compared to the baseline levels. The recovery boiler currently has a two-level staged combustion air control system to control NO_x and SO₂ emissions and ESPs installed to control PM emissions. Emission levels and stack parameters corresponding to this emissions scenario are shown in Table 3-1 and Table 3-2, respectively.

3.3.1 SO₂ Emission Controls

In general, black liquor contains a significant amount of sulfur, nominally 3% to 5% by weight of the dissolved solids. SO₂ emissions from recovery boilers occur due to the volatilization and subsequent oxidation of sulfur compounds present in black liquor and the occasional use of auxiliary fuel (in this case No. 2 oil). Unlike conventional steam boilers, the vast majority of sulfur that is present in the liquor is not converted to SO₂. Proper operation of the recovery boiler maximizes the conversion of sulfur compounds in the liquor to the principal constituents of pulping chemicals through capture of these compounds in the combustion zone of the boiler by sodium fume released from the smelt bed. Consequently proper operation of the recovery boiler itself results in inherent control of SO₂ emissions.

The available retrofit technologies for control of SO₂ from Kraft mill Recovery Boilers are:

- Staged Combustion Systems
- Wet Scrubbers

The No. 3 Recovery Boiler is currently equipped with a two-level staged combustion air control system which provides control over the boiler operating parameters that minimize SO₂ emissions.

The only available alternative to proper recovery boiler operation with a staged combustion air system for SO₂ control is the use of wet scrubbing. Dry scrubbing techniques, which seek to remove SO₂ via direct injection of solid lime or limestone directly into the recovery boiler flue gas, are not technically feasible for recovery boilers. The reaction products from dry scrubbing (calcium sulfate and other calcium-based salts) would necessarily need to be collected in the PM control system (ESP), and thereby would contaminate the sodium sulfate (salt cake) that the ESP collects and recycles back to the pulping process.

There are only three recovery boilers in the U.S. that are equipped with wet scrubbers in addition to ESPs. However, none of these scrubbers were installed to achieve SO₂ removal: two of the units were installed for heat recovery reasons, and the third was installed on a unit that is equipped with a direct contact evaporator to prevent liquid droplets from being entrained and discharged to the atmosphere. Furthermore, the inherent SO₂ control provided via proper operation of a recovery boiler results in a much lower SO₂ concentration in recovery boiler flue gas than in the flue gas of emission units to which wet scrubbers are routinely applied (such as fossil fuel-fired steam generating units).

Therefore, BART for SO₂ emissions from No. 3 Recovery Boiler is the currently installed two-level staged combustion air control system with ESPs.

3.3.2 NO_x Emission Controls

NO_x emissions generally result from fuel NO_x and thermal NO_x. However, NO_x formation in recovery boilers is believed to be primarily from fuel NO_x because the temperatures in the combustion zone of the boiler are not high enough for significant thermal NO_x formation. Fuel NO_x emissions from recovery furnaces are typically low due to the low nitrogen content of black liquor solids. In addition, No. 3 Recovery Boiler operates as a staged combustion boiler with independently operating primary, secondary and tertiary air dampers. Total air and the distribution between the air stages can be adjusted to control the Kraft recovery sodium sulfite reactions, to assure complete combustion of organic compounds, and to control TRS, CO and NO_x.

The available retrofit technologies for control of NO_x from combustion sources are generally considered to be:

- Staged Combustion Systems
- SNCR
- SCR
- Low NO_x burners
- Flue Gas Recirculation

Recovery boilers are complex systems, specifically designed for chemical recovery, that can not apply the types of NO_x emission controls used on typical coal, oil, and natural gas fired boilers such as low NO_x burner, flue gas recirculation, selective non-catalytic reduction, and selective catalytic reduction.

Low NO_x burners, which use staged combustion, have not been demonstrated on recovery boilers. Black liquor has a large percentage of water that requires specifically designed black liquor burner guns that provide long droplet trajectories for drying (see the NCASI retrofit control technology assessment in Appendix B).

Flue gas recirculation is a technology used to control thermal NO_x by reducing combustion temperatures. However, NO_x emissions from recovery furnaces are a result of fuel NO_x oxidation. Therefore, flue gas recirculation is not technically feasible for recovery furnaces.

Selective non-catalytic reduction has not been demonstrated on recovery boilers. There are concerns that long term injection of ammonia or urea in a recovery furnace may adversely affect the chemical recovery process. In addition, large variations in gas temperatures due to fluctuating loads and black liquor quality would adversely affect the performance of selective non-catalytic reduction. Ammonia slip and increased plume opacity are also issues.

Selective catalytic reduction is not technically feasible due to high particulate concentrations in the economizer region and catalyst poisoning by alkali metals such as sodium.

In summary, there are no technically-feasible alternatives for control of NO_x emissions from recovery boilers other than the controls that are currently in place. In particular, emission controls which have been demonstrated on conventional steam boilers (including low NO_x burner, flue gas recirculation, selective non-catalytic reduction, and selective catalytic reduction) cannot be applied to or have not been demonstrated to be feasible on a recovery boiler.

Therefore, BART for NO_x emissions from No. 3 Recovery Boiler is the currently installed two-level staged combustion air control system with ESPs.

3.3.3 PM Emission Control

Particulate matter emissions from the No. 3 Recovery Boiler are currently controlled using a three-chamber electrostatic precipitator (ESP1, ESP2 and ESP3).

The available retrofit technologies for control of particulate matter from Kraft mill Recovery Boilers are:

- Electrostatic Precipitators
- Wet Scrubbers
- Fabric Filters

Recovery boilers are designed and operated so that sodium fume released from the smelt bed is present in the combustion chamber in order to capture the SO₂ that is generated as a result of oxidation of the reduced sulfur compounds in black liquor. As a consequence, recovery boilers emit relatively low levels of SO₂ emissions, but have higher levels of uncontrolled PM emissions. Nonetheless, economical operation of the chemical recovery cycle in the Kraft pulping process requires that the vast majority of this uncontrolled PM be captured in a control device and the collected sodium salts (primarily sodium sulfate) be returned to the process.

Electrostatic precipitation is the only type of PM control technology used on modern recovery boilers at Kraft pulp mills. At one time prior to the promulgation of New Source Performance Standards for Kraft pulp mills, recovery boilers utilized venturi scrubbers for PM emissions control. However because ESPs are capable of a greater degree of emissions control at a lower operating cost, venturi scrubbers are no longer utilized.

Fabric filters have been utilized on conventional coal-fired steam generating units and are generally considered to be equivalent to ESPs on these types of sources in terms of PM control efficiency. However, they have not been applied to recovery boilers at Kraft pulp mills and are thus not considered to be an available BART alternative.

Consequently, there are no alternatives that offer a greater degree of PM emissions control than the three-chamber ESP that is currently in use on this unit and hence constitutes BART for the No. 3 Recovery Boiler.

4.0 CALPUFF Modeling Inputs and Procedures

This section provides a summary of the modeling procedures that were used for the refined CALPUFF analysis conducted for the BART units at the Luke Mill.

4.1 Location of Source vs. Relevant Class I Areas

Figure 4-1 shows the location of the Luke Mill relative to nearby Class I areas. There are four Class I areas within 300 km of the facility: Shenandoah National Park (VA), Dolly Sods Wilderness Area (WV), Otter Creek Wilderness Area (WV), and James River Face Wilderness Area (VA). The BART modeling analysis has been conducted for all of these Class I areas in accordance with the referenced Visibility Improvement State and Tribal Association of the Southwest (VISTAS) common BART modeling protocol and FLAG 2008 guidance.

4.2 General Modeling Procedures

Class I modeling was conducted using three years (2001-2003) of CALMET meteorological database. The database was developed for use in BART assessment in VISTAS. VISTAS has developed five sub-regional 4-km CALMET meteorological databases. Class I modeling for the Luke Mill was done using sub-domain #5.

CALMET processing procedures are fully described in the VISTAS common BART modeling protocol, available at http://www.vistas-sesarm.org/documents/BARTModelingProtocol_rev3.2_31Aug06.pdf.

The receptors used for each of the Class I areas are based on the National Park Service database of Class I receptors, available at <http://www.nature.nps.gov/air/maps/Receptors/index.cfm>.

4.3 Model Version

The EPA-approved version of CALPUFF was used to model the emissions and Version 6 of CALPOST was used to process the regional haze impacts with Method 8 (New IMPROVE equation). CALPUFF Version 5.8, Level 070623 and CALPOST Version 6.221, Level 080724 were used.

These programs are available at <http://www.src.com/calpuff/calpuff1.htm>.

4.4 Background Air Quality Data

CALPUFF modeling was conducted with the hourly background ozone data that was developed for VISTAS sub domain #5 and a monthly ambient ammonia background of 0.5 ppb. This ammonia background corresponds to the value listed in the VISTAS BART protocol.

4.5 Light Extinction and Haze Impact Calculations

The FLAG 2008 document (dated June 26, 2008) provides guidance on the recommended new IMPROVE equation application. CALPOST Version 6.221 defines this application as Method 8, Mode 5. The assessment of visibility impacts at the Class I areas used CALPOST Method 8.

The CALPOST postprocessor was used for the calculation of the impact of the modeled source's primary and secondary particulate matter concentrations on light extinction. In the new IMPROVE equation, the total sulfate, nitrate, and organic carbon compound concentrations are each split into two fractions, representing small and large size distributions of those components. New terms, such as sea salt (important for coastal locations), absorption by NO₂ (only used where NO₂ data are available), and site-specific Rayleigh scattering have been added to the equation. The new IMPROVE equation for calculating light extinction is shown below.

$$\begin{aligned}
 b_{\text{ext}} = & 2.2 \times f_S(\text{RH}) \times [\text{Small Sulfate}] + 4.8 \times f_L(\text{RH}) \times [\text{Large Sulfate}] \\
 & + 2.4 \times f_S(\text{RH}) \times [\text{Small Nitrate}] + 5.1 \times f_L(\text{RH}) \times [\text{Large Nitrate}] \\
 & + 2.8 \times [\text{Small Organic Mass}] + 6.1 \times [\text{Large Organic Mass}] \\
 & + 10 \times [\text{Elemental Carbon}] \\
 & + 1 \times [\text{Fine Soil}] \\
 & + 0.6 \times [\text{Coarse Mass}] \\
 & + 1.7 \times f_{\text{SS}}(\text{RH}) \times [\text{Sea Salt}] \\
 & + \text{Rayleigh Scattering (Site Specific)} \\
 & + 0.33 \times [\text{NO}_2 \text{ (ppb)}] \quad \{\text{or as: } 0.1755 \times [\text{NO}_2 \text{ (}\mu\text{g/m}^3\text{)}]\}
 \end{aligned}$$

Where:

[] indicates concentrations in $\mu\text{g/m}^3$

$f_S(\text{RH})$ = Relative humidity adjustment factor for small sulfate and nitrate

$f_L(\text{RH})$ = Relative humidity adjustment factor for large sulfate and nitrate

$f_{\text{SS}}(\text{RH})$ = Relative humidity adjustment factor for sea salt

For Total Sulfate < 20 $\mu\text{g/m}^3$:

$$[\text{Large Sulfate}] = ([\text{Total Sulfate}] / 20 \mu\text{g/m}^3) \times [\text{Total Sulfate}]$$

For Total Sulfate \geq 20 $\mu\text{g/m}^3$:

$$[\text{Large Sulfate}] = [\text{Total Sulfate}]$$

And:

$$[\text{Small Sulfate}] = [\text{Total Sulfate}] - [\text{Large Sulfate}]$$

To calculate large and small nitrate and organic mass, substitute ({Large, Small, Total} {Nitrate, Organic Mass}) for Sulfate.

The FLAG 2008 document provides inputs to the new IMPROVE equation that are based on either the 20% best or annual average natural conditions. AECOM elected to use the more conservative inputs that are based on the 20% best days natural conditions.

Inputs to the CALPOST Method 8 calculations for each Class I area were obtained from the FLAG 2008 document tables referenced below.

Table 4-1 References to the New IMPROVE Equation CALPOST Inputs

Sea salt concentration	FLAG 2008 Table V.1-2
Rayleigh scattering	FLAG 2008 Table V.1-2
Monthly f_L (RH)	FLAG 2008 Table V.1-3
Monthly f_S (RH)	FLAG 2008 Table V.1-4
Monthly f_{SS} (RH)	FLAG 2008 Table V.1-5

Figure 4-1 Location of Class I Areas in Relation to the NewPage Luke Mill



5.0 CALPUFF Modeling and BART Determination Results

This section presents the recommended BART determination and provides a summary of the modeled visibility improvement as a result of applying BART to Power Boiler No. 25, Power Boiler No. 26 and No. 3 Recovery Boiler at the Luke Mill.

5.1 Baseline CALPUFF Modeling Results

CALPUFF modeling results of the baseline emissions at four Class I areas are presented in Table 5-1. Modeling was conducted for all three years of CALMET meteorological data (2001-2003). Emission rates that were used in modeling the baseline emissions are listed in Table 2-1.

For each Class I area and year, Table 5-1 lists the 98th percentile (8th highest day's) delta-deciview. The results indicate that the higher visibility impacts generally occur at Shenandoah National Park and Dolly Sods Wilderness. Higher impacts at these Class I area are due to their proximity to the site and local meteorological conditions.

EPA recommends in its BART Guidelines that the 98th percentile value of the modeling results should be compared to the threshold of 0.5 deciviews to determine if a source contributes to visibility impairment. The Guidelines also recommend using the 98th-percentile statistic for comparing visibility improvements due to BART control options.

The results of the baseline emissions modeling indicate that the cumulative visibility impacts from the Power Boiler Nos. 25 and 26 and No. 3 Recovery Boiler exceed 0.5 deciviews in at least one Class I area (see Table 5-1). Therefore, per 40 CFR Part 51, Appendix Y, Power Boiler No. 25, Power Boiler No. 26 and No. 3 Recovery Boiler at the Luke Mill are presumed to be subject to BART because their emissions may reasonably be anticipated to cause or contribute to visibility impairment at a nearby Class I area.

Table 5-1 Regional Haze Impacts Due to Baseline Emissions

Class I Area	Case	2001				2002				2003				2001-2003 Avg
		days > 0.5 dv Δ B _{ext}	days > 1.0 dv Δ B _{ext}	MAX dv Δ B _{ext}	8 th Highest dv Δ B _{ext}	days > 0.5 dv Δ B _{ext}	days > 1.0 dv Δ B _{ext}	MAX dv Δ B _{ext}	8 th Highest dv Δ B _{ext}	days > 0.5 dv Δ B _{ext}	days > 1.0 dv Δ B _{ext}	MAX dv Δ B _{ext}	8 th Highest dv Δ B _{ext}	
Shenandoah NP	Baseline	149	85	3.90	2.40	110	60	2.96	2.20	110	68	3.27	2.44	2.35
Otter Creek W	Baseline	31	11	2.34	1.32	28	10	2.19	1.12	22	12	2.68	1.22	1.22
Dolly Sods W	Baseline	40	22	3.39	2.11	40	18	3.66	1.27	27	18	3.96	1.70	1.69
James River Face W	Baseline	11	1	1.24	0.65	12	2	1.61	0.64	8	2	1.48	0.55	0.61

5.2 Modeling Results for the BART Control Case

CALPUFF modeling result of control case is presented in Tables 5-2. Modeling was conducted for all three years of CALMET meteorological data (2001-2003) for the four Class I areas to determine the effects of the proposed controls on the three BART-eligible units at the Luke Mill. Emission rates that were used in modeling the BART control case are listed in Tables 3-1. Stack parameters associated with the control case are given in Tables 3-2.

For each Class I area and year, the tables below list the 98th percentile delta-deciview values, number of days above 0.5 and 1.0 delta-deciview due to the BART emission controls.

Class I modeling results show that the 3-year average regional haze impacts are reduced by about 1.57 delta-dv (67% reduction) at Shenandoah, by 0.83 delta-dv (~68% improvement) at Otter Creek, by 1.11 delta-dv at Dolly Sods (~66% improvement) and by 0.47 delta-dv at James River Face (~77% improvement) relative to the baseline case with the future controlled emissions signature of the Power Boiler No. 25, Power Boiler No. 26 and No. 3 Recovery Boiler.

Table 5-2 Regional Haze Impacts Due to the Future Controlled Emissions

Class I Area	Case	2001				2002				2003				2001-2003 Avg
		days > 0.5 dv Δ B _{ext}	days > 1.0 dv Δ B _{ext}	MAX dv Δ B _{ext}	8 th Highest dv Δ B _{ext}	days > 0.5 dv Δ B _{ext}	days > 1.0 dv Δ B _{ext}	MAX dv Δ B _{ext}	8 th Highest dv Δ B _{ext}	days > 0.5 dv Δ B _{ext}	days > 1.0 dv Δ B _{ext}	MAX dv Δ B _{ext}	8 th Highest dv Δ B _{ext}	8 th Highest dv Δ B _{ext}
Shenandoah NP	Future	43	5	1.39	0.89	21	0	0.97	0.69	38	3	1.06	0.76	0.78
Otter Creek W	Future	4	0	0.85	0.34	4	0	0.83	0.34	6	0	0.88	0.48	0.39
Dolly Sods W	Future	10	4	1.18	0.73	7	2	1.31	0.48	9	2	1.29	0.51	0.58
James River Face W	Future	0	0	0.26	0.14	1	0	0.56	0.16	0	0	0.47	0.12	0.14

5.3 BART Results and Discussion

As discussed earlier in this section, visibility improvements resulting from the future controlled emissions level of Power Boiler No. 25 are on the order of 66-77% compared to the baseline. Therefore, we conclude that the recommended BART for Power Boiler No. 25 is the installation of an add-on SO₂ control (either a Spray Dryer Absorber or a Circulating Dry Scrubber), year-round operation of the existing SNCR for NO_x control and multicyclones and baghouse for PM control. Burning natural gas, which inherently has low nitrogen, sulfur and ash content, constitutes BART for Power Boiler No. 26. The currently installed two-level staged combustion air control system with ESPs constitutes BART for the No. 3 Recovery Boiler.

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Appendix A

Particulate Emissions for Pulp and Paper Industry Specific Sources

Particulate Emissions Data for Pulp and Paper Industry Specific Sources

The following tables contain summarized particulate emissions data for sources that are specific to the pulp and paper industry. The source categories addressed in this document are smelt dissolving tanks, lime kilns, and recovery furnaces. Boilers are not addressed since AP-42 emission factors for boiler emissions are well documented and readily available including in NCASI Technical Bulletin No. 884.

Smelt Dissolving Tanks

Data for smelt dissolving tanks were compiled from NCASI Technical Bulletins Nos. 884 and 898. This data set includes test results from the use of a dilution tunnel method which quantifies total PM₁₀ and PM_{2.5} particulate matter. Total PM₁₀ and PM_{2.5} particulate matter are the sum of filterable and condensible PM₁₀ and PM_{2.5} particulate matter. All smelt dissolving tanks in the data set have wet particulate control devices.

The filterable PM numbers are obtained from combining the data set of 36 sources listed in NCASI Technical Bulletin No. 884, Table A15c, and the data set of 6 sources listed in NCASI Technical Bulletin No. 898. The data for "Total PM₁₀" and "Total PM_{2.5}" are from the 8 sources listed in NCASI Technical Bulletin No. 884, Table A15d. All of the CPM data was from the 6 sources listed in NCASI Technical Bulletin No. 898. The CPM data listed in Technical Bulletin No. 884 was not used as that data is an estimate of CPM and not results from EPA Method 202. All of the sulfate data is from the 3 sources tested by NCASI, and listed in Technical Bulletin No. 898.

Table 1. Smelt Tank Data Summary

Parameter	Measurement Method	No. of Sources	Range (lb/ton BLS)	Mean	⁵ Mean Percent of PM
PM	EPA Method 5	42	0.03 - 0.64	0.148	
⁶ Total PM ₁₀	Dilution Tunnel	8	¹ 0.031 - 0.666	² 0.154	⁶ 104
⁶ Total PM _{2.5}	Dilution Tunnel	7	¹ 0.027 - 0.570	² 0.132	⁶ 89
CPM MeCl ₂ Soluble	EPA 202	6	¹ 0.0009 - 0.0192	² 0.0044	3
CPM Water Soluble	EPA 202	6	¹ 0.0039 - 0.0832	² 0.0192	13
CPM	EPA Method 202	6	¹ 0.0048 - 0.1024	² 0.0237	16
Sulfate	IC	3	³ 0.0014 - 0.0297	⁴ 0.0069	% of CPM = 29

¹Range values were determined by applying the mean percent of PM to the range of values for PM. ²Mean values were determined by applying the mean percent of PM to mean value for PM. ³Range values for sulfate were determined by applying the mean percent of CPM to the range of CPM values. ⁴Mean value for sulfate was determined by applying the mean percent of CPM to the mean value for CPM. ⁵Mean percent of PM values are derived from individual data sets. ⁶Values include filterable and condensable PM.

Recovery Furnaces

The recovery furnace data are a compilation of data in NCASI Technical Bulletins Nos. 852, 884, and as yet unpublished NCASI data. All of the recovery furnaces in this data set use electrostatic precipitators (ESP) for particulate control.

The PM data for DCE recovery furnaces is from the 23 sources listed in NCASI Technical Bulletin No. 884, Table A11c. The PM_{10} data for the DCE recovery furnaces is from the 4 DCE sources listed in Technical Bulletin No. 884, Table A11d. The $PM_{2.5}$ data for DCE recovery furnaces is from the 4 DCE sources listed in Technical Bulletin No. 884, Table A11d, plus a further two from as yet unpublished NCASI data. The DCE CPM data is from two sources listed in Technical Bulletins Nos. 852 and 884, and two sources from as yet unpublished NCASI data.

The PM data for the NDCE recovery furnaces is from the 20 sources listed in NCASI Technical Bulletin No. 884, Table A12b. The PM_{10} data for the NDCE recovery furnaces is from the 13 NDCE sources listed in Technical Bulletin No. 884, Table A12c. The $PM_{2.5}$ data for NDCE recovery furnaces is from the 11 DCE sources listed in Technical Bulletin No. 884, Table A12c, plus a further source from as yet unpublished NCASI data. The NDCE CPM data is from 6 sources listed in Technical Bulletin No. 884, and one source from as yet unpublished NCASI data.

Table 2. Recovery Furnace Data Summary

Kraft DCE Recovery Furnace					
Parameter	Measurement Method	No. of Sources	Range (lb/ton BLS)	Mean	⁵ Mean Percent of PM
PM	EPA Method 5	23	0.07 - 2.58	0.74	
PM ₁₀	EPA CTM-040	4	¹ 0.05 - 1.88	² 0.54	73
PM _{2.5}	EPA CTM-040	6	¹ 0.04 - 1.44	² 0.41	56
CPM MeCl ₂ Soluble	EPA 202	4	¹ 0.014 - 0.516	² 0.148	20
CPM Water Soluble	EPA 202	4	¹ 0.13 - 4.75	² 1.36	184
CPM	EPA Method 202	4	¹ 0.14 - 5.29	² 1.52	205
Sulfate	IC	3	³ 0.05 - 1.85	⁴ 0.53	% of CPM = 35
Kraft NDCE Recovery Furnace					
Parameter	Measurement Method	No. of Sources	Range (lb/ton BLS)	Mean	⁵ Mean Percent of PM
PM	EPA Method 5	20	0.02 - 3.50	0.65	
PM ₁₀	EPA CTM-040	13	¹ 0.01 - 2.35	² 0.44	67
PM _{2.5}	EPA CTM-040	11	¹ 0.01 - 1.82	² 0.34	52
CPM MeCl ₂ Soluble	EPA 202	3	¹ 0.003 - 0.560	² 0.104	16
CPM Water Soluble	EPA 202	3	¹ 0.016 - 2.84	² 0.53	81
CPM	EPA Method 202	7	¹ 0.02 - 3.40	² 0.63	97
Sulfate	IC	2	³ 0.007 - 1.16	⁴ 0.21	% of CPM = 34

¹Range values were determined by applying the mean percent of PM to the range of values for PM. ²Mean values were determined by applying the mean percent of PM to the mean value for PM. ³Range values for sulfate were determined by applying the mean percent of CPM to the range of CPM values. ⁴Mean value for sulfate was determined by applying the mean percent of CPM to the mean value for CPM. ⁵Mean percent of PM values are derived from individual data sets.

Lime Kilns

The lime kiln data are a compilation of data from NCASI Technical Bulletins Nos. 852, 884, and 898. The emissions data are separated by control device type. The majority of lime kilns in this data set use wet control devices for particulate control. Two of the lime kilns in this data set use an ESP for particulate control, followed by a wet scrubber for SO₂ control. The remainder use an ESP for particulate control.

The PM data for lime kilns using wet control devices is from 30 sources listed in NCASI Technical Bulletin No. 884, Table A13c. The PM₁₀ and PM_{2.5} data for lime kilns using wet control devices is from NCASI Technical Bulletin No. 884, Table A13d. The CPM and sulfate data for lime kilns using wet control devices is from Technical Bulletin No. 898.

All of the PM, CPM, and sulfate data for lime kilns using an ESP followed by a wet control device is from two sources listed in NCASI Technical Bulletin No. 898.

The PM data for lime kilns using an ESP alone are from the 7 sources listed in NCASI Technical Bulletin No. 884, Table A13c. The PM₁₀ and PM_{2.5} data are from the 6 sources listed in Technical Bulletin No. 884, Table A13d. The CPM and sulfate data are from 3 sources listed NCASI Technical Bulletin Nos. 852 and 884.

Table 3. Lime Kiln Data Summary

Lime Kilns with Wet Particulate Control Devices					
Parameter	Measurement Method	No. of Sources	Range (gr/dscf) @10% O ₂	Mean	⁵ Mean Percent of PM
PM	EPA Method 5	30	0.014 - 0.346	0.0995	
⁶ Total PM ₁₀	Dilution Tunnel	6	¹ 0.014 - 0.349	² 0.100	101
⁶ Total PM _{2.5}	Dilution Tunnel	7	¹ 0.012 - 0.304	² 0.088	88
CPM MeCl ₂ Soluble	EPA Method 202	3	¹ 4.2E-5 - 0.0010	² 0.0003	0.3
CPM Water Soluble	EPA Method 202	3	¹ 0.0008 - 0.0208	² 0.0060	6
CPM	EPA Method 202	3	¹ 0.0009 - 0.0218	² 0.0063	6.3
Sulfate	IC	2	³ 0.0002 - 0.0046	⁴ 0.0013	% of CPM = 21
*These data are the result of dilution tunnel testing, therefore the PM ₁₀ and PM _{2.5} values reflect the sum of filterable and condensable PM ₁₀ and PM _{2.5} particulate.					
Lime Kilns with a Dry ESP for Particulate Control Followed by a Wet Scrubber					
Parameter	Measurement Method	No. of Sources	Range (gr/dscf) @10% O ₂	Mean	⁵ Mean Percent of PM
PM	EPA Method 5	2	0.003 - 0.004	0.004	
PM ₁₀			No Data	No Data	
PM _{2.5}			No Data	No Data	
CPM MeCl ₂ Soluble	EPA Method 202	2	0.0004 - 0.0081	0.0042	140
CPM Water Soluble	EPA Method 202	2	0.0038 - 0.0054	0.0046	131
CPM	EPA Method 202	2	0.006 - 0.012	0.009	271
Sulfate	IC	1	0.002	0.002	% of CPM = 34
Lime Kilns with a Dry ESP for Particulate Control					
Parameter	Measurement Method	No. of Sources	Range (gr/dscf) @10% O ₂	Mean	⁵ Mean Percent of PM
PM	EPA Method 5	7	0.002 - 0.033	0.010	
PM ₁₀	EPA CTM-040	6	¹ 0.001 - 0.211	² 0.006	64
PM _{2.5}	EPA CTM-040	6	¹ 0.0005 - 0.0079	² 0.0024	24
CPM MeCl ₂ Soluble	EPA Method 202	3	¹ 0.0013 - 0.0208	² 0.0063	63
CPM Water Soluble	EPA Method 202	3	¹ 0.003 - 0.045	² 0.014	137
CPM	EPA Method 202	3	¹ 0.004 - 0.066	² 0.020	200
Sulfate	IC	3	³ 0.0035 - 0.0581	⁴ 0.0176	% of CPM = 88

¹Range values were determined by applying the mean percent of PM to the range of values for PM. ²Mean values were determined by applying the mean percent of PM to the mean value for PM. ³Range values for sulfate were determined by applying the mean percent of CPM to the range of CPM values. ⁴Mean value for sulfate was determined by applying the mean percent of CPM to the mean value for CPM. ⁵Mean percent of PM values are derived from individual data sets. ⁶Values include filterable and condensable PM.

Appendix B

NCASI – Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_x, SO₂ and PM Emissions



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June 9, 2006

TO: Corporate Correspondents -- CC 06-014
Regional Managers

FROM: Ronald A. Yeske *Ray*

SUBJECT: Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_x, SO₂ and PM Emissions

The attached document "Retrofit Control Technology Assessment for NO_x, SO₂ and PM Emissions from Kraft Pulp and Paper Mill Unit Operations" was prepared to assist NCASI member company personnel involved in conducting Best Available Retrofit Technology (BART) site-specific engineering analyses. It deals with the three main pollutants of concern for BART analyses, namely NO_x, SO₂ and particulate matter (PM). Potentially available control technologies for these three pollutants for kraft recovery furnaces, lime kilns and boilers burning wood, coal, gas, or oil are discussed. Also, control technologies for PM emissions from lime slakers and smelt dissolving tanks are briefly reviewed.

Sources subject to BART analyses were generally built in the 1962 to 1977 time frame. Thus, application of any control technologies to these sources will involve retrofits. Even though a given technology may have been installed on newer more modern units, or may be theoretically applicable, retrofitting the technology to an older existing unit requires consideration of unit-specific and location-specific factors. In many situations, these factors would eliminate one or more control technologies from consideration due to technical infeasibility or excessive costs. As noted throughout this document, site-specific factors will play a critical role in BART analyses.

This document does not directly address the cost-effectiveness (\$/ton of pollutant removed) of retrofit control measures. Site-specific information, including capital costs, operating and maintenance costs, and annual capacity factors, must be considered in assessing the cost-effectiveness of a given control technology to a particular emission source. Not surprisingly, the ranges in costs and potential emission reductions are expected to be very large.

For more information on this document, please contact Dr. Arun V. Someshwar, Principal Research Engineer, at the Southern Regional Center office, phone (352) 331-1745, ext 226; email asomeshwar@ncasi.org.

Attachment

Retrofit Control Technology Assessment for NO_x, SO₂ and PM Emissions From Kraft Pulp and Paper Mill Unit Operations

by Arun V. Someshwar, Ph. D., NCASI

1.0 Introduction

This document summarizes the general applicability of currently available emission control technologies for NO_x, SO₂ and particulate matter (PM) to various pulp and paper mill sources. The three main unit operations in a kraft pulp mill that emit NO_x, SO₂ and PM are kraft recovery furnaces, lime kilns and boilers. Boilers can be of the type which burn wood residues alone, wood in combination with coal, gas or oil, or only fossil fuels. Particulate emissions can also result from lime slakers and smelt dissolving tanks. Other pulp and paper mill sources for PM are generally quite insignificant.

The origin and nature of the three pollutants in each relevant pulp mill unit operation is first discussed. Such discussion should be useful in understanding why some control technologies, while being suitable candidates for certain unit operations in other industries, may not be suitable in the pulp and paper industry. It is hoped this document will be useful in the context of a Best Available Retrofit Technology (BART) site-specific engineering analysis. However, it must be clearly noted that for any retrofit technology, site-specific considerations for a given emission source may disqualify a particular control technology from consideration, even though it might theoretically be feasible or may even have been installed elsewhere on a new, modern unit or a greenfield operation.

Cost and emission reduction estimates are specifically not covered in this document. However, it is instructive to consider that a wide range in costs and potential emission reductions are expected due to the fact that site-specific factors play a critical role in determining how cost-effective various technologies will be in practice. Many facilities are space-limited, have controls already in place, or have older combustion equipment that cannot be retrofit to reach required conditions, making installation of certain technologies problematic or very expensive.

2.0 Kraft Recovery Furnaces

2.1 NO_x Control

Compared to coal- or residual oil-fired boilers of similar capacity, NO_x emissions from kraft recovery furnaces are generally quite low, typically in the 60 to 130 ppm range. These low NO_x emissions are due to several factors inherent to kraft recovery furnace operations which include (a) low nitrogen concentrations in most "as-fired" black liquor solids (generally <0.2%), (b) recovery furnace NO_x formation resulting predominantly from "fuel NO_x" mechanisms (insufficient temperatures for "thermal NO_x" formation), (c) the highly staged combustion design of recovery furnaces, and (d) the existence of sodium fumes that might participate in "in-furnace" NO_x reduction or removal.

Researchers have concluded that nearly two-thirds to three-fourths of the liquor N is released during pyrolysis or devolatilization, partly as NH₃ and partly as N₂, the rest remaining with the smelt product most likely as a reduced N species. The ammonia released from the black liquor during pyrolysis partly oxidizes to NO and partly reduces to N₂. A review of the theoretical kinetics governing the reactions between NH₃, NO, and O₂ suggests that, in the presence of

excess O₂, a decrease in temperature decreases the degree of oxidation of NH₃ to NO, thus implying that fuel NO_x generation during black liquor combustion is more temperature-dependent than previously thought. However, a reduction in furnace temperatures, particularly in the lower furnace, is generally expected to result in a sharp increase in SO₂ emissions from the furnace. Most of the NO is formed by oxidation of the NH₃ volatilized during pyrolysis of the liquor droplets. Very little NO is formed from the N in the char bed. In certain instances, where the liquor droplet dries completely before reaching the char bed, additional NO can be formed during "in-flight" char combustion of the liquor droplet. The use of liquor sprays resulting in larger droplet sizes avoids the problem of additional NO contribution from char burning.

Some have observed that NO_x emissions increased when firing liquors with increasing liquor solids contents. However, this may have had less to do with thermal NO_x or an "in-furnace" capability of alkali fume to capture NO_x as suggested by some, but more to do with a possible effect on increased conversion of ammonia to NO within the furnace due to an increase in lower furnace temperatures resulting from firing higher solids liquors.

2.1.1 Low NO_x Burners

The use of low-NO_x burners (LNB) for black liquor combustion has not been demonstrated. Unlike fossil fuels, black liquor has a large quantity of water and the drying, pyrolysis, and char burning of liquor droplets occurs over a long flight trajectory from the liquor guns to the char bed, thus making unavailable the benefits of staged combustion inherent in LNB designs.

LNBs could however be applied to oil guns or gas burners in recovery furnaces that are used to supply supplemental heat or for start-up/shut down purposes. However, for most recovery units, the use of auxiliary fuel is very limited; in such cases the benefit from conversion to LNB would be marginal.

2.1.2 Staged Combustion

Recent research has concluded that to the extent "staged combustion" is allowed to take place in the upper furnace during oxidation of the volatilized NH₃ to NO, such oxidation can be minimized. Limited short-term experience after installing "quaternary" air ports in two U.S. furnaces showed that a 20 to 40% reduction in baseline NO_x levels is feasible using such air staging. However, to make it feasible to install a quaternary air system a recovery furnace typically needs to be fairly large in size. Thus this option would not be feasible for most BART-eligible recovery furnaces, since units built in the 1962 to 1977 time period were considerably smaller than those installed in subsequent years.

2.1.3 Flue Gas Recirculation (FGR)

Flue gas recirculation (FGR) is also not a viable option for kraft recovery furnaces. In FGR, a portion of the uncontrolled flue gases is routed back to the combustion zone, primarily with the intention of reducing thermal NO_x. Thermal NO_x is, however, not a concern in recovery furnaces, as discussed earlier. FGR would add additional gas volume in the furnace, increasing velocities and potentially causing more liquor carryover, which would result in increased fouling of the recovery furnace tubes.

2.1.4 Oxygen Trim + Water Injection

Oxygen-trim + water injection, a NO_x control technology generally utilized in natural gas-fired boilers, would not be relevant to kraft recovery furnaces since (1) any injection of water into the furnace would lead to an unacceptable explosive condition and (2) the oxygen trim technique would have marginal effect due to the already existing highly staged combustion air configuration in recovery furnaces.

2.1.5 Selective Non-Catalytic Reduction (SNCR)

At the current time, there is no published information on the extended use of SNCR on an operating kraft recovery furnace. Short-term tests with the SNCR technology have been reported in the literature on two furnaces in Japan and one in Sweden. There are a number of critical, unresolved issues surrounding the use of urea or ammonia injection in a kraft recovery furnace for NO_x control over a long-term basis. A kraft recovery furnace is the most expensive unit operation in a pulp mill since its primary purpose is to recover chemicals from spent pulping liquors in a safe and reliable manner. Although steam is generated from liquor combustion, certain chemical recovery steps have to be accomplished inside the furnace. It is not known whether the injection of NO_x-reducing chemicals into the furnace would have deleterious effects on the kraft liquor recovery cycle on a long-term basis. Long-term tests would need to be carried out to address this important issue. In addition, there are several other factors that make the use of SNCR in a kraft recovery furnace problematic such as (1) the impact of large variations in flue gas temperatures at the superheater entrance due to fluctuating load and liquor quality, (2) limited residence times for the NO_x-NH₃ reactions available in smaller furnaces, (3) impact on fireside deposit buildup due to reduced chloride purging from long-term NH₃/urea use and resulting impact on tube corrosion and fouling, and (4) potential for significant NH₃ slip and plume opacity problems due to NH₄Cl emissions. Unless these concerns are satisfactorily resolved, the use of SNCR in a kraft recovery furnace should not be considered as a feasible technology.

2.1.6 Selective Catalytic Reduction (SCR)

The use of SCR on a kraft recovery furnace has never been demonstrated, even on a short-term basis. The impact of high particulate matter concentrations in the economizer region and fine dust particles on catalyst effectiveness is a major impediment to the application of this technology ahead of PM control, as is catalyst poisoning by soluble alkali metals in the gas stream. For SCR installation after an ESP, the gas stream would be too cold for effective reaction with the NO_x. A substantial energy penalty would have to be incurred to reheat the flue gas prior to the SCR section which would be a major drawback.

2.1.7 Summary

In summary, optimization of the staged combustion principle within large, existing kraft recovery furnaces to achieve lower NO_x emissions might be the only technologically feasible option at the present time for NO_x reduction. However, the effect of such air staging on emissions of other pollutants, chiefly SO₂, CO, and TRS, and other furnace operational characteristics needs to be examined with longer-term data on U.S. furnaces. Ultimately, the liquor nitrogen content, which is dependent on the types of wood pulped, is the dominant factor affecting the level of NO_x emissions from black liquor combustion in a recovery furnace. Unfortunately, this factor is beyond the control of pulp mill operators.

2.2 SO₂ Control

Black liquor contains a significant amount of sulfur, nominally 3 to 5% by weight of the dissolved solids. While the vast majority of this sulfur leaves the furnace in the smelt product, a small fraction (generally under 1%) can escape in gaseous or particulate form. Average SO₂ concentrations in stack gases can range from nearly 0 to 500 ppm, although most furnaces currently operate with <100 ppm SO₂ in stack emissions. Factors which influence SO₂ levels are liquor sulfidity, liquor solids content, stack oxygen content, furnace load, auxiliary fuel use, and furnace design. However, none of these factors has exhibited a consistent relationship with SO₂ emissions. At the present time, it is generally understood that conditions involving liquor quality (such as high Btu, high solids liquors) and liquor firing patterns and conditions related to furnace operations (air distribution, auxiliary fuel, etc.) that lead to maximizing temperatures in the lower furnace result in minimizing SO₂ emissions from kraft recovery furnaces.

There is no experience in the pulp and paper industry with the use of dedicated, add-on flue gas desulfurization technologies on kraft recovery furnaces. Although there are a few scrubbers on U.S. kraft recovery furnaces, none of these were installed for SO₂ removal. Only one U.S. recovery furnace does not use an ESP for particulate control; this unit has venturi scrubbers instead. All of the other scrubbers follow an ESP. Two were installed for heat recovery reasons, although some SO₂ scrubbing may also be occurring especially when caustic is added to the scrubbing solution. One scrubber following an ESP was installed with the main purpose of achieving incremental particulate matter removal. Another scrubber following an ESP was installed on a furnace with a direct contact evaporator to control black liquor droplets being entrained in the cascade and traveling all the way throughout the ESP and out the stack. Even if these scrubbers had been installed to reduce SO₂ emissions, the removal costs in terms of dollars per ton of SO₂ removed would be large due to high gas flows and site-specific retrofit considerations. Significant capital would be required for the large gas handling equipment and additional induced fan capacity needed to overcome the increased pressure drop across the scrubber.

2.3 Particulate Matter Control

Recovery furnaces are designed and operated in a manner so as to ensure the presence of high levels of sodium fumes in order to capture the sulfur dioxide produced as a result of oxidation of reduced sulfur compounds. Consequently, uncontrolled recovery furnace flue gases contain high levels of particulate matter. The uncontrolled particulate matter load from recovery furnaces is highly variable and has been reported to range from 100 to 250 lb/ODTP (oven dry ton pulp) for direct contact evaporator (DCE) furnaces and 200 to 450 lb/ODTP for non-direct contact evaporator (NDCE) furnaces. The lower particulate loading from DCE furnaces is due to the capture of some particulate matter in the direct contact evaporator. ESPs built for NDCE furnaces are designed to compensate for the higher particulate loading.

Particulates generated in the recovery furnace are comprised mainly of sodium sulfate, with lesser amounts of sodium carbonate and sodium chloride. Similar potassium compounds are also generated, but in much lower amounts. Trace amounts of other metal compounds, e.g. magnesium, calcium, and zinc, can be present. A significant portion of the particulate material is sub-micron in size, which makes removal with additional add-on control devices more difficult.

Increasing liquor firing density (ton/day/ft²) increases recovery furnace particulate loading. Other factors such as bed and furnace temperature, liquor solids, liquor composition, and air distribution also affect uncontrolled particulate emissions from recovery furnaces.

ESPs are the device of choice for controlling PM emissions from kraft recovery furnaces. The use of larger ESps is expected to result in better overall PM capture efficiencies. However, this option is expected to be quite cost ineffective based on the high, site-specific, retrofit costs incurred. Moreover, with the implementation of MACT II limitations in 2004, most recovery furnaces are operating at or below NSPS levels (NCASI Corporate Correspondents Memo 01-01). Any additional benefit would thus be marginal.

3.0 Kraft Lime Kilns

3.1 NO_x Control

NO_x emissions from lime kilns result mainly from fossil fuel burning (natural gas and fuel oil). A recent NCASI study involving NO_x testing at 15 lime kilns verified that "thermal" NO_x was the sole mechanism operative in gas-fired kilns, while the "fuel" NO_x mechanism was mostly operative in oil-fired kilns. Gas-fired kiln NO_x emissions appeared to be strongly dependent on the dry-end lime temperature. Oxygen availability in the combustion zone was determined to be the key factor in oil-fired kilns. NO_x emissions for gas-fired kilns also exhibited high short-term variability, unlike for oil-fired kilns. Analysis of long-term daily average data from two lime kilns showed no difference in NO_x emissions between days with and without LVHC NCG burning. An earlier NCASI study had shown that when stripper off-gases (SOGs) containing ammonia were burned in lime kilns, a small fraction of the ammonia, up to 23%, converts to NO_x.

A BACT analysis conducted for a new lime kiln in 1997 concluded that the use of low NO_x burners in lime kilns was technically infeasible due to complexities resulting in poor efficiency, increased energy usage, and decreased calcining capacity of the lime kiln. The concept of 'low NO_x burners' is considered a misnomer in the rotary kiln industry. In boiler burners where the combustion air can be staged, 'low NO_x' could be a genuine option. However, in rotary kilns it is not possible to stage the mixing in the same way. There has to be sufficient primary (burner) air to provide control in flame shaping although this can be limited to minimize NO_x to some extent. Effectively, the NO_x can be reduced to some extent by 'de-tuning' the burner from optimized combustion. However, the result is an energy penalty by way of a higher heat input per ton product and higher feed-end temperatures.

Post-combustion flue gas NO_x control using SCNR or SCR is not feasible due to the configuration of the kraft lime kiln. The necessary temperature window of 1500°F to 2000°F for reagent injection in the SNCR process is unavailable in a kraft lime kiln. The very high PM load prior to control would make SCR infeasible in advance of the controls and the requisite temperature window of between 550°F and 750°F for applying SCR after a PM control device is unavailable for a lime kiln, even for one equipped with an ESP.

Thus, NO_x control in newer lime kilns may be achieved mainly by minimizing the hot end temperatures in gas-fired kilns and by reducing the available oxygen in the combustion zone in oil-fired kilns, both combustion related modifications. However, these modifications may be difficult to achieve in certain existing kilns due to their inherent design. For example, in order to complete the calcining reactions in kilns with short residence times, it is more difficult to control hot end temperatures in shorter kilns than in longer ones.

3.2 SO₂ Control

Sulfur dioxide is formed in lime kilns when fuel oil or petroleum coke is burned as primary fuel. SO₂ will also be formed if non-condensable gases (NCGs) or stripper off-gases (SOGs) containing sulfur are burned in the kiln. Lime muds also contain a small amount of sulfur, which when oxidized, would form SO₂. Median sulfur content of concentrated NCGs and SOGs have been reported as 1.1 and 4.2 lb/ADTP (air dried ton pulp), respectively. Median sulfur contents of 7 lime muds have been reported at 0.2%, which translates to about 1.8 lb S/ADTP. Thus, fossil fuels such as fuel oil, kraft mill NCG/SOGs, and soluble sulfides in lime mud can contribute a significant amount of sulfur to the inputs of a lime kiln. Nevertheless, the regenerated quicklime in the kiln acts as an excellent in-situ scrubbing agent, and venturi scrubbers following the kiln can further augment this SO₂ removal process since the scrubbing solution becomes alkaline from the captured lime dust. Consequently, even though the potential for SO₂ formation in a kiln that burns sulfur-containing fuels with or without NCGs/SOGs is high, most lime kilns emit very low levels of SO₂ (~50 ppm). Some kilns do, however, occasionally emit higher levels of SO₂ (50 to 200 ppm). Not much is known about why this happens.

Emission test data show that SO₂ concentrations do not appear to be related to either the fuel type (oil, gas) or the presence or absence of concentrated NCG or SOG burning in the kiln. A preliminary sulfur input-output balance carried out on 25 kilns with wet scrubbers and 7 kilns with electrostatic precipitators (ESPs), with sulfur inputs from fuel oil, NCGs and SOGs, or just lime mud, showed over 95% of the SO₂ generated from the oil, NCG/SOGs, or lime mud was captured within the kiln. For kilns with wet scrubbers (majority) that have high SO₂ emissions, alkali addition to the scrubbing fluid could further reduce the SO₂ emissions.

3.3 Particulate Matter Control

While passing through the kiln, the combustion gases pick up a good deal of particulate matter both from lime mud dust formation and from alkali vaporization. This PM must be removed before the gases exit to the atmosphere. Mechanical devices such as dust chambers or cyclones are generally used to remove larger particles, which are mainly calcium-containing. A wet scrubber or electrostatic precipitator follows for removal of smaller particulates, which are mainly sodium sulfate and sodium carbonate and have aerodynamic diameters less than 10 μ m.

Kraft lime kiln PM emissions are typically controlled by venturi-type wet scrubbers. Scrubbers with increasingly better PM removal efficiencies, such as the Ducon Dynamic Wet Scrubber, have been installed up until the late 1980s. However, most of the PM control installations on lime kilns since about 1990 have been ESPs. Replacing a wet scrubber with an ESP will most likely reduce PM emissions, but may increase emissions of SO₂. The wet scrubber acts as an additional alkaline SO₂ scrubber since it captures alkaline PM leaving the kiln. Just as for recovery furnaces, with the implementation of MACT II limitations in 2004, most lime kilns are operating at or below NSPS levels. Any additional benefit would thus be marginal.

4.0 Boilers

The majority of pulp and paper industry boilers are combination boilers, in that they are designed to burn more than one fuel. Thus, it should be noted that while a particular technology may be beneficial for a particular pollutant, the same technology may not address the control of another pollutant. For example, a wood-fired boiler with a wet scrubber for PM control may obtain better PM control with an ESP. However, if the boiler also fires some sulfur-containing fuel (as is often the case), the SO₂ removal capability of the wet scrubber will be sacrificed by the installation of an ESP.

4.1 Natural Gas-Fired Boilers

Gas-fired boilers are usually not equipped with particulate collectors. SO₂ emissions depend on the sulfur content of the gas, which is typically negligible. NO_x emissions are dependent on the combustion temperature and the rate of cooling of the combustion products. There are several combustion modification techniques available to reduce the amount of NO_x formed in natural gas-fired boilers and turbines. The two most prevalent ones are flue gas recirculation (FGR) and low-NO_x burners. FGR reduces formation of thermal NO_x by reducing peak temperatures and limiting availability of oxygen. Low-NO_x burners reduce formation of thermal NO_x by delayed combustion (staging) resulting in a cooler flame. In conjunction with FGR, the burners can achieve NO_x emission reductions of 60 to 90%. Other techniques include staged combustion and gas reburning. In general, these techniques have been incorporated in newer boilers and thus their NO_x emissions are lower than those of older units.

There are also add-on control technologies that can reduce NO_x emissions from gas-fired boilers such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). However, since most of the pulp and paper industry gas-fired boilers are of the package boiler type, cost considerations typically make the use of such technologies cost ineffective. Further, both the SNCR and SCR technologies have not been proven to apply to industrial boilers with frequent swing loads.

4.2 Fuel Oil-Fired Boilers

For fuel oil-fired boilers, criteria pollutants can be controlled by fuel substitution/alteration, combustion modification and post-combustion control. Fuel substitution reduces SO₂ and NO_x and involves burning an oil with lower S or N content, respectively. Particulate emissions are lower when burning lower sulfur content oils, especially distillate oil.

4.2.1 NO_x Control

For boilers burning residual oil, fuel NO_x is the dominant mechanism for NO_x formation and thus the most common combustion modification technique is to suppress combustion air levels below the theoretical amount required for complete combustion. There are several combustion modification techniques available to reduce the amount of NO_x formed in fuel oil-fired boilers, including low excess air, burners out of service, biased-burner firing, flue gas recirculation, overfire air, and low-NO_x burners. NO_x reductions that could range between 5 and 60% from uncontrolled systems may be expected from using these techniques.

Post-combustion controls include SNCR and SCR. NO_x reductions from 25 to 0% and from 75 to 85% may be expected from use of SNCR and SCR systems on oil-fired boilers, respectively. However, just as for gas-fired boilers, most of the pulp and paper industry oil-fired boilers are of the package boiler type, and cost considerations typically make the use of such technologies cost ineffective. Furthermore, both the SNCR and SCR technologies have not been proven to apply to industrial boilers with frequent swing loads.

4.2.2 SO₂ Control

SO₂ emissions are controlled by a number of commercialized post-combustion flue gas desulfurization (FGD) processes which use an alkaline reagent to absorb SO₂ in the flue gas and produce a sodium or calcium sulfate compound. The FGD technologies may be wet, semi-dry or dry depending on the state of the reagent as it leaves the absorber vessel.

4.2.3 Particulate Matter Control

Due to the extremely low level of PM emissions, most residual oil-fired boilers do not have particulate matter controls. A few boilers are, however, equipped with mechanical collectors or ESPs.

4.3 Coal-Fired Boilers

4.3.1 NO_x Control

NO_x emissions from coal-fired boilers can be controlled by a) combustion controls and b) post-combustion controls. Combustion controls involve a) reducing peak temperatures in the combustion zone, b) reducing gas residence time in the high-temperature zone, and c) air or fuel staging by operating at an off-stoichiometric ratio by using a rich fuel-air ratio in the primary flame zone and lower overall excess air conditions. The use of combustion controls depends on the type of boiler and the method of coal firing. Low-NO_x burners and overfire air (OFA) have been successfully applied to tangential- and wall-fired units, whereas reburning is the only current option for cyclone boilers. For large base-loaded coal-fired boilers, the most developed and widely applied post-combustion NO_x control technology is SCR. Catalyst deactivation and residual NH₃ slip are the two key operating considerations in an SCR system. There is only limited experience with the use of SNCR systems on industrial coal-fired boilers. NO_x reductions from 30-70% and from 60-90% may be expected from use of SNCR and SCR systems on base-loaded coal-fired boilers, respectively. SNCR has a narrow temperature window in which it is effective, in the 1500 to 1900°F range, and SCR has a similar, but lower temperature window of 550 to 750°F. When applied to industrial boilers, neither the SNCR nor the SCR technologies have been proven to yield the same high NO_x removal efficiencies expected when the boilers operate at base loads as when they operate with frequent swing loads. The inability to maintain good control within the required temperature window during swing loads is most likely responsible for this reduction. Most coal-fired boilers in the pulp and paper industry operate in the swing load mode, a function of supplying steam as required to the various components of the process.

4.3.2 SO₂ Control

Just as in fuel oil combustion, criteria pollutants can be controlled by fuel substitution/alteration, combustion modification and post-combustion control. SO₂ reductions can be achieved by burning a coal with lower S content. SO₂ emissions can be controlled by a number of commercialized post-combustion flue gas desulfurization (FGD) processes which use an alkaline reagent to absorb SO₂ in the flue gas and produce a sodium or calcium sulfate compound. The FGD technologies may be wet, semi-dry or dry depending on the state of the reagent as it leaves the absorber vessel. The pulp and paper industry has limited experience with operating FGD systems on coal- or oil-fired boilers. Retrofit considerations include space restraints in many facilities.

4.3.3 Particulate Matter Control

Particulate emissions from coal-fired boilers are controlled by using a) ESPs, b) fabric filters (FF) or c) venturi scrubbers. Multi-cyclones are generally used as precleaners upstream of more efficient ESPs or FFs. The key operating parameters that influence ESP performance include fly ash mass loading, particle size distribution, fly ash resistivity (which is related to coal sulfur content), and precipitator voltage and current. Data for ESPs applied to coal-fired boilers show

fractional collection efficiencies greater than 99% for fine ($<0.1\ \mu\text{m}$) and coarse particles ($>10\ \mu\text{m}$) and a reduction in collection efficiency for particles between 0.1 and $10\ \mu\text{m}$. Operational parameters that affect fabric filter collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, cleaning method, and cleaning intensity. Collection efficiencies of fabric filters can be as high as 99.9%. Scrubber collection efficiency depends on particle size distribution, gas side pressure drop through the scrubber, and water (or scrubbing liquor) pressure, and can range from 90 to 95% for a $2\ \mu\text{m}$ particle.

4.4 Wood-Fired Boiler Emissions

4.4.1 NO_x Control

Most large wood-fired boilers used in the pulp and paper industry are of the spreader stoker design. NO_x control technologies effective for use on gas and oil burners are not applicable to spreader-stoker design boilers. Furthermore, these boilers are often operated handling swing loads, which makes add-on NO_x controls difficult to implement. Spreader stoker boilers inherently practice staged combustion, which lowers NO_x emissions, but within limits.

Fuel NO_x is the dominant NO_x formation mechanism operative during wood combustion. Fuel NO_x is most efficiently controlled by staged combustion. Overfire air ports inherent to most spreader-stoker boilers provide for staged combustion. The underfire and overfire air are balanced in most wood-fired spreader stokers to control NO_x.

As with other fuels, potential post-combustion controls include SNCR and SCR. SNCR has been applied to a few base-loaded wood-fired boilers, mainly in the electric generating industry. However, its long-term efficacy on wood-fired boilers with changing loads has not been demonstrated. Experience in the pulp and paper industry to date has shown it has been used on occasions for polishing, to get perhaps 10-20% NO_x reduction during periods of air quality problems. The problem with control of the required temperature window is an inherent difficulty with use of SNCR for load-following boilers, whether wood or fossil fuel. Inadequate reagent dispersion in the region of reagent injection in wood-fired boilers is also a factor mitigating against the use of SNCR technology. At least one pulp mill wood-fired boiler met with significant problems and had to abandon their SNCR system. Significant ammonia slip, caused by inefficient dispersion of the reagent within the boiler, was to blame.

The use of SCR on wood-fired boilers operating in the forest products industry has also never been successfully demonstrated for spreader stoker boilers, and would face the same inherent problem of requiring it to be post PM-control to protect the catalyst, and achieving and maintaining the required temperature window for effective NO_x control.

4.4.2 Particulate Matter Control

Particulate matter is the air pollutant of primary concern in wood-fired boilers. As for coal-fired boilers, the most common devices used to control particulate emissions from wood-fired boilers are wet scrubbers and electrostatic precipitators (ESPs). Fabric filters (FF) and the electrified gravel bed filter (EGF) have been used on a few units. Wet scrubbers are widely used, operating at gas pressure drops ranging from 6 to 25" H₂O. Liquid to gas ratios in the venturi system typically range from 8 to 10 gal H₂O/1000 acfm saturated. Solids buildup in the recirculation loop rarely is allowed to exceed 5% by weight. High carbon ash resulting from wood combustion is more difficult to remove with an ESP due to its high conductivity/low resistivity. Thus, specific collection areas (ratio of ESP plate area to gas flow volume through the ESP) for ESPs

on wood-fired boilers are greater than for those for coal-fired boilers, ranging from about 300 to 500 ft²/1000 acfm. Power requirements range from 150 to about 400 watts per acfm. To address fire concerns, ESPs on wood-fired boilers are sometimes operated in the wet mode, where the collection plates and internal parts are wetted continuously with water. A pre-quench is generally used to saturate the gas stream. Fabric filters are rarely used on wood-fired boilers due to concerns about bag flammability. Fabric filters have been successfully used where bark from logs stored in salt water is burned and the salt reduces the fire hazard. In this situation, the fabric filter is effective in removing the very small salt particulates exiting the boiler. Gravel-bed filters have a slowly moving bed of granular "rock" as the filtration medium through which the flue gas must travel. These systems are electrostatically augmented (10 to 20 watts/1000 acfm). A high voltage (about 50 kV) is applied to an electrical conductor positioned within the bed and this creates an electrical field between the conductor and the inlet and outlet louvers. Particulate collection efficiencies for wood-fired boilers range from 65 to 95% for two multiclones in series, over 90% for wet scrubbers, from 93 to 99.8% for ESPs and FFs and about 95% for EGFs. Once again, it should be noted that most wood-fired boilers are combination boilers that may burn other sulfur-containing fuels. Thus, a change in the control device might affect the ability to control other pollutants. For example, replacing a wet scrubber with an ESP for better PM control would result in higher SO₂ emissions from a boiler burning wood in combination with oil or coal.

5.0 Other Source Emissions

5.1 Slakers - PM emissions

Slakers are generally vented through a stack to discharge the large amounts of steam generated. The steam may contain particulate matter, which is largely calcium and sodium carbonates and sulfates. Scrubbers are generally employed to capture this particulate matter. Other PM control devices such as ESPs and fabric filters are both technologically infeasible (very high moisture source) and not cost effective.

5.2 Smelt Dissolving Tanks - PM Emissions

As with the recovery furnace, particulate emissions from smelt tanks are comprised of mainly sodium compounds with much lesser amounts of potassium compounds and some other trace metal compounds. The dominant compound is sodium carbonate, followed by sodium sulfate. Roughly 90% (by weight) of the particles have equivalent aerodynamic diameters under 10 µm, and 50% have diameters under 1 µm. Most smelt tank PM emissions are controlled by wet scrubbers, many of which are wetted fan scrubbers that are very effective in removing fine particulate. A dry ESP is once again infeasible as an option due to the high moisture content of the gases. The wet scrubber also serves to control total reduced sulfur compound emissions through pH control, thus replacing it with a wet ESP is not an option. As noted for other kraft mill sources, MACT II Implementation in 2004 has also resulted in significantly reduced allowable PM emissions from smelt dissolving tanks.

Appendix C

Modeling Archive CD Available on Request from MDE