



**NORTH CAROLINA
DEPARTMENT OF ENVIRONMENT AND NATURAL RESOURCES
DIVISION OF AIR QUALITY**

**BEST AVAILABLE RETROFIT TECHNOLOGY
PRELIMINARY DETERMINATION**

FOR

**BLUE RIDGE PAPER PRODUCTS
CANTON, HAYWOOD COUNTY
NORTH CAROLINA**

**THIS REVIEW WAS PERFORMED BY THE
AIR PERMITS SECTION
IN ACCORDANCE WITH 15A NCAC 2D .0543
“BEST AVAILABLE RETROFIT TECHNOLOGY”**

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SECTION 1.0

INTRODUCTION

The Blue Ridge Paper Products= (BRPP) Canton facility is a bleached kraft pulp mill producing bleached kraft softwood and hardwood pulp, paper and paperboard. Existing sources include: five power boilers, a batch digester and brownstock washer system, two recovery boilers, black liquor evaporator system, turpentine recovery system, two lime kilns, a chlorine dioxide generator, two pulp bleaching systems, three paper machines and a paperboard dryer. The facility is a Title V facility and operates under air permit 08961T08. BRPP submitted a BART evaluation Permit Application to the North Carolina Department of Environment and Environmental Resources Division of Air Quality Division of Air Quality (NCDAQ) on November 16, 2007.

The requirements for Best Available Retrofit Technology (BART) are set forth in 15A NCAC 2D .0543 “Best Available Retrofit Technology.” This rule, currently State-Only enforceable, implements the BART provisions of 40 CFR 51.301 for emission sources that may cause or contribute to any visibility impairment in a mandatory Class I federal areas as determined using 40 CFR 51, Subpart P. “BART-eligible” sources are those sources built between 1962 and 1977 that have the potential to emit more than 250 tons per year of one or more visibility-impairing compounds including sulfur dioxide (SO₂), nitrogen oxides (NO_x), particulate matter (PM), and volatile organic compounds (VOCs), and that fall within 26 industrial source categories (including Kraft pulp and paper manufacturing). A review of the emission sources found that there were five emission sources that were BART eligible: Recovery Boiler 10, Recovery Boiler 11, No. 10 smelt dissolving tank, No. 11 smelt dissolving tank, and the Black Liquor Oxidation System.

Under the authority of 15A NCAC 2D .0543(c), a BART-eligible source can be exempted from the BART requirements based on dispersion modeling demonstrating that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. The emissions from these sources were modeled using CALPUFF to determine if the emissions from the BART eligible emission sources contributed to perceptible visibility impairment to Class I areas. The results of this modeling indicated that there was a significant impact from these sources to the Great Smokey Mountains and the Shining Rock Class I areas. Since these emission sources could not be otherwise exempted from BART, a BART analysis was conducted in accordance with the requirements set forth in 15A NCAC 2D .0543.

1.1 BART Determination

The NCDAQ has made the determination that BART for the affected emission sources is no additional controls. Therefore, the NCDAQ proposes to issue an air permit with a specific permit condition that notes that the permittee has satisfied all of the requirements for BART and that no additional controls are necessary. The remainder of this report contains a review by NCDAQ of the demonstration and analyses presented by Blue Ridge Paper Products. The response to EPA and the National Park Service comments on the BART Permit application may be found in Appendix A. Appendix B contains the NCASI Corporate Correspondents Memorandum on

retrofit controls.

BART will be implemented through a modification to Blue Ridge Paper Products Title V air permit. The Title V air permit application implementing BART must undergo adequate public participation. The NCDAQ solicits and encourages participation by the general public, industry, and other affected persons. Specific public notice requirements and a 30-day public comment period are required before the NCDAQ can take final action on this application. Appendix C contains a copy of the public notice.

SECTION 2.0

2.1 BART Affected Units

“BART-eligible” sources are those sources built between 1962 and 1977 that have the potential to emit more than 250 tons per year of one or more visibility-impairing compounds including sulfur dioxide (SO₂), nitrogen oxides (NO_x), particulate matter (PM), and volatile organic compounds (VOCs), and that fall within 26 industrial source categories (including Kraft pulp and paper manufacturing). The Blue Ridge Paper Canton Mill has 5 BART-eligible units:

- **No. 10 Recovery Furnace (10REC):** The No. 10 Recovery furnace has a nominal black liquor solids firing rate of 121,000 pounds of black liquor solids per hour and can fire fuel oil during start-up, shutdown, and malfunction (SSM) at a nominal heat input rate of 382 MMBtu/hr. The unit is controlled by an electrostatic precipitator. This unit is subject to MACT standards at 40 CFR 63, Subpart MM, and its PM emissions are approximately 10 percent of the single source recovery furnace limit of 0.044 gr/dscf. The unit was constructed in 1964.
- **No. 11 Recovery Furnace (11REC):** The No. 11 Recovery furnace was constructed in 1973 and has a nominal black liquor solids firing rate of 121,000 pounds of black liquor solids per hour and can fire fuel oil during start-up, shutdown, and malfunction (SSM) at a nominal heat input rate of 382 MMBtu/hr. The unit is controlled by an electrostatic precipitator. This unit is subject to MACT standards at 40 CFR 63, Subpart MM, and its PM emissions are approximately 15 percent of the single source recovery furnace limit of 0.044 gr/dscf.
- **No. 10 Smelt Dissolving Tank (10SDT):** This smelt dissolving tank serves the No. 10 Recovery Furnace and was installed in 1964. This unit is controlled by a chevron mist eliminator. This unit is subject to MACT standards at 40 CFR 63, Subpart MM.
- **No. 11 Smelt Dissolving Tank (11SDT):** This smelt dissolving tank serves the No. 11 Recovery Furnace. This unit is controlled by a chevron mist eliminator. This unit is subject to MACT standards at 40 CFR 63, Subpart MM. The unit was constructed in 1973.
- **Black liquor oxidation system (BLOX):** The black liquor oxidation system precedes the two recovery furnaces and is in place to reduce Total Reduced Sulfur (TRS) emissions from the recovery furnaces by oxidizing the black liquor. This system is controlled by a Regenerative Thermal Oxidizer (RTO) and wet scrubber; therefore, the RTO scrubber stack parameters and emission rates were included in this analysis. This unit is subject to MACT standards at 40 CFR 63, Subpart S, via 40 CFR 63.94, Equivalency by Permit. The BLOX system was originally installed in 1964.

These units are part of the mill’s chemical recovery system, which is an integral part of the Kraft pulping process. Although the recovery furnaces do produce steam for process operations, their primary purpose is chemical recovery, and are collectively controlled below the chemical recovery source MACT emission limits set forth in 40 CFR 63 Subpart MM. In addition, the BLOX will be controlled by a regenerative thermal oxidizer (RTO) to reduce HAP emissions under MACT Subpart S, followed by a wet scrubber to minimize SO₂ emissions from combustion of sulfur compounds in the BLOX gases in order to not be considered a significant

modification under NSR PSD. Therefore, the 5 BART-eligible emission units at the Blue Ridge Canton Mill are already well-controlled units.

2.2 BART exemption modeling analysis

The first step of the BART process was to determine if any of the affected BART-eligible sources could be exempted based on their contribution to visibility impacts on Class I areas. According to 40 CFR Part 51, Appendix Y, a BART-eligible source is considered to “contribute” to visibility impairment in a Class I area if the modeled 98th percentile change in deciviews¹ (dv) is equal to or greater than the “contribution threshold.” The contribution threshold is understood to be 0.5 deciview and a threshold of 1.0 deciview is understood to cause visibility impairment. Any BART-eligible source determined to cause or contribute to visibility impairment in any Class I area is subject to a BART evaluation.

Blue Ridge submitted a modeling protocol to NCDAQ on January 31, 2006. The objective of the modeling protocol was to obtain approval from NCDAQ on the modeling procedures that were used to conduct the BART exemption modeling for the Blue Ridge Canton Mill. The protocol incorporated guidance developed by VISTAS for conducting a BART modeling analysis and proposed a more refined line-of-sight modeling approach. The protocol presented detailed explanations of both modeling procedures. However, the BART determination was based on the VISTAS modeling protocol. The results of the exemption modeling of the combined BART eligible units are shown in the following table.

Summary of Exemption Modeling Results for BART Eligible Sources at the Canton Mill

Class I Area	Delta Deciview (dv) ¹
	Standard (VISTAS) Approach
Shining Rock	2.887
Great Smoky Mountains	0.764
Linville Gorge	0.155
Joyce Kilmer	0.134
Cohutta	0.095

¹ – Delta deciview as compared to natural conditions.

¹ *Deciview* means a measurement of visibility impairment. A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired. The deciview haze index is calculated based on the following equation (for the purposes of calculating deciview, the atmospheric light extinction coefficient must be calculated from aerosol measurements):

$$\text{Deciview haze index} = 10 \ln_e(b_{\text{ext}}/10 \text{ Mm}^{-1}).$$

Where b_{ext} = the atmospheric light extinction coefficient, expressed in inverse megameters (Mm^{-1}).

The results of the exemption modeling indicate that, since the emissions from the BART eligible emission sources exceed the 0.5 dv contribution threshold for two Class I areas, a BART evaluation must be conducted for each of the five emission sources.

SECTION 3.0

REGULATORY ANALYSIS

3.1 Federal BART Applicability and Required Analysis

The Clean Air Act established goals for visibility in many national parks and wilderness areas. Through the 1977 amendments to the Clean Air Act, Congress set a national goal for visibility as “the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution.” The Amendments required EPA to issue regulations to assure “reasonable progress” toward meeting the national goal. The Class I Areas affected by this facility are the Shining Rock and the Great Smoky Mountains National Parks.

One of the principal elements of the visibility protection provisions of the Clean Air Act addresses installation of best available retrofit technology (BART) for certain existing sources. “BART-eligible” sources are those sources built between 1962 and 1977 that have the potential to emit more than 250 tons per year of one or more visibility-impairing compounds including sulfur dioxide (SO₂), nitrogen oxides (NO_x), particulate matter (PM), and volatile organic compounds (VOCs), and that fall within 26 industrial source categories (including Kraft pulp and paper manufacturing).

The BART requirements are found in 40 CFR 51.308(e) “*Best Available Retrofit Technology (BART) requirements for regional haze visibility impairment.*” In addition, the final BART implementation and guidance (40 CFR Part 51, Appendix Y) published on July 6, 2005 and allow for a BART evaluation for any BART-eligible source that “emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility” in any mandatory Class I federal area. The guidance (Appendix Y) must only be followed by states for large fossil fuel fired electric steam generators, but is otherwise optional for other potential BART units.

According to Appendix Y, a BART-eligible source is considered to “contribute” to visibility impairment in a Class I area if the modeled 98th percentile change in *dv* is equal to or greater than the “contribution threshold.” The contribution threshold is understood to be 0.5 deciview and a threshold of 1.0 deciview is understood to cause visibility impairment. Any BART-eligible source determined to cause or contribute to visibility impairment in any Class I area is subject to a BART evaluation.

Based on the results of the BART evaluations, States will develop Regional Haze State Implementation Plans (SIPs). States must submit plans to implement the Regional Haze Rule for EPA review and approval by January 2008.

3.2 North Carolina BART Applicability

The BART requirements are implemented through 15A NCAC 2D .0543 “Best Available Retrofit Technology.” This rule implements the BART provisions of 40 CFR 51.301 for emission sources that may cause or contribute to any visibility impairment in a mandatory Class I federal area as determined using 40 CFR 51, Subpart P. There five emission sources that are BART eligible: Recovery Boiler 10, Recovery Boiler 11, No. 10 smelt dissolving tank, No. 11 smelt dissolving tank, and the Black Liquor Oxidation System.

Under the authority of 15A NCAC 2D .0543(c), a BART-eligible source may be exempted from the BART requirements based on dispersion modeling demonstrating that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. The results of this modeling indicated that there was a significant impact from these sources to the Great Smokey Mountains and the Shining Rock Class I areas. Since these emission sources could not be otherwise exempted from BART, a BART analysis was conducted in accordance with the requirements set forth in 15A NCAC 2D .0543.

3.3 Required Air Quality Permits

The BART requirements, if any, will be implemented through the Title V permitting process. Since BART will not be required for any of the BART-eligible sources, the Title V permit will be modified to indicate that there are no applicable BART requirements for the BART-eligible emission sources at Blue Ridge Paper products.

SECTION 4.0

BEST AVAILABLE RETROFIT TECHNOLOGY ANALYSIS

4.1 Summary

The sources subject to the Best Available Retrofit Technology (BART) requirements include the two recovery boilers, their associated smelt dissolving tanks, and the BLOX. This section presents the BART analyses for these emission sources, since they could not be otherwise exempted based on emission modeling. This BART evaluation has concluded that BART for all of these emission sources are the existing emission control systems.

4.2 BART Analysis Overview

BART is defined as follows [40 CFR 51.301]:

“Best Available Retrofit Technology (BART) means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.”

The BART analysis was conducted with consideration of the six requirements identified above and the five steps identified in 40 CFR 51 Appendix Y “Guidelines for BART Determinations Under the Regional Haze Rule.” Again, these guidelines are not the exclusive means of defining BART for facilities other than Electric Generating Units. However, they provide a convenient structure to consider.

- Step 1—Identify All Available Retrofit Control Technologies,
- Step 2— Eliminate Technically Infeasible Options,
- Step 3— Evaluate Control Effectiveness of Remaining Control Technologies,
- Step 4— Evaluate Impacts and Document the Results, and
- Step 5—Evaluate Visibility Impacts.

Each of these steps is discussed in further detail in the sections presented below.

4.2.1 Step 1 – Identify All Available Retrofit Control Technologies

Appendix Y to 40 CFR 51 defines an available retrofit control option as an air pollution control technology with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Technologies available for compliance with Best Available Control

Technology (BACT) or Lowest Achievable Emission Rate (LAER) regulations should be included as part of the BART analysis. Furthermore, technologies that are evaluated should include existing controls for the source category in question as well as the transfer of controls that have been applied to similar source categories and gas streams. However, control technologies which have not yet been applied to full scale operations are not required to be included in the evaluation.

Potentially applicable control technologies can be grouped into one of three categories:

- Pollution Prevention. As stated in the regulation this is *“use of inherently lower-emitting processes/practices, including the use of control techniques (e.g., low-NO_x burners) and work practices that prevent emissions and result in lower “production-specific” emissions.”*
- Add-on Control Technologies. *“Use of (and where already in place, improvement in the performance of) add-on controls, such as scrubbers, fabric filters, thermal oxidizers and other devices that control and reduce emissions after they are produced.”*
- Combinations of the previous two categories.

Sources that were used to determine the potentially applicable control technologies for the Blue Ridge BART analysis include the Environmental Protection Agency’s RACT/BACT/LAER Clearinghouse (RBLC), control technology vendors, and information supplied by the National Council for Air and Stream Improvement (NCASI).

4.2.2 Step 2 – Eliminate Technically Infeasible Options

Step 1 of the BART analysis identifies all of the control technologies that are potentially available for the BART eligible emission units. In step 2 of the analysis this list is further refined to include only those technologies that are technically feasible. Appendix Y of 40 CFR 51 defines a technically feasible control technology as:

“Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: “availability” and “applicability.” ...a technology is considered “available” if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.”

Control technologies that are deemed technically infeasible in this step of the evaluation must include specific data stating that the technology is either commercially unavailable or outline the specific circumstances which preclude its application. Facilities may demonstrate that a particular technology is infeasible due to *“unresolvable technical difficulties with applying the control to the source (e.g., size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability, and adverse side effects on the rest of the facility).”*

Implications of cost effectiveness should not be included in this step of the analysis.

4.2.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Control technologies determined to be technically feasible in step 2 of the analysis are further evaluated in step 3. The two main issues in step 3 of the process are as follows:

- Making sure that you express the degree of control using a metric that ensures an “apples to apples” comparison of emissions performance levels among options, and
- Giving appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels.

The analysis should be based on the maximum level of control that a technology is capable of achieving.

4.2.4 Step 4 – Evaluate Impacts and Document the Results

For the control technologies determined to be commercially available and technically feasible, the affected facility must conduct the following analyses to select the control technology that meets the requirements of BART.

The analysis evaluates four impacts that would potentially result from the installation of a control technology.

- Impact analysis part 1: Costs of compliance,
- Impact analysis part 2: Energy impacts,
- Impact analysis part 3: Non-air quality environmental impacts, and
- Impact analysis part 4: Remaining useful life.

Appendix Y to 40 CFR 51 presents detailed guidance for conducting the evaluation of each potential impact. The analysis presented later in this section for each available and technically feasible control technology identified for the BART eligible emission units follows these guidelines.

4.2.5 Step 5 – Evaluate Visibility Impacts

Once the facility has completed the steps outlined above and an available, technically feasible control technology has been selected, then the visibility improvements are evaluated in this final step.

Baseline emissions and the visibility impacts are compared to the predicted visibility impacts from the emission sources with the control technology installed. If the net visibility improvement is less than that which would contribute to visibility impairment (as defined in the preamble to Appendix Y) then there is no need for the facility to implement the control technologies because the resulting visibility impacts would be negligible.

4.3 BART Analysis for Recovery Boilers

Blue Ridge operates two recovery furnaces at the Blue Ridge Canton Mill. Each unit is permitted to fire 121,000 pounds of black liquor solids per hour. The units are capable of firing fuel oil during startup, shutdown, and malfunction. Each unit is currently equipped with an electrostatic precipitator (ESP), and the emissions from each of these units exceed the PM control requirements of 40 CFR 63, Subpart MM (MACT II).

It is important that the use and function of the recovery furnace in the pulp and paper process is properly understood. The recovery furnace performs the following functions:

- Evaporates residual moisture from the black liquor solids,
- Combusts organic constituents in the black liquor,
- Reduces oxidized sulfur compounds to sulfide,
- Recovers inorganic chemicals (smelt) in molten form. This smelt is dissolved in the smelt dissolving tanks and returned to the process,
- Conditions the products of combustion to minimize chemical carryover, and
- Generates additional steam for mill processes.

The primary purpose of a recovery furnace is not to produce steam, but for chemical recovery that is inherent to the operation of the Kraft pulping process with steam a byproduct.

The recovery furnaces emit PM, SO₂, and NO_x. Each of these units are equipped with an ESP that exceeds the particulate emission requirements of 0.044 gr/dscf at 8% O₂ for MACT 40 CFR 63 Subpart MM. Recent stack testing performed to demonstrate compliance with MACT Subpart MM showed particulate emissions of 0.004 gr/dscf at 8% O₂ for No. 10 Recovery Furnace and 0.007 gr/dscf at 8% O₂ for No. 11 Recovery Furnace. Therefore, potential retrofit control technologies for particulate matter emissions from the recovery furnaces were not further evaluated since the units are already equipped with the most stringent controls and the operation of these controls is required by the facility's Title V Operating Permit.

4.3.1 BART Analysis for NO_x emission control

Compared to a typical power boiler, emissions of NO_x from a recovery furnace are generally quite minimal. The minimal NO_x emissions can be attributed to four main mechanisms within the furnace.

- The as-fired nitrogen content of most black liquor solids is less than 0.2% by weight.
- The temperature profiles within the furnace generally do not promote the formation of thermal NO_x.
- The introduction of combustion air within the furnace is staged.

There are several NO_x control technologies that are potentially applicable to combustion sources based on reviews of similar processes and a review of the RBLC database.

1. Low NO_x Burners (LNB) – The use of low NO_x burners is a demonstrated technology installed on many fossil-fuel combustion sources. However, this is not a demonstrated

technology for a recovery furnace. Black liquor has a large amount of water. Consequently, the drying, pyrolysis, and char burning of liquid droplets occurs over an extended trajectory from the liquor guns to the char bed. Therefore, the benefits of a low NO_x burner would not be realized in a recovery furnace. Furthermore, the recovery furnace is already equipped with primary, secondary, and tertiary air which provides inherent NO_x control.

2. Flue Gas Recirculation (FGR) – FGR involves the recirculation of a portion of the exhaust gas back into the combustion zone of the furnace. This control technology is aimed toward minimizing the formation of thermal NO_x. However, as previously stated thermal NO_x emissions from a recovery furnace are minimal. Therefore, installation of this control technology would not result in significant NO_x reductions and is not considered further.
3. Water Injection – This control technology is generally applied to natural gas-fired boilers for the control of NO_x emissions. The introduction of water droplets into the combustion zone of a recovery furnace could lead to an explosive condition inside the unit. Therefore, water injection is not technically feasible.
4. Add-on NO_x Controls – This category involves the evaluation of both Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). In the SNCR process, urea or ammonia would be injected into the recovery furnace. No long-term evaluations have been conducted for a SNCR installation on a recovery furnace. Since the primary purpose of the recovery furnace is chemical recovery there are concerns that the introduction of additional chemicals into the process could have a harmful effect on the quality of the smelt produced.

SCR involves passing the exhaust stream over a catalyst to reduce NO_x emissions. The SCR system can either be installed prior to the ESP (High Dust application) or after the ESP (either hot side or cold side). The problem associated with this control technology involves possible catalyst fouling from entrained particulate if the unit were installed prior to the ESP. If the SCR were installed after the ESP, the gas stream will be too cool to effectively react with the NO_x without flue gas reheating. Therefore, both of these options are considered technically infeasible.

5. Staged Combustion – This involves adding a quaternary zone of combustion air within the recovery furnace. There have been limited demonstrations of this technology on a short-term basis. A 20-40% reduction in NO_x emissions was observed. Therefore, this control technology is the only option identified as technically feasible for NO_x reduction from recovery furnaces and has been evaluated further as part of the BART process.

Mill personnel investigated the potential installation of **quaternary air** within each recovery furnace along with the installation of new liquor fuel guns. Cost estimates provided by Mill personnel indicate that the total capital costs associated with the modification would be approximately \$9 million for both furnaces. In addition to the capital and installation costs, each recovery furnace would be out of service for one month while the modification was being made. Therefore, during these periods, the pulp mill could only operate at one-half capacity and the mill would have to purchase dry furnish at a cost of approximately \$23.1 million in order to maintain paper production. Therefore, the total costs associated with the implementation of this

control technology on both furnaces are \$32.1 million. The annualized costs for NO_x removal were estimated to be \$3,839,996 for each recovery boiler.

Based on an expected NO_x reduction efficiency of 40% (a reduction of 230 tons per recovery furnace), the cost effectiveness per ton of NO_x removed using **quaternary air** would be approximately \$16,700 per ton.

There are no additional impacts anticipated from the modification (i.e., water, additional power, etc.).

The anticipated visibility impacts from a 40% reduction in NO_x emissions from the recovery furnaces were estimated to be a 0.371 deciview improvement over the current conditions. The cost of this retrofit would be extremely high, at \$44,994/ton/dv.

The number of days with an estimated visibility greater than 0.5 deciview impact at the baseline operating conditions was estimated to be 86 days at Shining Rock and 18 days at Great Smoky Mountains. The installation of quaternary air in the recovery furnaces would only slightly reduce the number of days greater than 0.5 deciview impact at Shining Rock to 82 days and 15 days at Great Smoky Mountains.

Based on the above analysis, the NCDAQ believes that the installation of NO_x reduction controls for the recovery furnaces is not economically feasible.

4.3.2 BART Analysis for SO₂ emission control

The inlet loading of sulfur is significant, normally in the range of 3-5% by weight. One of the primary purposes of the recovery furnace is to recover and convert oxidized sulfur compounds to sulfide. The majority of this sulfur is contained in the smelt leaving the furnace; however, a small fraction of the compound can be emitted in the form of SO₂. There are a number of factors which are thought to influence the formation of SO₂ in the recovery furnace; however, a direct relationship has not been established.

A review of the RBLC database shows that there are no add-on control technologies that have been installed solely for the control of SO₂ emissions.

An additional source of information on emissions controls is the National Council of Air and Stream Improvement (NCASI) Corporate Correspondents Memorandum CC 06-014 entitled "*Retrofit Control Technology Assessment for NO_x, SO₂, and PM Emissions from Kraft Pulp and Paper Mill Unit Operations.*" A copy of this memorandum is included in **Appendix D**. As the environmental control reference organization for the pulp and paper manufacturers, NCASI follows the industry closely and is aware of the control measures that are currently employed. This document further iterates that there are no control measures specific to SO₂ employed by the pulp and paper industry on recovery furnaces. According to NCASI, the few wet scrubbers that have been installed on recovery furnaces in the pulp and paper industry have been installed for additional particulate control following an ESP (e.g., for PSD avoidance), although there is some residual SO₂ removal from the units.

However, the installation of a wet scrubber following the ESP on a recovery furnace is technically feasible, although it would be a complicated and costly retrofit for the recovery furnaces at the Blue Ridge Canton Mill. Once a technically feasible control technology has been determined, it is necessary to begin evaluating the additional impacts as described in step 4 of the BART procedures.

The first impact to be evaluated is the potential cost associated with the installation of the scrubber. Vendors were contacted by the mill for a similar project and given information regarding the composition of the gas stream and the estimated volumetric flow rate. The cost of a wet scrubber was obtained from Monsanto Enviro-Chem. Based on this budgetary capital cost estimate, additional expenses associated with installation of the device were estimated. The source of these estimates is both historical mill experience and EPA's Control Cost Manual. It is important to note that the Blue Ridge Canton Mill was originally constructed in 1905, and subsequent modifications have left the facility extremely "land-limited." The ESPs for the two furnaces are located on the top of the recovery building, but there is no room on the roof of this building for two scrubbers. Therefore, the installation of a new scrubber on each recovery furnace would require extensive piping and ductwork modifications. The closest location to the recovery furnaces for the possible installation of a scrubber would require over 300 feet of stainless steel ductwork including a bridge to elevate the ductwork over roadways. Additionally, a new fan would be required to move the exhaust through the new ductwork and scrubber to overcome the additional pressure loss. Not only would there be capital costs associated with the installation of a fan, but the current power distribution system is operating at maximum capacity and a new switch gear would be required.

The expenses associated with the wet scrubber includes capital costs associated with the purchase and installation of the new equipment and the cost associated with the purchase of pulp to replace lost production during the period of construction. The capital costs for the installation of a wet scrubber achieving 90% SO₂ removal from a recovery boiler was estimated to be \$26,293,000, and annualized costs at \$6,897,430. The cost effectiveness per ton of SO₂ removed was estimated at \$13,643 per ton. Incremental cost effectiveness per ton of pollutant removed was not calculated because only one control technology has been identified as technically feasible.

Operation of a wet scrubber will have an impact on energy consumption and will have secondary environmental impacts to the air, water, and soil. Operation of the scrubber will require additional electricity. This power would either be generated onsite or be purchased from the grid and would have an associated air emissions impact from either the onsite boilers or the power generation facility located nearby. In addition, the wet scrubber system will require additional water usage and will generate gypsum (calcium sulfate) that will require solid waste disposal. As outlined in the BART evaluation process, the final step that must be conducted is the evaluation of potential improvements to visibility.

The results of the visibility analysis resulting from the installation of wet scrubbers on the recovery boilers and the current configuration for the smelt dissolving tanks and the BLOX system demonstrates that the installation of wet scrubbers on the recovery furnaces does not result in a visibility improvement at the Shining Rock Class I area. This scenario actually causes

a higher delta deciview impact than the modeled current conditions. The number of days with an estimated visibility greater than 0.5 deciview at the baseline operating conditions was 86 days at Shining Rock and 18 days at Great Smoky Mountains. The installation of wet scrubbers would actually increase the number of days greater than 0.5 deciview impact at Shining Rock to 91 days. However, a slight decrease may be seen at Great Smoky Mountains with only 9 days greater than 0.5 deciview impact.

Based on the fact that the installation of a wet scrubber for SO₂ control is not economically feasible and would result in only a marginal visibility improvement at one Class I area and a degradation in visibility at another, retrofit controls are not warranted for SO₂ emissions from the recovery furnaces.

4.4 BART Analysis for Smelt Dissolving Tanks

The smelt generated in the recovery furnaces is discharged into a tank where large chunks are broken into smaller pieces by a steam jet. Weak wash water is added to the vessel to create green liquor which is further processed in the causticizing system to create white liquor for reuse in the pulping process. There are minimal emissions of NO_x, SO₂, and particulate from the smelt dissolving tanks. Blue Ridge Paper does not have site-specific NO_x and SO₂ measurements from the smelt tanks, but is using published emission factors from NCASI Technical Bulletin 884 to estimate emissions of these compounds. As no combustion occurs in the smelt tanks, NCASI believes that the small emissions of NO_x and SO₂ sometimes measured may be a result of oxidation of ammonia emissions within the NO_x analyzer and oxidation of sulfur in the smelt during smelt-water explosions. Each unit is currently equipped with a chevron mist eliminator for reduction of emissions of particulate and complies with MACT standards for PM.

4.4.1 Bart Analysis for SO₂ and PM Emissions

A review of the RBLC database indicates that smelt dissolving tanks located at other pulp and paper facilities utilize proper operation and wet scrubbers for the minimization of particulate and SO₂ emissions. However, emissions from these units are minimal and are emitted at relatively low velocities which limits the control technologies that are technically feasible. Blue Ridge personnel have investigated improvements to the current control system design that involve installation of “micro mist” nozzles to improve the PM control efficiency. Capital costs associated with the scrubber upgrades for a 50% removal in both PM and SO₂ are estimated at \$250,000 per scrubber, with an annualized cost of \$197,862. The estimated cost effectiveness for 50% SO₂ control is \$301,160/ton SO₂ removed. The estimated cost effectiveness for 50% PM control is \$13,862.

As was done for the previously evaluated technically feasible control technologies, the visibility improvements that may be obtained from modifications to the current smelt tank scrubbers was investigated. A 50 percent improvement over current SO₂ and PM emissions would result in a 0.029 deciview improvement could be seen after modifying the scrubbers. The cost is \$10,384,813/ton/dv for SO₂ and \$478,016/ton/dv for particulate.

The number of days with an estimated visibility greater than 0.5 deciview impact at the baseline operating conditions is 86 days at Shining Rock and 18 days at Great Smoky Mountains. The installation of micromist scrubbers on the smelt tanks would only minimally reduce the number of days greater than 0.5 deciview impact at Shining Rock to 79 days and 17 days at Great Smoky Mountains.

Based on the above analysis, the NC DAQ believes that the installation of retrofit controls on the smelt dissolving is not economically feasible.

4.4.2 BART Analysis for NO_x emission control

There are no control technologies to reduce NO_x emissions that are available for installation on a smelt dissolving tank. A review of the RBLC database shows that only proper operation and good recovery furnace combustion techniques have been determined as BACT for NO_x emissions from smelt tanks. NCASI is not aware of any smelt tanks with NO_x controls installed. Therefore, no further evaluation was conducted for NO_x control technologies for the smelt dissolving tanks.

4.5 BART Analysis for Black Liquor Oxidation System

On April 15, 1998, the EPA promulgated National Emission Standards for Hazardous Air Pollutants (NESHAP) from the Pulp and Paper Industry (40 CFR 63, Subpart S). Under 40 CFR 63.94, the North Carolina Department of Environment and Natural Resources (NC DENR) requested approval from EPA to implement alternative requirements in the form of permit terms and conditions instead of the requirements in 40 CFR 63, Subpart S. This alternate process is called equivalency by permit (EBP). The EPA has approved this request with an effective date of June 11, 2004. Blue Ridge Paper submitted an application on June 17, 2004 to request approval of an alternate compliance approach to that required in 40 CFR Subpart S for the high-volume, low-concentration (HVLC) sources (referred to as MACT I, Phase 2).

This alternate compliance approach, which was approved by EPA on March 10, 2005, will allow the Blue Ridge Canton Mill to achieve a greater level of hazardous air pollutant (HAP) emission reduction, additional significant environmental benefits such as total reduced sulfur (TRS) compound emissions reductions, and community/industrial economic sustainability results not achieved under 40 CFR 63.443. In lieu of controlling pulp mill HVLC sources under 40 CFR 63.443, the Blue Ridge Canton Mill received authorization to achieve a greater level of HAP reduction by controlling emissions from the black liquor oxidation (BLOX) system in a new regenerative thermal oxidizer (RTO) equipped with a wet scrubber for SO₂ control. The modeled SO₂ emissions represent the vendor-guaranteed emission rate at the scrubber outlet. PM and NO_x emissions are minimized by proper operating of the RTO and combustion of natural gas as auxiliary fuel, and no further controls are feasible. The construction of the RTO/Scrubber has been completed and the equipment they were fully operational prior to the MACT compliance date of April 17, 2007.

DAQ has determined that no further analysis of control technologies is required because the unit is already equipped with the most stringent controls as required by the MACT standards and permit limits are in place to ensure these controls are operated properly. Therefore, DAQ has determined that BART for the BLOX is no further controls.

APPENDIX A

Response to EPA and NPS Comments on BART Permit Application



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

Wallace

Ms. Sheila Holman
Division of Air Quality
North Carolina Department of Environment
and Natural Resources
1641 Mail Service Center
Raleigh, NC 27699-1641

Dear Ms. Holman:

Thank you for the opportunity to review the proposed Best Available Retrofit Technology (BART) technology evaluation for the Blue Ridge Paper – Canton Mill (Blue Ridge) dated November 16, 2006. With the significant visibility impacts modeled for this facility, we believe that it is important that thorough consideration be given to all the various options for installing available retrofit control technologies at this facility.

Enclosed are our comments on the Blue Ridge document. Enclosure 1 describes our comments on the control and cost analyses. Enclosure 2 details our comments on the modeling analysis. Enclosure 3 provides some clarifications to certain statements addressed in the Blue Ridge document.

We appreciate your transmittal of this package for our consideration. If you have any further questions regarding this letter, please contact Michele Notarianni of the Region 4 staff at (404) 562-9031.

Sincerely,

A handwritten signature in cursive script that reads "Kay T. Prince".

Kay T. Prince
Chief
Air Planning Branch

Enclosures

Enclosure 1: Control and Cost Analyses

1. Pollution Prevention (P2) Options:

- When identifying all available retrofit control technologies, the "Guidelines for BART Determinations Under the Regional Haze Rule" (BART Guidelines) clarify that consideration should be given not only to add-on controls but also improvement in the performance of existing controls and P2. The analysis does not discuss the facility's evaluation of any P2 options for the five BART-eligible units, with the exception of installation of quaternary air on each recovery furnace (RF).

2. Process Changes to Reduce Formation of Emissions from RFs:

- Although Table 4-1 indicates that several kraft pulp and paper mills utilize good combustion control practices to minimize sulfur dioxide (SO₂) emissions from their RFs, there is no discussion of what options may exist for making process changes, such as improved furnace design and operation, to limit the formation of SO₂ in each RF. An effective approach to minimizing the formation of SO₂ in the RFs would be to practice high dry solids firing combined with a modern air system to promote efficient mixing. Examples of process changes which have been demonstrated are identified in section 5.3.1 of "Assessment of Control Options for BART Eligible Sources," prepared by NESCAUM, for the Mid-Atlantic/Northeast Visibility Union Regional Planning Organization: <http://www.nescaum.org/documents/bart-resource-guide/>. These examples include optimizing liquor and combustion air properties and firing patterns to maintain uniform temperatures in the lower part of the RF in order to reduce SO₂ emissions, and reducing liquor sulfidity to reduce SO₂ emissions from the RFs.

3. Control Option Alternatives:

- The document states that installation of add-on SO₂ controls on the RFs results in lower stack heights and a higher modeled delta deciview (dv) than current conditions due to decreased dispersion associated with scrubber exhaust characteristics. (Executive Summary) We believe this may be due to the effects of cooling the exhaust stream. The analysis does not discuss whether good engineering practice (GEP) was considered in the development of the new stack height for this SO₂ control.

4. Lost Production Costs:

- There is no indication of whether the facility considered ways to mitigate costs attributed to "Lost Production" listed in Table 4-2 (pulp purchase of \$5,390,000 plus \$975,843 for lost power generation per RF) and Table 4-4 (\$11,550,000 for pulp purchase for 30 days downtime per RF). For example, the effects on costs in Tables 4-2 and 4-4 if potential controls were installed during an already planned plant shutdown for maintenance, or when one of the RFs is off-line, should be addressed. Also, it is unclear why one month is

needed for each RF retrofit to install a quaternary air system, which results in significant lost production costs of purchased pulp in Table 4-4.

- When major work is done at a pulp and paper mill, the mill can often increase production significantly prior to and following the shut down to offset any lost production. It is not clear whether the facility considered this possibility and its effects on the lost production costs.
- Lost production costs listed in Table 4-2 and Table 4-4 should be excluded from the Total Capital Investment (TCI) costs. As noted under comment 5, lost production costs (such as lost power generation) are to be considered in the operation and maintenance cost estimates for the control and should not be considered in the capital cost estimates. By removing lost production costs from TCI, the administrative, property tax, insurance, and capital recovery costs will also need to be recalculated using the correct TCI since they are calculated as a percentage of TCI.
- To minimize lost power generation costs listed in Table 4-2, it is not clear whether the facility considered achieving some additional power generation from its power boilers during the retrofit period to offset the losses. The mill has five power boilers and generally a pulp and paper mill with multiple power boilers does not operate all the boilers at maximum capacity at the same time.

5. Contingency Costs in Table 4-2:

- In Table 4-2, the contingency factor of 15 percent should be justified. It is our understanding that a factor no higher than 10 percent would be considered acceptable for wet scrubber installation on a RF at a pulp and paper mill, and would be consistent with standard industry practice. Also, since this is a "turnkey" installation, it is unclear why such a high contingency factor is projected. Since no distinct retrofit factor is identified, it is possible that the facility may have merged the retrofit factor with the contingency factor, resulting in the 15 percent contingency factor used in Table 4-2. The *EPA Air Pollution Control Cost Manual* (Cost Manual), EPA/452/B-02-001, January 2002, distinguishes between the contingency and retrofit factors and recommends keeping them separate as follows. A retrofit factor should be reserved for those items directly related to the demolition, fabrication, and installation of the control system, and should not be double-counted again as part of a contingency factor. In this case, the additional ductwork, new stack, fan, and switch gear should be assigned to the retrofit factor since they are a necessary part of installing this control on an existing unit. A contingency factor should be applied to only those items that could incur a reasonable but unanticipated cost increase (i.e., outside of the contractor's control), and are not directly related to the retrofit factor elements just described. (See pages 2-28 to 2-30 in subsection 2.5.4.2 of Chapter 2, "Cost Estimation: Concepts and Methodology," (dated January 2002) in Section 1 of the Cost Manual.)

- The contingency factor calculations in Table 4-2 are not based on the correct line item costs and need to be redone. The factor was applied to the scrubber "installation cost," additional ductwork, new stack, fan, and switch gear, and lost power generation. This is incorrect for two reasons. First, the "installation cost" listed for the wet scrubber appears to also include the cost of the equipment. The contingency factor should be applied to the purchased equipment costs. However, installation costs are not to be included in contingency factor calculations. This should be corrected. The second reason the calculations are incorrectly applied is that the "14 days lost power generation" cost of \$975,843 should not be included in the "contingency" cost calculations. The Cost Manual describes contingencies as a category that covers unforeseen costs that may arise, such as delays encountered in start-up and increases in field labor costs. (See page 2-5, of Chapter 2, "Cost Estimation: Concepts and Methodology," (dated January 2002) in Section 1 of the Cost Manual.) Lost power generation is to be considered in the operation and maintenance cost estimates for the control and should not be considered in the capital cost estimates. We note that lost production in terms of pulp purchase correctly does not appear to be included in the contingency cost calculations.

6. RF Wet Scrubber Cost Considerations:

- Table 4-2 describes costs with wet scrubber installation on one of the RFs. Given the relatively high nature of costs for the modifications to existing ductwork and installation of a new stack, fan, and switch gear (totaling to \$11,945,605), consideration should be given to other, more cost effective options. For example, the feasibility and cost effectiveness of moving the road or other buildings to allow closer location of the wet scrubbers and avoid extensive ductwork could be considered.
- It would be helpful to have more information on the design of the wet scrubber analyzed. We are aware of at least one kraft pulp mill (i.e., the James River Camas Mill in Washington State) that has installed a cross-flow, packed bed scrubber following the RF electrostatic precipitator (ESP) as part of an energy recovery system. At that mill, caustic (sodium hydroxide or NaOH) is added to the scrubber liquid and the mill has claimed SO₂ reductions as a result. It is not clear whether the facility has considered installing a similar system.
- There is no discussion indicating whether the facility considered use of caustic as the scrubbing reagent instead of limestone. Kraft pulp mills have a relatively inexpensive supply of caustic available since it is used in the cooking liquor, which can make caustic more economical than limestone. Also, the use of caustic eliminates the material handling and space requirements associated with lime or limestone systems. Lime and limestone processes produce a sludge which requires dewatering and landfilling. Wet

caustic processes produce a neutral pH solution which can be pumped to the existing mill wastewater treatment system for disposal. Thus, the estimated annual costs would be greatly reduced by using a caustic scrubber instead.

- We suggest that the State closely evaluate the electricity costs for the RF scrubber. For example, the basis for the 746 kilowatt-hours used in Table 4-2 should be discussed. Other considerations should include the assumed pressure drop of the scrubber, and what portion of the electricity costs are associated with the use of limestone rather than caustic (e.g., limestone preparation and slurry mix system, gypsum filter system, etc.).

7. RF Quaternary Air System Cost Considerations:

- The capital cost estimate of \$9 million (includes quaternary air and new liquor guns for both RFs) cited on page 4-7 and detailed per RF in Table 4-4 seems extremely high. In 2001, the American Forest and Paper Association (AF&PA) commissioned BE&K Engineering to develop emissions control cost estimates for a variety of scenarios at pulp and paper mills, including the addition of a quaternary air system for reducing NO_x emissions from a RF. The model RF was larger than the RFs at Blue Ridge. Based on the AF&PA analysis, the capital cost for the quaternary air system was \$624,000 per furnace. Disregarding differences in size and base years, the total cost would be approximately \$1.2 million for two RFs, which is considerably less than the \$9 million quoted on page 4-7. It would be helpful if Blue Ridge could provide an estimate just for the addition of the quaternary air system, omitting the costs of the new liquor guns, to provide for a better comparison of costs.

8. Supporting Documentation for Cost Analyses:

- To aid review of the document, we suggest that the vendor quotes, data estimates, and relevant portions of the presentation identified in the cost references [1], [6], [7] in Tables 4-2 be included in this document. Also, it is unclear where the e-mail described in Reference 1 of Table 4-2 is located in the documentation so we were unable to review this reference.
- Reference 7 of Table 4-2 indicates that costs for wet scrubber installation are based on a vendor quote for an "original recovery furnace," which does not appear to be either of the RFs subject to this BART analysis. Although the facility adapted the cost estimate to the size of the No. 10 RF, we question why the facility did not seek a vendor quote for wet scrubber installation specific to the RFs subject to this BART analysis (i.e., No. 10 and No. 11). We recommend that a copy of the quote be included in the documentation to provide information such as what year the quote for the original RF was received.
- Reference 7 of Table 4-2 also states that, "Cost was escalated using EPA's 0.6 rule..." The "0.6 rule" referenced is to be used for a rough estimate calculation of costs only and should not be relied upon for this BART analysis

to estimate installation costs of the wet scrubber. Also, we are not aware that the "0.6 rule" is part of an EPA document. However, the book, *Plant Design and Economics for Chemical Engineers* by Peter and Timmerhaus (Fifth Edition) does discuss this "rule of thumb" and calls it the "six-tenths-factor" rule. (Peters, Max S., Timmerhaus, Klaus and West, Ronald. *Plant Design and Economics for Chemical Engineers*, Fifth Edition, McGraw-Hill, 2002, p. 169.)

9. Capital Recovery Factor (CRF) Calculations:

- The facility should justify its capital recovery cost assumptions of an equipment life of 10 years with an interest rate of 15 percent listed under "Indirect Annual Costs" in Tables 4-2, 4-4, and 4-6. For capital recovery costs on wet scrubbers for acid gas, the EPA Cost Manual and EPA's *Technical Support Document: Chemical Recovery Combustion Sources at Kraft and Soda Pulp Mills* (EPA-453/R-96-012, October 1996) presume a CRF based on a 15-year control equipment life and an interest rate of seven percent. Note that changing the assumptions about equipment life and interest rates to this presumptive value significantly decreases the annualized cost estimates.

Enclosure 2: Modeling Analysis

1. Table 5-1 indicates a 31.25-meter decrease in the stack heights for the No. 10 and 11 RFs' stack for Scenarios 2 and 5. It is unclear why a decrease in stack height is required or if this is a typographical error. Also, the analysis does not discuss whether GEP was considered in the development of the new stack height for this SO₂ control. According to Table 5-1, the modeled location of the stacks has not changed from the current location. Table 5-4 indicates that the maximum visibility impact has shifted slightly to another geographical location in the Shining Rock and Great Smoky Mountain Class I areas. With decreased SO₂ emissions from installation of the scrubber, the expected result is that the visibility impact should also decrease. The analysis should provide more discussion on how and where the visibility increases occurred in the Class I areas in addition to providing the maximum delta visibility impact and explain why a decrease in stack heights is necessary.
2. The NO_x emissions used in the baseline (i.e., Scenario 1) modeling was based on a February 1999 stack test. There is no discussion of why data from this year was used to the exclusion of data from other years. Such discussion should include such items as stack test data availability from other years and how this ensures that the maximum 24-hr emission rate for the 2001-2003 period was developed. We encourage the State to review these data to ensure the assumptions supporting the emission rates are correct and the supporting documentation is submitted.
3. A vendor guarantee was used to set the emission rate for the black liquor oxidation system (BLOX) regenerative thermal oxidizer (RTO) provided in Table 5-2 (reference 3). We suggest that the referenced guarantee be included in the document and recommend that the State carefully evaluate this rate in conjunction with the specified operating parameters to ensure appropriate values are being used in the BART modeling.
4. It may appear that the visibility improvements from the various control scenarios assessed do not indicate a desired level of benefit at two of the five Class I areas, but the other three Class I areas being affected by the facility could also be considered in the determination.
5. Addition of a wet scrubber should also reduce fine particulate matter (PM_{2.5}), including condensable PM, which is not controlled by the ESP. The impact of additional PM control achieved by the scrubber (for scenario 2) should be considered. The modeling results presented indicate fine PM has a limited impact on the modeled extinction (i.e., 9.51 percent and 18.6 percent of the modeled extinction for the baseline and Scenario 2 conditions, respectively, for Shining Rock). Also, the PM emissions are based on the most recent compliance test. These data likely represent the best ESP operating conditions, which may not be representative of ongoing emissions.

6. The State might consider giving a second look at the model inputs for PM emissions and the resulting visibility impacts for baseline conditions and scenarios No 2 and No 5 for two reasons. One reason to reconsider the PM inputs into the modeling is that the PM emissions are based on the most recent compliance test (as noted above in item number 5). These data likely represent the best ESP operating conditions, which may not be representative of ongoing emissions.

Another reason to possibly reconsider the PM data and modeled impacts is that there are ongoing discussions taking place between EPA and the pulp and paper industry (AF&PA/NCASI) related to measurement of PM_{2.5} emissions. The current use of EPA Method 202 by the industry appears to be underreporting PM_{2.5} emissions, specifically condensable PM_{2.5}. In some cases, the condensable PM is analyzed to determine the elemental composition and it is assumed that all of the sulfates found in the condensable PM are "artifacts" resulting from conversion of SO₂ to sulfates (i.e., to SO₃ and then to H₂SO₄). The reported condensable PM is "corrected" by subtracting the sulfate fraction from the total condensable PM emissions. This "correction" results in biasing the measured emissions low. It is not clear whether this type correction was done for the reported emissions used in this modeling analysis. The State may want to clarify how EPA Method 202 was used in the measurement of PM_{2.5} emissions. For more information on this method, go to:
<http://www.epa.gov/ttn/emc/methods/method202.html>.)

7. **Modeling performed at 1-km grid resolution** - Page 2-4 of the November 16, 2006 submission to NC DAQ notes that comments received from NC DAQ on March 7, 2006, related to the modeling protocol specific to the Blue Ridge Canton Mill states that "the 12-km screening approach should not be used. At a minimum, the 4-km CALMET data should be used and a refinement to 1-km may be necessary." This comment matches page 48 of the VISTAS Protocol document*, which says that source-receptor distances less than about 50 km may require grid resolution less than 1-km if complex terrain effects are likely to be important. More refined digital elevation model (DEM) data are also required. Complex terrain effects should be important in western North Carolina both within the Class 1 areas of concern and between the source and each of these areas. Although the BART control technology report omits the 12-km screening, it appears to report on only a 4-km grid resolution instead of the finer resolution recommended. It is not clear whether consideration was given to revising the modeling using a 1-km CALMET grid.
8. **Results tables specified in the VISTAS Protocol** - The VISTAS Protocol provides standard table formats for presenting modeling results. There should be a table showing number of days and number of receptors with impact greater than

* Visibility Improvement State and Tribal Association of the Southeast (VISTAS). Protocol for the Application of the CALPUFF Model for Analyses of Best Available Retrofit Technology (BART), December 22, 2005 (Revision 3.2 - 8/31/06).

0.5 dv for each Class 1 area, and for each year, number of days and number of receptors with impact greater than 1.0 dv for each Class 1 area for the entire 3-yr period, and the maximum 24-hr impact during the 3-yr period. These tables were provided in the October 2006 BART Exemption Modeling Report, but have not been included in the November 16, 2006, document. It is suggested that similar tables be included in the determination report. Also, documentation that addresses the development of the baseline modeling should be included in the determination report. This may be in the BART exemption modeling report. It is suggested that the complete October 2006 BART Exemption Modeling Report be included as an appendix to the determination report.

9. **Deciview Thresholds** - The document states in several places that "...the change in modeled visibility impact...is less than the 1 deciview threshold of human perception for changes in visibility." This statement implies that the controls are not considered to make enough of an improvement in visibility at the Class I areas identified in the report. We note, however, that there is no bright line for evaluating in the BART determination analysis the degree of visibility improvement that is considered significant enough to warrant BART controls. Rather, a State has flexibility in setting absolute thresholds and determining the weight and significance to be assigned to each BART factor. (See 70 FR 39170, 1st col., July 6, 2005.) Also, this statement does not recognize that a source may be *contributing* to visibility impairment at a Class I area.

Enclosure 3: Text Clarifications

Below are clarifications we wish to note on certain statements in the text. (The location of the text in the document is identified in parentheses.)

1. BACT Cost Effectiveness Comparisons (Section 1.2, P.1-1; cover letter, P.1)
The document makes the following statement: "As a comparison, costs from \$3,000 to \$5,000 per ton of emissions reduction are generally considered cost prohibitive for BACT evaluations." The Agency has not established cost effectiveness values considered cost prohibitive in regulation or policy. Also, these BACT cost effectiveness numbers may not be directly applicable for use in the BART cost analysis as BACT costs can apply to a new source adding on controls, whereas BART costs for retrofit technology may need to be weighed differently. The State will identify what costs are reasonable or not. Where data are available, we recommend use of a comparative approach for costs, i.e., compare cost effectiveness numbers to a similar facility which operates with controls under similar conditions. Another way of stating this is as follows.

If comparable emissions units are operating with controls, the owner of the BART-affected unit should show why control costs are prohibitive for the BART-affected unit, even though they are acceptable for similar controlled units in operation.

2. BART-Eligibility Descriptions (Section 2.2, P.2-2; Section 3.1, P. 3.1)
Potential to Emit (PTE) Thresholds: The PTE threshold provided for BART – eligible sources should be corrected to read, "...the potential to emit ~~more than~~ 250 tons per year or more..." (See 40 CFR 51.301, "Definitions," *Existing stationary facility*.)
3. Due date for Regional Haze SIPs (Section 2.2, P. 2-3)
The document identifies a due date for Regional Haze SIPs of January 2008. To clarify, the due date for Regional Haze SIPs specified in the Regional Haze regulations at 40 CFR 51.308 (b) is: "...no later than December 17, 2007."
4. Line-of-Sight (LOS)
 - (a) The document refers to a proposed LOS approach in several places and presents data for comparison on page 2-5. We recommend excluding LOS documentation since, as the report indicates, this specific approach is not appropriate for BART modeling purposes.
 - (b) The document provides selected definitions from 40 CFR 51. We wish to clarify that the definitions provided in Section 2.1 for *Line-of-Sight (LOS)* and *Just Noticeable Change* are not from the Definitions section of the Regional Haze regulations (40 CFR 51.301, "Definitions").
5. Permit Changes (Section 4.2, P.4-4)

The document asserts that the electrostatic precipitators (ESPs) on each RF exceed the Maximum Achievable Control Technology (MACT) standard for particulate matter (PM), and that this level of control is already required in the facility's Title V operating permit. The BART Guidelines say if the most stringent control available is adopted, it must be made federally enforceable for purposes of BART. Thus, the SIP and potentially the facility's permit must be modified to include a statement that these controls and operating conditions on the two recovery furnaces also serve to satisfy BART for PM.

6. References (Tables 4-2, 4-4, 4-6)

The EPA Cost Manual references for Tables 4-2, 4-4, and 4-6 are confusing as written, which made it difficult to find the appropriate citations. Chapter 1, December 1995, is cited in the EPA Cost Manual in these cost references. Since there are presently nine chapters labeled "Chapter 1" in the Cost Manual dated January 2002, we suggest that these references be clarified to include the relevant section and chapter title. This will enable reviewers to find the referenced portions of the document. In this case, the relevant items we suggest to include in these Cost Manual references are italicized as follows: "*EPA Air Pollution Control Cost Control Manual, sixth edition (January 2002), EPA 452-02-001, Section 5.2, Chapter 1, "Wet Scrubbers for Acid Gas," December 1995.*" (The current EPA Cost Manual is available at: <http://www.epa.gov/ttn/catcl/products.html#cccinfo>.)

7. Table 4-1 – "Summary of RBLC Database for SO2 Control Technologies"

It appears that the following four "RACT/BACT/LAER (RBLC)" Clearinghouse entries of facilities with SO2 controls on their RFs were either inadvertently omitted from Table 4-1 or slightly different search criteria may have been used. We used the following search criteria: default time span of 10 years back, Process Type: 30.211 "Kraft Recovery Furnaces/Boilers," Pollutant: "SOx". For completeness, we suggest including these entries if they were omitted in error. The following control descriptions are included here for your convenience:

- LA-0201, Weyerhaeuser Company, Red River Mill facility (Proper Boiler Design and Operation);
- LA-0207, International Paper Co, Mansfield Mill (Proper Design, Good Combustion Practices, Firing Low Sulfur Fuel, and a 10% Annual Capacity Factor for Fossil Fuels);
- MS-0078, Georgia Pacific Corporation, Monticello Mill (Combustion Control and Furnace Design); and
- NC-0108, International Paper, Roanoke Rapids Mill (Furnace Design and Combustion optimization).

Based on the RBLC search we performed, it also appears that certain RBLC entries with a "No Controls Feasible" label are not included in Table 4-1. We are unclear as to the reason for this. For completeness, we suggest that the table

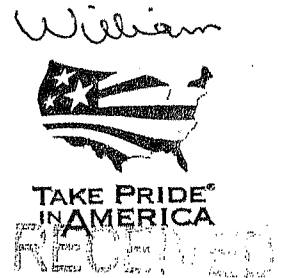
could either include all or exclude all facilities with a "No Controls Feasible" label.

8. Visibility Impact Thresholds (Section 4.1.5, P. 4-3)
Section 4.1.5 provides a summary of Step 5 of the BART Guidelines. The second paragraph of this section states: "If the net visibility improvement is less than the humanly perceptible change, then there is no need for the facility to implement the control technologies because the resulting visibility impacts would be negligible." The BART Guidelines do not make such an assertion. Rather, the Guidelines provide flexibility to the States with setting thresholds and weighing each of the BART factors. (See 70 FR 39170, 1st col., July 6, 2005.) All of the statutory factors should be used in the determination of whether or not BART controls are needed. Visibility improvement based on modeling results is only one of the factors that should be assessed in this decision.
9. 22nd highest values for the two worst-case years (Section 5.8, P. 5-7)
Page 5-7 of the document states that a spreadsheet was used to determine the 22nd highest values for the two worst-case years. The 98th percentile value for an individual year is the 8th highest value, so it is unclear why the report references the 22nd highest value. This appears to be a typographical error.



IN REPLY REFER TO:

United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225



February 7, 2007

N3615 (2350)

Ms. Sheila Holman
Division of Air Quality
1641 Mail Service Center
Raleigh, North Carolina 27699-1641

Re: Preliminary Comments and Questions on the ~~Blue~~ Blue Ridge Paper Products, "BART Control Technology Evaluation"

Dear Ms. Holman:

Exemption modeling showed that Blue Ridge Paper Products, Inc. (BRP) had visibility impacts greater than 0.5 deciview (dV) at the Great Smoky Mountains Class I area. BRP submitted a BART demonstration relating to five facilities within the paper mill, along with a paper entitled, "Retrofit Control Technology Assessment for NO_x, SO₂ and PM Emissions From Kraft Pulp and Paper Mill Unit Operations" by the National Council for Air and Stream Improvement, Inc. BRP contends that they already employ the "most stringent controls available" or that physical circumstances and low emission rates make retrofits prohibitively expensive. Thus, BRP requested that no additional control technologies be required to meet BART.

General Comments

On the last page of the Introduction, BRP states: "...the change in modeled visibility impact...is less than the 1 deciview threshold of human perception for changes in visibility...Therefore, BART is no further controls." Further, page 4-3 states, "If the net visibility improvement is less than the humanly perceptible change, then there is no need for the facility to implement the control technologies because the resulting visibility impacts would be negligible." We acknowledge that "visibility improvement that would result from controlling the emissions" is one of the factors in a BART analysis. However, the BART decision should not be based upon perceptibility. Because BRP's position is contrary to EPA Guidance, we ask that BRP show us the basis for this assertion.¹

¹ EPA states in the preamble to its BART Guidelines that, "Even though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contribution to haze may be significant relative to other source contributions in the Class I areas. Thus, we

Since there does not appear to be any dispute about the technical feasibility of scrubbing SO₂ from the recovery furnaces and reducing NO_x via improved combustion controls, BRP's cost benefit analyses (in terms of \$/ton removed and \$/dv visibility improvement) become the focus of our comments.

We have the following comments regarding Table 4-2 which presents a cost/benefit analysis for controlling SO₂ from the recovery furnaces:

- BRP refers to a vendor quote for the scrubber installation--that should be provided.
- While we believe it is legitimate to account for the costs of lost production and make up, we would like to see the actual calculations to support these very large figures.
- BRP refers to a 7/19/06 vendor e-mail for the installation of a new fan and ductwork—that should be provided.
- The reference for the cost of new switch gear installation is missing and should be provided.
- If waste caustic is available from the bleach plant—if there is one—it could be used as the scrubbing reagent, thus reducing reagent and disposal costs—this should be investigated.
- The Capital Recovery Factor is inflated. The OAQPS Control Cost Manual recommends 7% interest over a 15-year life, not the 15% over ten years used by BRP.
- BRP should document the 90% scrubber efficiency assumption—it seems low.

We have the following comments regarding Table 4-4 which presents a cost/benefit analysis for controlling NO_x from the recovery furnaces:

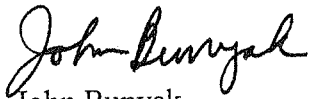
- BRP should provide documentation to support its cost estimates.
- While we believe it is legitimate to account for the costs of lost production and make up, those costs should not be included in the base for estimating Indirect Annual Costs.
- The Capital Recovery Factor is inflated. The OAQPS Control Cost Manual recommends 7% interest over a 15-year life, not the 15% over ten years used by BRP.
- BRP should document the 40% control efficiency assumption.

Basically, we are concerned that BRP may have overestimated costs and underestimated benefits.

disagree that the degree of impairment should be contingent upon perceptibility. Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment."

Please feel free to contact Don Shepherd (303-969-2075) of my staff if you have any questions.

Sincerely,

A handwritten signature in cursive script that reads "John Bunyak".

John Bunyak
Chief, Policy, Planning and Permit Review Branch



February 28, 2007

Mr. Don Van der Vaart, PE, PhD
North Carolina Department of Environment and Natural Resources
Division of Air Quality
1641 Mail Service Center
Raleigh, North Carolina 27699

**Reference: Blue Ridge Paper Products, LLC
Canton, North Carolina
BART Control Technology Evaluation**

Dear Don:

On behalf of Blue Ridge Paper Products, LLC (Blue Ridge), URS Corporation (URS) is pleased to submit the following responses to comments made by interested parties reviewing the Best Available Retrofit Technology (BART) Control Technology Evaluation submitted to the North Carolina Division of Air Quality (NCDAQ) on November 16, 2006.

To facilitate review of our responses, we have included the commenter's statement followed by our response in *italics*. Comments addressed in this correspondence include the following:

1. January 31, 2007 letter from Kay T. Prince of the United States Environmental Protection Agency.
2. February 7, 2007 letter from John Bunyak of the National Park Service, Air Resources Division.

Once you have had the opportunity to review our responses, please do not hesitate to contact me at (919) 461-1520 with any additional questions or comments.

Sincerely,

Randall K. Taylor, CCM, QEP
Air Program Manager

CC: Paul Dickens, Blue Ridge

URS Corporation
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Tel: 919.461.1100
Fax: 919.461.1415

Enclosure No. 1

1. EPA Comment - Pollution Prevention (P2) Options

When identifying all available retrofit control technologies, the "Guidelines for BART Determinations under the Regional Haze Rule" (BART Guidelines) clarify that consideration should be given not only to add-on controls but also improvement in the performance of existing controls and P2. The analysis does not discuss the facility's evaluation of any P2 options for the five BART-eligible units, with the exception of installation of quaternary air on each recovery furnace (RF).

Blue Ridge Paper Response

The BART-affected units at Blue Ridge Paper Products Inc. (Blue Ridge) are Recovery Furnaces No. 10 and 11, Smelt Dissolving Tanks No. 10 and 11, and the Black Liquor Oxidation System. It is important to note that the very nature of these units is pollution prevention. The Kraft pulping process seeks to maximize chemical and energy recovery from the pulping process. By maximizing the recovery of color materials and lignin present in the wood fiber, the facility is minimizing the amount of fossil fuel combustion required to meet the steam and energy demands of the mill.

Furthermore, in conducting research on the control technologies available for the BART-affected units, Blue Ridge relied on information compiled by the National Council for Air and Stream Improvement (NCASI) through Corporate Correspondents Memorandum CC 06-014 entitled "Retrofit Control Technology Assessment for NO_x, SO₂, and PM Emissions from Kraft Pulp and Paper Mill Unit Operations." As the environmental control reference organization for the pulp and paper manufacturers, NCASI follows the industry closely and is aware of the control measures that are currently employed. The technologies identified in this memorandum were evaluated for applicability none of which included pollution prevention technologies.

The comments provided by EPA also focused on information available in "Assessment of Control Options for BART Eligible Sources," prepared by NESCAUM, for the Mid-Atlantic/Northeast Visibility Union Regional Planning Organization. Review of this document only identified one additional control option for the reduction of sulfur dioxide from the Recovery Furnaces. That option is to reduce liquor sulfidity in the black liquor solids. Sulfidity is the ratio of Na₂S to the active alkali, where active alkali is the sum of sodium hydroxide and Na₂S. The Blue Ridge recovery cycle has been balanced with a target sulfidity of 24-26%. Reducing the liquor sulfidity can adversely affect pulp quality and the cooking reaction rate. Therefore, reducing liquor sulfidity is not a viable option for the Blue Ridge Mill.

2. EPA Comment - Process Changes to Reduce Formation of Emissions from RFs

Although Table 4-1 indicates that several Kraft pulp and paper mills utilize good combustion control practices to minimize sulfur dioxide (SO₂) emissions from their RFs, there is no discussion of what options may exist for making process changes, such as improved furnace design and operation, to limit the formation of SO₂ in each RF. An effective approach to minimizing the formation of SO₂ in the RFs would be to practice high dry solids firing combined with a modern air system to promote efficient mixing. Examples of process changes which have been demonstrated are identified in section 5.3.1 of "Assessment of Control Options for BART Eligible Sources," prepared by NESCAUM, for the Mid-Atlantic/Northeast Visibility Union Regional Planning Organization:

<http://www.nescaum.org/documents/bart-resource-guide/>. These examples include optimizing liquor and combustion air properties and firing patterns to maintain uniform temperatures in the lower part of the RF in order to reduce SO₂ emissions, and reducing liquor sulfidity to reduce SO₂ emissions from the RFs.

Blue Ridge Paper Response

The referenced document indicates that SO₂ emissions from a recovery furnace are dependent on the following: sulfidity, heating value, solids content, combustion air and liquor firing patterns, furnace design features, furnace load, auxiliary fuel use, and stack gas oxygen content. As mentioned in the response to comment No. 1, the Blue Ridge recovery cycle has been balanced with a target sulfidity of 24-26%. Reducing the liquor sulfidity can adversely affect pulp quality and the cooking reaction rate. Therefore, reducing liquor sulfidity is not a viable option for the Blue Ridge Mill.

The recovery furnace design at Blue Ridge includes direct contact evaporators (DCE) preceded by Black Liquor Oxidation (BLOX) for recovery furnace odor control. In this configuration, the design dry solids firing rate in the recovery furnace is 60 to 65 percent. There is a about a 5 percent loss of Btu heating value in the black liquor due to BLOX. Newer and larger capacity recovery furnaces use non-contact evaporators (NCE), do not have the BLOX process and have a design dry solids firing rate of 70 to 75 percent. These newer NCE recovery furnaces include quaternary air and may have a lower NO_x emission rate than the DCE recovery furnaces at Blue Ridge Paper. Conversion from DCE to NCE involves an entire furnace rebuild and reconfiguration is not a practical upgrade option. For the recovery furnace configuration at Blue Ridge Paper, the design dry solids firing rate is optimized.

Modifications that would change the firing pattern and maintain uniform temperatures in the lower part of the recovery furnace are very similar to the changes proposed for the installation of quaternary air and new liquor guns for the reduction of NOx emissions. Total capital investment for the modification was in excess of thirty million dollars and the reduction in sulfur dioxide emissions from the change would be minimal. The majority of sulfur entering a recovery furnace leaves with the smelt.

3. EPA Comment: Control Option Alternatives

The document states that installation of add-on SO₂ controls on the RFs results in lower stack heights and a higher modeled delta deciview (dv) than current conditions due to decreased dispersion associated with scrubber' exhaust characteristics. (Executive Summary) We believe this may be due to the effects of cooling the exhaust stream. The analysis does not discuss whether good engineering practice (GEP) was considered in the development of the new stack height for this SO₂ control.

Blue Ridge Paper Response

As stated in the document, the increased delta deciview from the installation of a scrubber on the recovery furnace exhaust is due to a cooler plume. A GEP analysis was performed for the facility including the modeled scrubber stack and all stack heights included in the modeling analyses meet the GEP modeling requirements.

4. EPA Comment - Lost Production Costs

There is no indication of whether the facility considered ways to mitigate costs attributed to "Lost Production" listed in Table 4-2 (pulp purchase of \$5,390,000 plus \$975,843 for lost power generation per RF) and Table 4-4 (\$11,550,000 for pulp purchase for 30 days downtime per RF). For example, the effects on costs in Tables 4-2 and 4-4 if potential controls were installed during an already planned plant shutdown for maintenance, or when one of the RFs is off-line, should be addressed. Also, it is unclear why one month is needed for each RF retrofit to install a quaternary air system, which results in significant lost production costs of purchased pulp in Table 4-4.

Blue Ridge Paper Response

The recovery furnaces at Blue Ridge are scheduled for a 5-day shutdown once per year. Additionally, each unit undergoes a one-day shutdown every 15 to 20 weeks. Each of the recovery furnaces routinely operates at maximum capacity to meet the production demands of the mill; therefore, there are not significant blocks of time to conduct the modification when one unit is off-line.

The installation of quaternary air would also require installation of new liquor guns to improve fuel bed distribution and the furnaces must also undergo a complete rebalancing of the air system. The air system is currently run by a forced-draft steam turbine fan that was originally installed with the recovery furnace. This technology will require additional time to obtain optimum air flows. Furthermore, all of the modifications must be completed when the recovery furnace is shut-down, unlike the installation of a scrubber system, where many of the components can be fabricated prior to shutting down the recovery furnace.

The recovery furnace is the heart of the Kraft pulping process. The black liquor recovery process is continuous and the storage capacity to continue pulp operations during a recovery furnace outage is very limited – one day at most. When a recovery furnace goes down, black liquor is not recovered and the pulping process stops. This is the reason that during an extended recovery furnace outage, Kraft pulp is not manufactured. To keep paper machines running, dry furnish Kraft pulp must be purchased from outside sources, at a significant cost premium compared to slush pulp manufactured on-site.

EPA Comment

When major work is done at a pulp and paper mill, the mill can often increase production significantly prior to and following the shutdown to offset any lost production. It is not clear whether the facility considered this possibility and its effects on the lost production costs.

Blue Ridge Paper Response

As previously mentioned, the recovery furnaces at Blue Ridge are consistently operated at maximum capacity to meet current production demands. Therefore, it would not be possible to operate the units at an increased rate prior to and following the planned shutdown.

Furthermore, as mentioned in Comment No. 3, the available capacity for black liquor storage is limited to a maximum of one-day, thereby limiting the potential operating scenarios.

EPA Comment

To minimize lost power generation costs listed in Table 4-2, it is not clear whether the facility considered achieving some additional power generation from its power boilers during the retrofit period to offset the losses. The mill has five power boilers and generally a pulp and paper mill with multiple power boilers does not operate all the boilers at maximum capacity at the same time.

Blue Ridge Paper Response

When a recovery furnace is down, approximately 300,000 lbs per hour of lost steam production from burning black liquor solids must be supplemented by burning additional coal in the mills power boilers and by buying additional power from the commercial grid. Blue Ridge generates most, but not all, of its electrical power needs. When steam production is down during a recovery furnace outage, the mix of mill generated and purchased power changes. Steam production is shifted from electrical power generation to the paper machines and more electricity is purchased from the commercial grid. The cost of lost power generation in the cost estimates represents the additional cost to supply the energy needs of the Canton Mill paper machines when free steam energy from burning black liquor solids is not available due to recovery furnace outage.

5. EPA Comment - Contingency Costs in Table 4-2

In Table 4-2, the contingency factor of 15 percent should be justified. It is our understanding that a factor no higher than 10 percent would be considered acceptable for wet scrubber installation on a RF at a pulp and

paper mill, and would be consistent with standard industry practice. Also, since this is a "turnkey" installation, it is unclear why such a high contingency factor is projected. Since no distinct retrofit factor is identified, it is possible that the facility may have merged the retrofit factor with the contingency factor, resulting in the 15 percent contingency factor used in Table 4-2. The *EPA Air Pollution Control Cost Manual* (Cost Manual), EPA/452/B-02-001, January 2002, distinguishes between the contingency and retrofit factors and recommends keeping them separate as follows. A retrofit factor should be reserved for those items directly related to the demolition, fabrication, and installation of the control system, and should not be double-counted again as part of a contingency factor. In this case, the additional ductwork, new stack, fan, and switch gear should be assigned to the retrofit factor since they are a necessary part of installing this control on an existing unit. A contingency factor should be applied to only those items that could incur a reasonable but unanticipated cost increase (i.e., outside of the contractor's control), and are not directly related to the retrofit factor elements just described. (See pages 2-28 to 2-30 in subsection 2.5.4.2 of Chapter 2, Cost Estimation: Concepts and Methodology," (dated January 2002) in Section 1 of the Cost Manual.)

Blue Ridge Paper Response

The contingency factor presented in Table 4-2 did include the retrofit factor. Please refer to Attachment 1 of this correspondence for an updated calculation of costs associated with the installation of a wet scrubber on a single recovery furnace. As stated in EPA's Cost Control Manual:

*“Probably the **most subjective part** of a cost estimate occurs when the **control system is to be installed on an existing facility**. Unless the original designers had the foresight to include additional floor space and room between components for new equipment, the installation of retrofitted pollution control devices can impose an additional expense to “shoe-horn” the equipment into the right locations.”*

“The magnitude of the retrofit factor varies across the kinds of estimates made as well as across the spectrum of control devices. At the study level, analysts do not have sufficient information to fully assess the potential hidden costs of an installation. At this level, a retrofit factor of as much as 50 percent can be justified.”

EPA Comment

The contingency factor calculations in Table 4-2 are not based on the correct line item costs and need to be redone. The factor was applied to the scrubber "installation cost," additional ductwork, new stack, fan, and switch gear, and lost power generation. This is incorrect for two reasons. First, the "installation cost" listed for the wet scrubber appears to also include the cost

of the equipment. The contingency factor should be applied to the purchased equipment costs. However, installation costs are not to be included in contingency factor calculations. This should be corrected.

The second reason the calculations are incorrectly applied is that the "14 days lost power generation" cost of \$975,843 should not be included in the "contingency" cost calculations. The Cost Manual describes contingencies as a category that covers unforeseen costs that may arise, such as delays encountered in start-up and increases in field labor costs. (See page 2-5, of Chapter 2, "Cost Estimation: Concepts and Methodology," (dated January 2002) in Section 1 of the Cost Manual.) The lost power generation cost in Table 4-2 refers to power that cannot be produced during the 14-day retrofit period for each RF, which is a planned event, not an unforeseen cost. We note that lost production in terms of pulp purchase correctly does not appear to be included in the contingency cost calculations.

Blue Ridge Paper Response

The terminology used in line one of the calculations was revised to make it clearer. The cost shown is indeed the purchased equipment cost. In responding to these comments, vendors were contacted to provide additional information for the exact situation at Blue Ridge. All of the correspondence is included in Attachment 1 to this letter and the costs are outlined in the revised Table 4-2. Furthermore, the contingency percentage was not applied to purchased electrical costs in the revised calculations.

EPA Comment - RF Wet Scrubber Cost Considerations

Table 4-2 describes costs with wet scrubber installation on one of the RFs. Given the relatively high nature of costs for the modifications to existing ductwork and installation of a new stack, fan, and switch gear (totaling to \$11,945,605), consideration should be given to other, more cost effective options. For example, the feasibility and cost effectiveness of moving the road or other buildings to allow closer location of the wet scrubbers and avoid extensive ductwork could be considered.

Blue Ridge Paper Response

To assist in understanding the unique situation at Blue Ridge, we have included an aerial photograph of the site. As you will note, the mill is located in the heavy industrial area within the Town of Canton. Mill property is extremely limited and the options proposed in the comments are not feasible. The roads cannot be moved due to fire regulations and there are no buildings to be moved.



Figure No. 1 – Overview of the Canton Mill

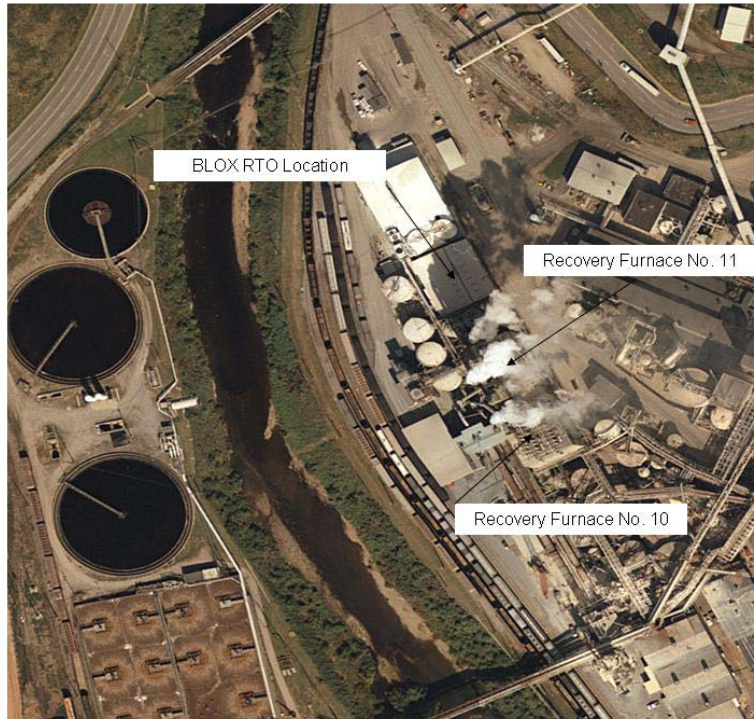


Figure No. 2 – Overview of Canton Mill Recovery Furnaces

EPA Comment

It would be helpful to have more information on the design of the wet scrubber analyzed. We are aware of at least one kraft pulp mill (i.e., the James River Camas Mill in Washington State) that has installed a cross-flow, packed bed scrubber following the RF electrostatic precipitator (ESP) as part of an energy recovery system. At that mill, caustic (sodium hydroxide or NaOH) is added to the scrubber liquid and the mill has claimed SO₂ reductions as a result. It is not clear whether the facility has considered installing a similar system.

Blue Ridge Paper Response

There are many scrubber configurations commercially available. We have evaluated the MECS Reverse Pulse Jet system. While the cost for the scrubber itself is significant, the largest cost contribution is from the installation of ductwork to route the exhaust to the unit and modifications to the fan and switch gear. These costs would be approximately the same no matter the scrubber design.

EPA Comment

There is no discussion indicating whether the facility considered use of caustic as the scrubbing reagent instead of limestone. Kraft pulp mills have a relatively inexpensive supply of caustic available since it is used in the cooking liquor, which can make caustic more economical than limestone. Also, the use of caustic eliminates the material handling and space requirements associated with lime or limestone systems. Lime and limestone processes produce a sludge which requires dewatering and landfilling. Wet caustic processes produce a neutral pH solution which can be pumped to the existing mill wastewater treatment system for disposal. Thus, the estimated annual costs would be greatly reduced by using a caustic scrubber instead.

Blue Ridge Paper Response

Annual reagent costs for the use of limestone in the scrubber have been estimated at less than \$10,000 dollars per year and landfill disposal costs are also less than \$10,000 dollars per year. As stated previously, the capital investment required for the installation of a scrubber is the primary driver making the option economically infeasible. However, to address concerns raised in the comments, the revised scrubber cost estimate has been estimated assuming a caustic solution is used in the unit.

However, all of the caustic required for the scrubber must be purchased and a vessel to store the material must be installed. The Blue Ridge mill is caustic limited due to lime kilns that are undersized. The mill already buys caustic for make-up in the white liquor system.

EPA Comment

We suggest that the State closely evaluate the electricity costs for the RF scrubber. For example, the basis for the 746 kilowatt-hours used in Table 4-2 should be discussed. Other considerations should include the assumed pressure drop of the scrubber, and what portion of the electricity costs are associated with the use of limestone rather than caustic (e.g., limestone preparation and slurry mix system, gypsum filter system, etc.).

Blue Ridge Paper Response

The fan rating is estimated at 1,000 hp. Mill specific electricity costs are \$319.00 per hp-yr.

7. EPA Comment - RF Quaternary Air System Cost Considerations

The capital cost estimate of \$9 million (includes quaternary air and new liquor guns for both RFs) cited on page 4-7 and detailed per RF in Table 4-4

seems extremely high. In 2001, the American Forest and Paper Association (AF&PA) commissioned BE&K Engineering to develop emissions control cost estimates for a variety of scenarios at pulp and paper mills, including the addition of a quaternary air system for reducing NOx emissions from a RF. The model RF was larger than the RFs at Blue Ridge. Based on the AF&PA analysis, the capital cost for the quaternary air system was \$624,000 per furnace. Disregarding differences in size and base years, the total cost would be approximately \$1.2 million for two RFs, which is considerably less than the \$9 million quoted on page 4-7. It would be helpful if Blue Ridge could provide an estimate just for the addition of the quaternary air system, omitting the costs of the new liquor guns, to provide for a better comparison of costs.

Blue Ridge Paper Response

The cost estimate for the installation of quaternary air on the recovery furnaces is an estimate provided by an outside vendor. In order to achieve the discussed NOx reductions, quaternary air alone would not be sufficient. The liquor guns must also be replaced to improve fuel bed distribution. Furthermore, the furnaces must also undergo a complete rebalancing of the air system after the modification. The air system is currently run by a forced-draft steam turbine fan that was originally installed with the recovery furnace. This older technology will be more costly to balance than current systems.

The original Kraft pulp recovery furnace installations at Blue Ridge had 2-stage combustion. These are medium-sized furnaces by today's standards, but at the time of installation in the 1960s and early 1970s these were large, state of art units. The furnaces were upgraded for BLOX and for tertiary air in the 1980s. The tertiary air upgrade was complex and took most of the space available for any future upgrade to combustion staging. Champion International, the predecessor company to Blue Ridge, studied various options for combustion control improvements to the Canton Mill recovery furnaces in the 1980s. The cost of various upgrade options were estimated including quaternary air and alternative configuration black liquor fuel guns. However, the upgrade to tertiary air and BLOX that were undertaken were the only practical modifications for the size and configuration of these furnaces.

In preparation for BART, Blue Ridge worked with Jansen Technologies, a recovery furnace combustion consulting firm, to develop order of magnitude cost estimates for addition of quaternary air and alternative configuration black liquor fuel guns. The available Champion International engineering evaluations from the 1980s were reviewed and the previous conclusions were validated - addition of quaternary air is not a simple add-on as suggested by EPA comments. Addition of quaternary air to the existing Blue Ridge recovery furnaces will require removing all the existing combustion

air staging equipment, modifying and moving the existing combustion air ports in the furnace (all ASME code vessel welding) and reinstallation of the existing along with new combustion air ductwork and fans. New combustion air controls are necessary. The design considerations for changing black liquor fuel guns are similar. This is not a simple swap out of equipment. Alternative black liquor fuel guns will require a complete reworking of the recovery furnaces above the smelt bed. New fuel gun combustion controls are also required.

The order of magnitude cost of \$4.5 million each (\$9 million total) for retrofit of the Blue Ridge recovery furnaces to quaternary air and alternative fuel guns is based on the above considerations developed by Blue Ridge in consultation with Jansen Technologies. Please note that this value is only the construction portion of the cost, lost production and lost power generation are additional costs to obtain total capital investment. The time estimate for retrofit of one month per recovery furnace is also based on this engineering review. The retrofit is not a simple add-on or swap out of equipment. Retrofit will require a major reworking of the entire furnace combustion air and liquor firing equipment and controls.

8. EPA Comment - Supporting Documentation for Cost Analyses

To aid review of the document, we suggest that the vendor quotes, data estimates, and relevant portions of the presentation identified in the cost references [1], [6], [7] in Tables 4-2 be included in this document. Also, it is unclear where the e-mail described in Reference 1 of Table 4-2 is located in the documentation so we were unable to review this reference.

Blue Ridge Paper Response

Due to the limited time we had to prepare the BART evaluation, the best information available at the time was used preparing the original cost analysis. Attachment 1 to this letter contains an updated Table 4-2 with more detailed information and copies of more recent vendor correspondence.

EPA Comment

Reference 7 of Table 4-2 indicates that costs for wet scrubber installation are based on a vendor quote for an "original recovery furnace," which does not appear to be either of the RFs subject to this BART analysis. Although the facility adapted the cost estimate to the size of the No. 10 RF, we question why the facility did not seek a vendor quote for wet scrubber installation specific to the RFs subject to this BART analysis (i.e., No. 10 and No. 11). We recommend that a copy of the quote be included in the documentation to provide information such as what year the quote for the

original RF was received.

Blue Ridge Paper Response

Because of time constraints in the preparation of the original document, it was not possible to obtain a vendor quote for the specific installation at Blue Ridge. However, in responding to these comments we have contacted vendors and included their correspondence in Attachment 1 to this letter.

EPA Comment

Reference 7 of Table 4-2 also states that, "Cost was escalated using EPA's 0.6 rule ... " The "0.6 rule" referenced is to be used for a rough estimate calculation of costs only and should not be relied upon for this BART analysis to estimate installation costs of the wet scrubber. Also, we are not aware that the "0.6 rule" is part of an EPA document. However, the book, *Plant Design and Economics for Chemical Engineers* by Peter and Timmerhaus (Fifth Edition) does discuss this "rule of thumb" and calls it the "six-tenths-factor" rule. (Peters, Max S., Timmerhaus, Klaus and West, Ronald. *Plant Design and Economics for Chemical Engineers*, Fifth Edition, McGraw-Hill, 2002, p. 169.)

Blue Ridge Paper Response

While the six-tenths rule may not be correctly described as an "EPA Rule," the concept is frequently used in EPA documents. Furthermore, the Cost Control Manual states the following:

"Study-level estimates are acceptable for regulatory development because they represent a compromise between the less accurate order-of-magnitude and the more accurate estimate types."

A "study" level estimate is defined as a cost estimate with an uncertainty of +/- 30%. Therefore, it is Blue Ridge's position that without having site-specific design data which would be costly to obtain, the use of the six-tenths factor to adjust costs is appropriate since the purpose of this effort is regulatory applicability.

9. EPA Comment - Capital Recovery Factor (CRF) Calculations

The facility should justify its capital recovery cost assumptions of an equipment life of 10 years with an interest rate of 15 percent listed under "Indirect Annual Costs" in Tables 4-2, 4-4, and 4-6. For capital recovery costs on wet scrubbers for acid gas, the EPA Cost Manual and EPA's *Technical Support Document: Chemical Recovery Combustion Sources at Kraft and Soda Pulp Mills* (EPA-453/R-96-012, October 1996) presume a CRF based on a 15- year control equipment life and an interest rate of seven percent. Note that changing the assumptions about equipment life and interest rates to this presumptive value significantly decreases the annualized cost estimates.

Blue Ridge Paper Response

Please refer to the following excerpt from page 2-13 of EPA's *Cost Control Manual*:

*"Analysts use the interest rate to estimate the time value of money. It can be thought of as a **return on investment or the cost of borrowing**. The interest rate employed in this Manual differs from that used in non-governmental financial analyses. It represents a **social interest rate** established by the Office of Management and Budget (OMB) for the comparison of public policy issues.*

OMB sets the social interest rate for governmental analyses and it is currently set at seven percent.

*However, **the social rate of interest is not appropriate for industry**. When choosing between alternative air pollution control devices, the industrial planner must not only take into consideration the costs of each device, they must also understand how the **cost of each device fits into the financial structure of their business**. Furthermore, a number of air regulations allow sources of pollution to petition for extensions on deadlines, variances from the regulation, or exemption from installing control devices, based upon the economic impact that equipment would have upon the source. In these cases, **the source may find it useful to apply their own interest rate to the calculation of control costs**. Common interest rates used by industry and accepted by the EPA for source petitions include the **business' current borrowing rate, the current prime rate, and other acceptable industrial rates of return.**"*

The application of a 7% interest rate is not appropriate for this analysis, and furthermore, the EPA Cost Control Manual does not require the use of 7% as discussed above. The 15% rate is being used to account for the project costs as well as for the lost capital available for

funding other projects that could have positive return on investment at the mill. The recovery furnaces are currently more than 40 years old, assuming a useful life of 15 years would not be appropriate for this application. Therefore, all calculations have been completed using 10 years.

Enclosure 2

1. EPA Comment

Table 5-1 indicates a 31.25-meter decrease in the stack heights for the No. 10 and 11 RFs' stack for Scenarios 2 and 5. It is unclear why a decrease in stack height is required or if this is a typographical error. Also, the analysis does not discuss whether GEP was considered in the development of the new stack height for this SO₂ control. According to Table 5-1, the modeled location of the stacks has not changed from the current location. Table 5-4 indicates that the maximum visibility impact has shifted slightly to another geographical location in the Shining Rock and Great Smoky Mountain Class I areas. With decreased SO₂ emissions from installation of the scrubber, the expected result is that the visibility impact should also decrease. The analysis should provide more discussion on how and where the visibility increases occurred in the Class I areas in addition to providing the maximum delta visibility impact and explain why a decrease in stack heights is necessary.

Blue Ridge Paper Response

The new scrubber location proposed is approximately 300 feet from the current recovery furnace exhaust location. Since the CALPUFF model is evaluating long-range transport effects, moving the stack 300 feet on the property would have a negligible impact on long-range transport. The stack height selected is based on the design of the new RTO stack height and the cost to install this stack was used in the cost analysis for the scrubber. The cost to install the new stack at the modeled stack height is \$8,147,189. The cost to install a 300 foot stack would be \$15,750,000. This would further decrease the cost effectiveness of the scrubber from \$12,177 per ton to \$15,372 per ton.

It should be noted that while SO₂ emissions from the recovery furnaces are lower after the installation of a scrubber, the resulting exhaust plume is emitted at a much lower temperature, thereby causing a reduction in dispersion.

2. EPA Comment

The NO_x emissions used in the baseline (i.e., Scenario 1) modeling was based on a February 1999 stack test. There is no discussion of why data from this year was used to the exclusion of data from other years. Such discussion should include such items as stack test data availability from other years and how this ensures that the maximum 24-hr emission rate for the 2001-2003 period was developed. We encourage the State to review these data to ensure the assumptions supporting the emission rates are correct and the supporting documentation is submitted.

Blue Ridge Paper Response

The best available data regarding emissions of NOx from a recovery furnace were used in the analysis. Stack testing was only conducted at the facility during 1999 and no subsequent testing has been required. This emission factor is the same value as is used in the preparation of the Annual Air Emissions Inventory.

The other known source of NOx emissions data from recovery furnaces comes from NCASI Technical Bulletin No. 884. However, the test data presented in this document is the result of only one test run and is lower than the value used in the modeling. Therefore, this data was excluded from the BART evaluation.

3. EPA Comment

A vendor guarantee was used to set the emission rate for the black liquor oxidation system (BLOX) regenerative thermal oxidizer (RTO) provided in Table 5-2 (reference 3). We suggest that the referenced guarantee be included in the document and recommend that the State carefully evaluate this rate in conjunction with the specified operating parameters to ensure appropriate values are being used in the BART modeling.

Blue Ridge Paper Response

Blue Ridge Paper submitted an application on June 17, 2004 to request approval of an alternate compliance approach to that required in 40 CFR Subpart S for the high-volume, low-concentration (HVLC) sources (referred to as MACT I, Phase 2). This alternate compliance approach was approved by EPA on March 10, 2005. All the referenced vendor guarantee information was submitted along with the Equivalency-by-Permit application. This is located in the NCDAQ files, however, Blue Ridge could provide another copy if needed.

4. EPA Comment

It may appear that the visibility improvements from the various control scenarios assessed do not indicate a desired level of benefit at two of the five Class I areas, but the other three Class I areas being affected by the facility could also be considered in the determination.

Blue Ridge Paper Response

There are five (5) Class I areas within 300 km of the mill: Shining Rock, Linville Gorge, Cohutta, Joyce Kilmer/Slickrock, and the Great Smoky Mountains. Shining Rock is located approximately 11 kilometers south of

the mill, the Great Smoky Mountains National Park is 22 kilometers west, Linville Gorge is 89 kilometers northeast, Joyce Kilmer/Slickrock is 99 kilometers west southwest, and Cohutta is located approximately 161 kilometers southwest of the mill.

The BART exemption modeling submitted to the NCDAQ on April 27, 2006 indicated that modeled values would be greater than 0.5 dv at the Great Smoky Mountains and Shining Rock. Modeled values were less than 0.5 dv at the other Class I areas and are deemed insignificant based on EPA's guidance regarding single source contribution values. Given that there are five control option scenarios that required modeling for the BART evaluation, modeling was performed for the two Class I areas where previous modeling indicated values greater than 0.5 dv.

5. EPA Comment

Addition of a wet scrubber should also reduce fine particulate matter (PM_{2.5}), including condensable PM, which is not controlled by the ESP. The impact of additional PM control achieved by the scrubber (for scenario 2) should be considered. The modeling results presented indicate fine PM has a limited impact on the modeled extinction (i.e., 9.51 percent and 18.6 percent of the modeled extinction for the baseline and Scenario 2 conditions, respectively, for Shining Rock). Also, the PM emissions are based on the most recent compliance test. These data likely represent the best ESP operating conditions, which may not be representative of ongoing emissions.

Blue Ridge Paper Response

Installation of a wet scrubber on the recovery furnaces would follow the electrostatic precipitators already installed on the units. Appendix Y to 40 CFR 51 states the following:

“If you find that a BART source has controls already in place which are the most stringent controls available (note that this means that all possible improvements to any control devices have been made), then it is not necessary to comprehensively complete each following step of the BART analysis in this section. As long as these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, you may skip the remaining analyses in this section, including the visibility analysis in step 5.”

Recent stack testing performed to demonstrate compliance with MACT II showed emissions of 0.004 gr/dscf at 8% O₂ for No. 10 Recovery Furnace and 0.007 gr/dscf at 8% O₂ for No. 11 Recovery Furnace. The purpose of the stack test was to demonstrate compliance with MACT emission limits at a level that represents at least 90 percent of capacity. Therefore, during the test, the mill was operated at high capacity and Blue Ridge continues to

operate the recovery furnaces under the conditions during the test to ensure on-going compliance.

Therefore, potential retrofit control technologies for particulate matter emissions from the recovery furnaces was not further evaluated since the units are already equipped with the most stringent controls and the operation of these controls is required by the facility's Title V Operating Permit.

Although the installation of a scrubber would provide some additional particulate control, the loading to the device would be minimal as shown by the test results provided above, therefore, the additional particulate control from the scrubber would be minimal.

6. EPA Comment

The State might consider giving a second look at the model inputs for PM emissions and the resulting visibility impacts for baseline conditions and scenarios No 2 and No 5 for two reasons. One reason to reconsider the PM inputs into the modeling is that the PM emissions are based on the most recent compliance test (as noted above in item number 5). These data likely represent the best ESP operating conditions, which may not be representative of ongoing emissions.

Another reason to possibly reconsider the PM data and modeled impacts is that there are ongoing discussions taking place between EP A and the pulp and paper industry (AF&P NNCASI) related to measurement of PM_{2.5} emissions. The current use of EPA Method 202 by the industry appears to be underreporting PM_{2.5} emissions, specifically condensable PM_{2.5}. In some cases, the condensable PM is analyzed to determine the elemental composition and it is assumed that all of the sulfates found in the condensable PM are "artifacts" resulting from conversion of SO₂ to sulfates (i.e., to SO₃ and then to H₂SO₄). The reported condensable PM is "corrected" by subtracting the sulfate fraction from the total condensable PM emissions. This "correction" results in biasing the measured emissions low. It is not clear whether this type correction was done for the reported emissions used in this modeling analysis. The State may want to clarify how EP A Method 202 was used in the measurement of PM_{2.5} emissions. For more information on this method, go to: <http://www.epa.gov/ttn/emc/methods/method202.html>.

Blue Ridge Paper Response

The particulate test values used for the modeling analyses are in accordance with North Carolina Division of Air Quality guidance for Annual Air Emissions reporting purposes.

7. EPA Comment

Modeling performed at 1-km grid resolution - Page 2-4 of the November 16, 2006 submission to NC DAQ notes that comments received from NC DAQ on March 7, 2006, related to the modeling protocol specific to the Blue Ridge Canton Mill 'states that "the 12-km screening approach should not be used. At a minimum, the 4-km CALMET data should be used and a refinement to 1-km may be necessary." This comment matches page 48 of the VISTAS Protocol document, which says that source-receptor distances less than about 50 km may require grid resolution less than 1-km if complex terrain effects are likely to be important. More refined digital elevation model (DEM) data are also required. Complex terrain effects should be important in western North Carolina both within the Class 1 areas of concern and between the source and each of these areas. Although the BART control technology report omits the 12-km screening, it appears to report on only a 4-km grid resolution instead of the finer resolution recommended. It is not clear whether consideration was given to revising the modeling using a 1-km CALMET grid.

Blue Ridge Paper Response

The BART modeling was performed in accordance with a modeling protocol approved by the North Carolina Division of Air Quality.

8. EPA Comment

Results tables specified in the VISTAS Protocol - The VISTAS Protocol provides standard table formats for presenting modeling results. There should be a table showing number of days and number of receptors with impact greater than 0.5 dv for each Class 1 area, and for each year, number of days and number of receptors with impact greater than 1.0 dv for each Class 1 area for the entire 3-yr period, and the maximum 24-hr impact during the 3-yr period. These tables were provided in the October 2006 BART Exemption Modeling Report, but have not been included in the November 16, 2006, document. It is suggested that similar tables be included in the determination report. Also, documentation that addresses the development of the baseline modeling should be included in the determination report. This may be in the BART exemption modeling report. It is suggested that the complete October 2006 BART Exemption Modeling Report be included as an appendix to the determination report.

Blue Ridge Paper Response

The April 27, 2006 BART Exemption Modeling Report has been previously submitted to NCDAQ. The October 2006 date used by EPA in the comment above appears to be a typographical error. Additional copies may be provided upon request.

9. EPA Comment

Deciview Thresholds - The document states in several places that "... the change in modeled visibility impact...is less than the 1 deciview threshold of human perception for changes in visibility." This statement implies that the controls are not considered to make enough of an improvement in visibility at the Class I areas identified in the report. We note, however, that there is no bright line for evaluating in the BART determination analysis the degree of visibility improvement that is considered significant enough to warrant BART controls. Rather, a State has flexibility in setting absolute thresholds and determining the weight and significance to be assigned to each BART factor. (See 70 FR 39170, 1st col., July 6, 2005.) Also, this statement does not recognize that a source may be *contributing* to visibility impairment at a Class I area.

Blue Ridge Paper Response

The Regional Haze Rule defines "visibility impairment" as "any humanly perceptible change in visibility from that which would have existed under natural conditions" (see Federal Register Vol. 64, No. 126, page 35764). EPA states numerous times in the preamble and the rule that these thresholds are humanly perceptible thresholds (see Federal Register Vol. 70, No. 128, page 39119, footnote 28 and page 39120, footnote 32). This is the basis for using human perception in the report.

In order to evaluate the various control scenarios as part of the BART evaluation, the change in visibility was determined for the mill as compared to natural conditions as required by the BART rule. Thus, since we are required by the BART rule to evaluate the impact that our emissions would have on natural visibility conditions at each Class I area, it must be assumed that no other sources of air emissions would exist other than those from sources at the mill for the purpose of the analysis. According to 40 CFR Part 51, Appendix Y, an individual BART-eligible source is considered to "contribute" to visibility impairment in a Class I area if the modeled 98th percentile change in dv is equal to or greater than the "contribution threshold." The contribution threshold is 0.5 deciview. Since the modeled change in visibility for each control scenario is less than the 0.5 dv contribution threshold as compared to natural conditions, it is appropriate to state that a control scenario would not result in a humanly perceptible change as compared to natural conditions.

Furthermore, the existing regional haze in the subject Class I areas is on the order of 35 dv. Based on the modeling analyses performed in the BART evaluation, the greatest change in visibility is 0.383 dv. This would be less than a 1% reduction in regional haze as compared to existing regional haze conditions. Based on the magnitude of costs for the control scenarios with minimal improvement in visibility, BART would be no further controls.

Enclosure 3

EPA Comment - Below are clarifications we wish to note on certain statements in the text. (The location of the text in the document is identified in parentheses.)

1. BACT Cost Effectiveness Comparisons (Section 1.2, P.1-1; cover letter, P.I) The document makes the following statement: "As a comparison, costs from \$3,000 to \$5,000 per ton of emissions reduction are generally considered cost prohibitive for BACT evaluations." The Agency has not established cost effectiveness values considered cost prohibitive in regulation or policy. Also, these BACT cost effectiveness numbers may not be directly applicable for use in the BART cost analysis as BACT costs can apply to a new source adding on controls, whereas BART costs for retrofit technology may need to be weighed differently. The State will identify what costs are reasonable or not. Where data are available, we recommend use of a comparative approach for costs, I.e., compare cost effectiveness numbers to a similar facility which operates with controls under similar conditions. Another way of stating this is as follows.

If comparable emissions units are operating with controls, the owner of the BART-affected unit should show why control costs are prohibitive for the BART-affected unit, even though they are acceptable for similar controlled units in operation.

Blue Ridge Paper Response

The BACT costs per ton of emissions was provided to help provide a benchmark for comparing cost estimates developed for the BART analysis. The report does not state that the same costs should be applied to the BART evaluation.

2. BART-Eligibility Descriptions (Section 2.2, P.2-2; Section 3.1, P. 3.1) *Potential to Emit (PTE) Thresholds:* The PTE threshold provided for BART-eligible sources should be corrected to read, "... the potential to emit ~~more than~~ 250 tons per year ~~or more~~ ..." (See 40 CFR 51.301, "Definitions," *Existing stationary facility.*)

Blue Ridge Paper Response

Blue Ridge acknowledges the requested change. If the North Carolina Division of Air Quality requests a complete amended document then the change will be incorporated into the text.

3. Due date for Regional Haze SIPs (Section 2.2, P. 2-3)
The document identifies a due date for Regional Haze SIPs of January 2008. To clarify, the due date for Regional Haze SIPs specified in the

Regional Haze regulations at 40 CFR 51.308 (b) is: “ ... no later than December 17,2007.”

Blue Ridge Paper Response

Blue Ridge acknowledges the requested change. If the North Carolina Division of Air Quality requests a complete amended document then the change will be incorporated into the text. We would note that this is only an editorial change, both statements are correct as written.

4. Line-of-Sight (LOS)

(a) The document refers to a proposed LOS approach in several places and presents data for comparison on page 2-5. We recommend excluding LOS documentation since, as the report indicates, this specific approach is not appropriate for BART modeling purposes.

(b) The document provides selected definitions from 40 CFR 51. We wish to clarify that the definitions provided in Section 2.1 for *Line-of-Sight (LOS)* and *Just Noticeable Change* are not from the Definitions section of the Regional Haze regulations (40 CFR 51.301, “Definitions”).

Blue Ridge Paper Response

Blue Ridge continues to maintain that the line-of-sight approach is the technically appropriate refined method for evaluating visibility impacts for BART exemption modeling when comparing a single source to the humanly perceptible change value of 1 deciview. Furthermore, this is consistent with the definition and scientific basis of a deciview. An approximate one (1.0) deciview change was defined by Pitchford and Malm (1992) as a “just noticeable change” to a human when the background visual range equals the line-of-sight (LOS) of the observer. According to L. Willard Richards in “Use of the Deciview Haze Index as an Indicator for Regional Haze,” if a shorter LOS distance than the background visual range (natural conditions) is used in performing the calculations then a higher extinction value, or deciview, is needed to cause a “just noticeable change.” In other words, when the LOS is less than the background visual range, then it would require a higher deciview value in order to be a “just noticeable change.” Thus, in order to more accurately compare the impact of a single source on a Class I area for comparison to the deciview thresholds, the deciview change would need to be calculated along the human line-of-sight that is equal to the background visual range as opposed to a single receptor point in the Class I area. The modeling we included in the BART evaluation calculates the change over a shorter distance than the background visual range and thus overestimates the impact that the BART eligible units have on each Class I area.

5. Permit Changes (Section 4.2, PA-4)

The document asserts that the electrostatic precipitators (ESPs) on each RF exceed the Maximum Achievable Control Technology (MACT) standard for particulate matter (PM), and that this level of control is already required in the facility's Title V operating permit. The BART Guidelines say if the most stringent control available is adopted, it must be made federally enforceable for purposes of BART. Thus, the SIP and potentially the facility's permit must be modified to include a statement that these controls and operating conditions on the two recovery furnaces also serve to satisfy BART for PM.

Blue Ridge Paper Response - The submitted document included a request to incorporate "no further controls" as BART into the Title V operating permit for Blue Ridge.

6. References (Tables 4-2, 4-4, 4-6)

The EPA Cost Manual references for Tables 4-2, 4-4, and 4-6 are confusing as written, which made it difficult to find the appropriate citations. Chapter 1, December 1995, is cited in the EPA Cost Manual in these cost references. Since there are presently nine chapters labeled "Chapter 1" in the Cost Manual dated January 2002, we suggest that these references be clarified to include the relevant section and chapter title. This will enable reviewers to find the referenced portions of the document. In this case, the relevant items we suggest to include in these Cost Manual references are italicized as follows: "*EPA Air Pollution Control Cost Control Manual, sixth edition (January 2002), EPA 452-02-001, Section 5.2, Chapter 1, "Wet Scrubbers for Acid Gas," December 1995.*" (The current EPA Cost Manual is available at: <http://www.epa.gov/Itncatc1/products.htm/#cccinfo>.)

Blue Ridge Paper Response - The cost estimate for the installation of a scrubber on the recovery furnaces has been revised and is included in Attachment 1 to this correspondence.

7. Table 4-1 – "Summary of RBLC Database for SO₂ Control Technologies"

It appears that the following four "RACT/BACT/LAER (RBLC)" Clearinghouse entries of facilities with SO₂ controls on their RFs were either inadvertently omitted from Table 4-1 or slightly different search criteria may have been used. We used the following search criteria: default time span of 10 years back, Process Type: 30.211 "Kraft Recovery Furnaces/Boilers," Pollutant: "SO_x". For completeness, we suggest including these entries if they were omitted in error. The following control descriptions are included here for your convenience:

- LA-0201, Weyerhaeuser Company, Red River Mill facility (Proper Boiler Design and Operation);
- LA-0207, International Paper Co, Mansfield Mill (Proper Design, Good, Combustion Practices, Firing Low Sulfur Fuel, and a 10% Annual Capacity Factor for Fossil Fuels);
- MS-0078, Georgia Pacific Corporation, Monticello Mill (Combustion Control and Furnace Design); and
- NC-0108, International Paper, Roanoke Rapids Mill (Furnace Design and Combustion optimization).

Based on the RBLC search we performed, it also appears that certain RBLC entries with a “No Controls Feasible” label are not included in Table 4-1. We are unclear as to the reason for this. For completeness, we suggest that the table could either include all or exclude all facilities with a “No Controls Feasible” label.

Blue Ridge Paper Response - Please refer to the sixth entry in Table 4-1. Summary of RBLC Database for SO₂ Control Technologies Installed on Recovery Furnaces, this line contains the NC-0108 entry that is referenced above as a missing entry. Entries LA-0201 and LA-0207 are shown in the RBLC database as a draft determination, therefore, these entries were not included. Entry MS-0078 did not appear in our original search of the database. But as described above, the control method is proper combustion and design of the furnace. This entry does not change the conclusions drawn in the report.

8. Visibility Impact Thresholds (Section 4.1.5, P. 4-3)

Section 4.1.5 provides a summary of Step 5 of the BART Guidelines. The second paragraph of this section states: “If the net visibility improvement is less than the humanly perceptible change, then there is no need for the facility to implement the control technologies because the resulting visibility impacts would be negligible.” The BART Guidelines do not make such an assertion. Rather, the Guidelines provide flexibility to the States with setting thresholds and weighing each of the BART factors. (See 70 FR 39170, 1st col., July 6, 2005.) All of the statutory factors should be used in the determination of whether or not BART controls are needed. Visibility improvement based on modeling results is only one of the factors that should be assessed in this decision.

Blue Ridge Paper Response - Blue Ridge acknowledges the comment but does not feel a modification to the report text is warranted.

9. 22nd highest values for the two worst-case years (Section 5.8. P. 5-7)
Page 5-7 of the document states that a spreadsheet was used to determine the 22nd highest values for the two worst-case years. The 98th percentile value for an individual year is the 8th highest value, so it is unclear why the report references the 22nd highest value. This appears to be a typographical error.

Blue Ridge Paper Response - This is a typographical error in the report; the 8th highest value was the reported modeling result.

National Park Service Comments

NPS General Comments

On the last page of the Introduction, BRP states: "...the change in modeled visibility impact...is less than the 1 deciview threshold of human perception for changes in visibility...Therefore, BART is no further controls." Further, page 4-3 states, "If the net visibility improvement is less than the humanly perceptible change, then there is no need for the facility to implement the control technologies because the resulting visibility impacts would be negligible." We acknowledge that "visibility improvement that would result from controlling the emissions" is one of the factors in a BART analysis. However, the BART decision should not be based on perceptibility. Because BRP's position is contrary to EPA Guidance, we ask that BRP show us the basis for this assertion.

Blue Ridge Paper Response

The BART evaluation was performed as described in Appendix Y to 40 CFR 51. The following 5-step process was utilized to conduct the case-by-case BART analysis. The five steps are:

- *Step 1—Identify All Available Retrofit Control Technologies,*
- *Step 2— Eliminate Technically Infeasible Options,*
- *Step 3— Evaluate Control Effectiveness of Remaining Control Technologies,*
- *Step 4— Evaluate Impacts and Document the Results, and*
- *Step 5—Evaluate Visibility Impacts.*

NPS Comment - We have the following comments regarding Table 4-2 which presents a cost/benefit analysis for controlling SO₂ from the recovery furnaces:

- BRP refers to a vendor quote for the scrubber installation – that should be provided.
- While we believe it is legitimate to account for the costs of lost production and make-up, we would like to see the actual calculations to support these very large numbers.
- BRP refers to a 7/19/06 vendor e-mail for the installation of a new fan and ductwork – that should be provided.
- The reference for the cost of new switch gear installation is missing and should be provided.
- If waste caustic is available from the bleach plant – if there is one – it could be used as the scrubbing reagent, thus reducing reagent and disposal costs – this should be investigated.
- The Capital Recovery Factor is inflated. The OAQPS Control Cost

Manual recommends 7% interest over a 15-year life, not the 15% over ten years used by BRP.

- BRP should document the 90% scrubber efficiency assumption – it seems low.

Blue Ridge Paper Response - Attachment 1 to this correspondence includes a copy of the quote received from MECS (formerly Monsanto Enviro-Chem). Also include in this Attachment is a revised Table 4-2. This table clearly delineates all of the inputs for determining lost production. All of the costs for new fan and ductwork are also clearly defined in the revised table.

Blue Ridge is currently limited by the amount of caustic available for the mill. Material must be purchased and brought on site for make-up. However, in order to present a conservative estimate of costs, the revised scrubber calculations have assumed a caustic scrubbing medium in lieu of limestone.

Please refer to the detailed response to Comment No. 9 from Enclosure No. 1. This comment outlines the appropriateness of using a 15% interest rate and a 10-year life.

Sulfur dioxide emissions from a recovery boiler are not consistent, emission levels tend to run in “spikes.” Since there is not a steady loading of sulfur dioxide to the scrubber, the efficiency of the unit will not be maximized. Therefore, Blue Ridge feels that the use of 90% control is appropriate.

NPS Comment - We have the following comments regarding Table 4-4 which presents a cost/benefit analysis for controlling NOx from the recovery furnaces:

- BRP should provide documentation to support its cost estimates.
- While we believe it is legitimate to account for the costs of lost production and make up, those costs should not be included in the base for estimating Indirect Annual Costs.
- The Capital Recovery Factor is inflated. The OAQPS Control Cost Manual recommends 7% interest over a 15-year life, not the 15% over ten years used by BRP.
- BRP should document the 40% control efficiency assumption.

The costs associated with lost production are accounted in the Indirect Installation Cost. The Indirect Installation Cost in turn is a component of the Total Capital Investment; therefore these costs are incorporated into the capital recovery factor.

Please refer to the detailed response to Comment No. 9 from Enclosure No. 1. This comment clearly outlines the appropriateness of using a 15% interest rate and a 10-year life.

The 40% control efficiency has been documented in the submittal based on

information provided by the National Council for Air and Stream Improvement. Please refer to Corporate Correspondents Memorandum CC 06-014 entitled “Retrofit Control Technology Assessment for NO_x, SO₂, and PM Emissions from Kraft Pulp and Paper Mill Unit Operations.” In fact, the memorandum indicates that the installation of quaternary air reduces NO_x emissions by 20-40%. Therefore, we have been conservative in our inclusion of 40%.

Attachment 1
Revised Cost Estimate

Blue Ridge Paper Products, Inc.

Canton, North Carolina

Table 4-2. Cost Estimate for Installation of a Wet Scrubber on Recovery Furnace No. 10 or 11 - REVISED

Total Capital Investment is the sum of the total direct cost, the total direct installation costs (including retrofit cost considerations) and the indirect installation costs.

Direct Costs (Material and labor involved in actual installation of the facility)

1. Cost of Scrubber (including scrubber, major mechanical components, instrumentation, and structural steel)

\$3,888,000.00 (Please refer to the attached e-mail from Cristina Kulczycki of MECS [formerly Monsanto Enviro-Chem])

As shown in the attached quote, we are conservatively using the low-end of the cost estimate (\$6,000,000-\$14,000,000) to ensure that our numbers are representative of the conditions at Blue Ridge. Based on information provided by the vendor, we have then multiplied this value by 60% to obtain capital investment of the identified components. Freight is estimated at 5%, Taxes at 3%.

2. Modifications to Existing Ductwork and New Stack

<i>Alloy Fabricated Materials - Ductwork</i>	Given Information	Material (\$/given)	Cost ⁴ (\$)	Delivered Cost (\$)
Inlet ductwork to scrubber , 13'x13' x 300' long, 2205 SS ¹	300 ft	\$11,011.00	\$3,303,300.00	\$3,567,564
Outlet ductwork to scrubber , 13'x13' x 50' long, 2205 SS ¹	50 ft	\$11,011.00	\$550,550.00	\$594,594
External stiffeners for inlet ductwork, 30lb/ft shapes ²	6,240 ft	\$59.40	\$370,656.00	\$400,308
External stiffeners for outlet ductwork, 30lb/ft shapes ²	1,040 ft	\$59.40	\$61,776.00	\$66,718
Structural framing for inlet ductwork support, 50' high	75 tons	\$3,960.00	\$297,000.00	\$320,760
Structural framing for ductwork support, 50' high	13 tons	\$3,960.00	\$49,500.00	\$53,460
Stack, 100 ft tall, 12' dia. (erected price, including foundations)				\$8,147,189
Total Cost for Modifications to Existing Ductwork and New Stack				\$13,150,594

1 - Recent unit pricing from first quarter 2006 for materials for 2205 SS material is \$6.05/lb with a plate density of 35lb/ft2

2 - Recent unit pricing from first quarter 2006 for materials, unit price of \$1.98/lb for CS

3 - Typical ductwork is supported on framing that is about 2 - 3 tons of material total at each support location, with the supports spaced 10 to 15' apart.

4 - Cost is FOB Indiana, Freight is assumed 5%, Taxes 3%

3. New ID Fan

\$772,200.00 ID Fan (approximately 1000 HP, with 4160 motor)

Cost of fan is \$715,000 FOB in Indiana, Freight is estimated at 5%, Taxes at 3%.

4. New Switch Gear

\$500,000.00 The current power distribution system is operating at maximum capacity and a new switch gear would be required to operate a new fan. Cost was provided by Mill personnel.

Direct Installation Costs (Expenses not directly involved with material and labor of actual installation)

1. Retrofit Cost Considerations

0.15 Retrofit Factor

Factor is applied to the ductwork costs shown in Item No. 2 above.

\$750,510.68 Retrofit Cost Consideration

Blue Ridge Paper Products, Inc.

Canton, North Carolina

Table 4-2. Cost Estimate for Installation of a Wet Scrubber on Recovery Furnace No. 10 or 11 - REVISED

Indirect Installation Costs

1. Lost Pulp Production

\$550.00 \$/ton, Cost to Purchase Dry Pulp
700 ton/day/furnace, Production Capacity
14 days, Total Recovery Furnace Outage Time to Install Scrubber

\$5,390,000.00 Total Lost Production Costs

2. Lost Power Production

786.5 MMBtu/hr, Heat Input Rating of Recovery Furnace
0.293 Watts/Btu/hr, Conversion Factor
230.5 Mw, Capacity of Single Recovery Furnace
30% Conversion from Mw to Mwe (heat energy to electric energy)

69.15 Mwe, Electric Energy Provided by Recovery Boiler

\$0.067 \$/Kw-hr, Cost to Purchase Electricity from the Grid
\$0.025 \$/Kw-hr, Cost to Manufacture Electricity
\$0.042 \$/Kw-hr, Incremental Cost of Purchased Power

\$975,842.92 Total Cost Associated with Lost Power Production

Total Capital Investment

\$3,888,000.00 Cost of Scrubber
\$13,150,594 Total Cost for Modifications to Existing Ductwork and New Stack
\$772,200.00 New ID Fan
\$500,000.00 New Switch Gear
\$750,510.68 Retrofit Cost Considerations
\$5,390,000.00 Total Lost Production Costs
\$975,842.92 Total Cost Associated with Lost Power Production

\$25,427,147.42 Total Capital Investment

Annual Operating Costs

Direct Annual Costs, DC, Operating

\$28.00 \$/hr, Operator Labor Rate
1 hr/Shift, Operator Labor Dedicated to Operating Scrubber

\$35.00 \$/hr, Supervisor Labor Rate
0.15 hr/Shift, Supervisor Labor Dedicated to Operating Scrubber

1,095 Shifts/yr, Assumes 3 shifts per day, 365 days per year

\$30,660.00 \$/yr, Operator Labor
\$5,748.75 \$/yr, Supervisor Labor

Blue Ridge Paper Products, Inc.

Canton, North Carolina

Table 4-2. Cost Estimate for Installation of a Wet Scrubber on Recovery Furnace No. 10 or 11 - REVISED

Direct Annual Costs, DC, Maintenance

\$28.00 \$/hr, Maintenance Labor Rate
1 hr/Shift, Maintenance Labor

1,095 Shifts/yr, Assumes 3 shifts per day, 365 days per year

\$30,660.00 \$/yr, Maintenance Labor
\$30,660.00 Maintenance Materials

Direct Annual Costs, DC, Utilities

\$319.00 \$/hp-yr, Mill Specific Electricity Cost
1,000 hp, Approximate Size of New Fan
\$319,000.00 \$/yr, Annual Energy Cost

10 gal/min, Minimum Flow Rate through Scrubber
\$0.09 \$/1000 gal, Cost of Mill Water
\$473.04 \$/yr, Water Cost

\$280,000.00 \$/yr, Caustic Cost Provided via MECS in 2/14/07 Phonecon

\$697,201.79 Total Direct Annual Operating Costs

Indirect Annual Costs, Overhead

60% Percent of Annual Direct Costs (Excluding Utilities)
\$58,637.25 \$/yr, Overhead Costs

Indirect Annual Costs, Administration, Property, and Insurance

2% Administration Costs, Percent of Total Capital Investment
1% Property Costs, Percent of Total Capital Investment
1% Insurance Costs, Percent of Total Capital Investment
\$1,017,085.90 \$/yr, Administrative, Property, and Insurance Costs

Indirect Annual Costs, Capital Recovery Factor

15% Interest Rate
10 yrs, Payback Period

Capital Recovery Factor = $i (1 + i) ^ n / ((1+i)^n - 1)$; i= interest rate , n= years

0.1725 Capital Recovery Factor

\$4,386,182.93 \$/yr, Capital Recovery

\$5,461,906.08 Total Indirect Annual Operating Costs

\$6,159,107.87 Total Annual Operating Costs

Blue Ridge Paper Products, Inc.

Canton, North Carolina

Table 4-2. Cost Estimate for Installation of a Wet Scrubber on Recovery Furnace No. 10 or 11 - REVISED

Cost Effectiveness

128.3 lb/hr, SO2 Emission Rate from Each Scrubber
8760 hr/yr, Annual Operating Hours
561.954 ton/yr, Annual Potential SO2 Emissions

90% Reduction by Scrubber

505.76 ton/yr, SO2 Reductions from Scrubber

\$12,177.96 \$/ton, Cost Effectiveness of Scrubber Installation



"KULCZYCKI, CRISTINA R
[STL]"
<CRISTINA.R.KULCZYCKI@
MECSGLOBAL.COM>

02/19/2007 02:48 PM

To <Cynthia_Winston@URSCorp.com>

cc

bcc

Subject RE: Quote for Recovery Boiler SO2 Control System

History:

✉ This message has been replied to.

Hi Cynthia,

Enclosed is some preliminary vessel sizing and utility information for the scrubber that we discussed last week.

Is there anything else that you need from me at this point?

Thanks,

Cristina

-----Original Message-----

From: KULCZYCKI, CRISTINA R [STL]
Sent: Thursday, February 15, 2007 2:11 PM
To: 'Cynthia_Winston@URSCorp.com'
Subject: RE: Quote for Recovery Boiler SO2 Control System

Cynthia,

There is no money for ductwork in the estimate.

Are you asking what the split is on equipment versus installation? If so, it depends on which items you put in installation and which items you put in equipment. We generally say that equipment is about 60% of the total installed cost.

Thanks,

Cristina

-----Original Message-----

From: Cynthia_Winston@URSCorp.com [mailto:Cynthia_Winston@URSCorp.com]
Sent: Thursday, February 15, 2007 1:59 PM
To: KULCZYCKI, CRISTINA R [STL]
Subject: RE: Quote for Recovery Boiler SO2 Control System

Cristina - Thank you for the prompt response!!

Could you please clarify the portion of the cost associated only with the scrubber, instruments, piping (not to include ductwork routing the gas to the scrubber), and structural steel.

Again thank you for your assistance!!

Cyndi

Cynthia Winston, P.E.
URS Corporation

1600 Perimeter Park Drive, Suite 100
Morrisville, North Carolina 27560
(919) 461-1230 - Phone
(919) 461-1415 - Fax

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"KULCZYCKI,
CRISTINA R [STL]"
<CRISTINA.R.KULCZ
To YCKI@MECSGLOBAL.C <Cynthia_Winston@URSCorp.com>
OM>
cc <Randall_Taylor@URSCorp.com>,
02/15/2007 11:22 <Amy_Marshall@URSCorp.com>,
AM "PURICELLI, STEVEN M [STL]"
<STEVEN.M.PURICELLI@MECSGLOBAL.COM>
Subject RE: Quote for Recovery Boiler SO2
Control System

Cynthia,

If I am doing the math correctly, the inlet flowrate is 365,562 acfm. That is quite a large flowrate.

Without a detailed gas composition I can't calculate the quenched gas flowrate (which is the flowrate used to design the scrubber); however, I think you are in the 10 million dollar price range +/- 40% (i.e. 6 to 14 million). This number includes installation of the scrubber and stack (assuming a reasonable height), major mechanical equipment, instruments, piping, and structural steel.

We have been doing a lot of refinery work where 316 S/S is the predominant material used (for the vessel and piping). If we could use FRP we might be towards the lower end of the above price range. In addition, we would need to know if the liquid effluent needs to be oxidized and filtered for solids. If it isn't oxidized, the effluent will contain a 10% solution of sodium sulfite and sodium bisulfite. If you do oxidize, the effluent will contain 10% sodium sulfate. Anyway, oxidation and filtration adds to the cost of the system. If you don't oxidize or filter the effluent you may be towards the middle to lower end of the above range.

Finally, if a system fan is required you will be on the higher end of the above price range.

We can spend a bit more time and work up an actual budget estimate; however, you need to allow at least two to four weeks for that process. Also, if you do want us to do that we will need a complete gas composition (i.e. % N2, % O2, etc., etc.) as well as the inlet pressure to the Dynawave. In addition, we would need to know how you want the effluent handled.

Hope this helps. If you have any other questions please give me a call at 314-275-5787.

Cristina Kulczycki

-----Original Message-----

From: Cynthia_Winston@URSCorp.com [mailto:Cynthia_Winston@URSCorp.com]
Sent: Wednesday, February 14, 2007 1:08 PM
To: KULCZYCKI, CRISTINA R [STL]
Cc: Randall_Taylor@URSCorp.com; Amy_Marshall@URSCorp.com
Subject: Quote for Recovery Boiler SO2 Control System

Cristina -

Thank you for taking time to discuss the MECS SO2 control system with me today. We are looking for a budgetary estimate for the installation of an SO2 reduction device to be installed on a recovery boiler at a pulp and paper mill in North Carolina. The device should be able to control SO2 emissions by 90%. The SO2 loading to the device is 128.3 pounds per

hour. H2SO4 emissions from the unit are 0.18 pounds per hour. Please cost the system using caustic. At the current time the mill is black liquor solids limited and therefore, BL scrubbing is not an option. The exhaust stream is approximately 400 degrees Kelvin with 172.5 cubic meters per second of air flow.

Thank you again for your assistance! We are on a tight schedule so any information you can provide is helpful.

Please do not hesitate to contact me for further clarification!! Cyndi

Cynthia Winston, P.E.
URS Corporation
1600 Perimeter Park Drive, Suite 100
Morrisville, North Carolina 27560
(919) 461-1230 - Phone
(919) 461-1415 - Fax

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MessageLabs. URS 2007 Operating Summary Tables Internal.doc

URS Corporation

DynaWave Tailgas Scrubber Design Conditions

Inlet Conditions	
Scrubber Inlet Flow Rate, acfm	365,500
SO ₂ , lb/hr	128
Temperature, °F	260

Scrubber Operations Summary	
SO ₂ Removal Efficiency*	90
SO ₂ Outlet, lb/hr (ppmvd)	12 (5)
System Gas DP, inches wc	12
Scrubber Exit Flow Rate, acfm	314,500
Liquid Circulation Rate to Each Reverse Jet, gpm	12,500
Exit Temperature, °F	114
Caustic Reagent Usage, lb/h	145 (100% NaOH)
Liquid Effluent Flow Rate, gpm	5 (10% Na ₂ SO ₃)
Reverse Jet Pump, HP	400

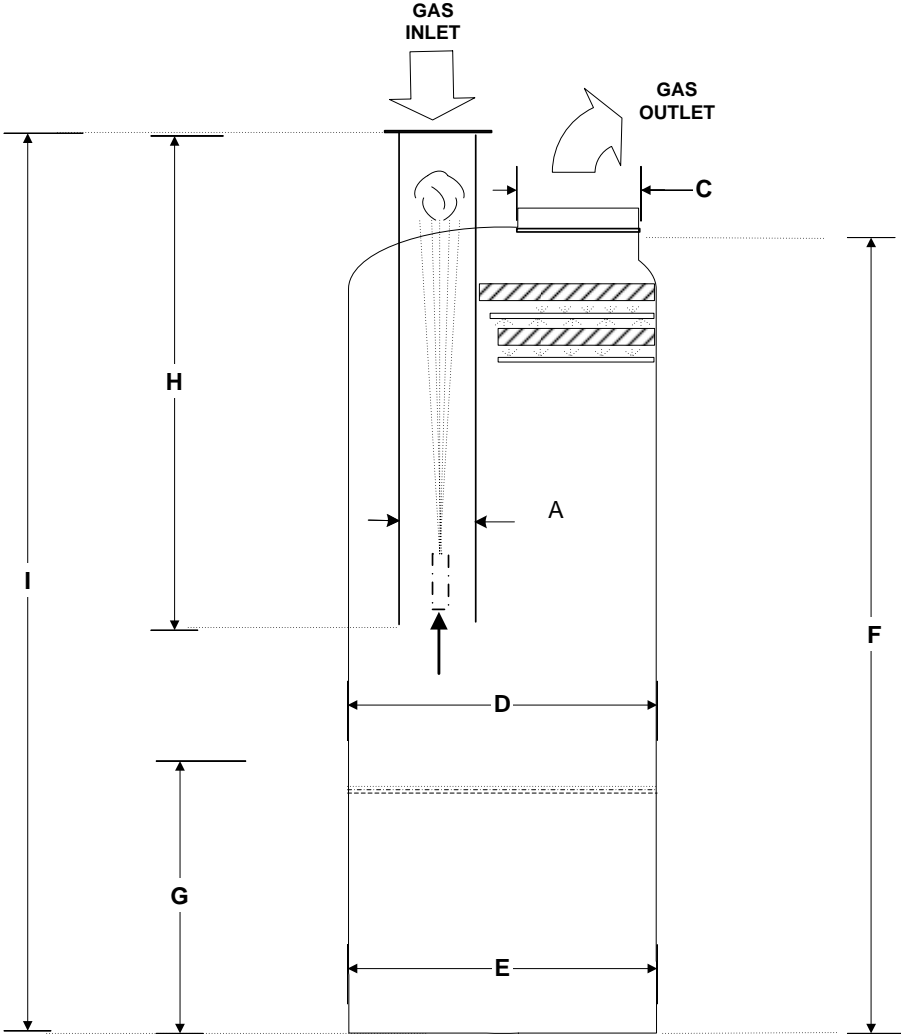
* To a lower limit of 12 ppmv

Scrubber Dimensions	
Nozzle Size, inches**	16 @ 10 psi
Inlet Diameter (A), inches	106
Outlet Diameter (C), ft	5
Vessel Diameter (D), ft	24
Sump Diameter (E), ft	24
Vessel Height (F), ft	55
Sump Height (G), ft	13
Height of Inlet Barrel (H) ft	22
Overall Height (I), ft	56

** This is a three nozzle arrangement.

NOTE: These are preliminary designs. Firm designs may vary based upon final specifications and requirements.

All Dimensions are approximate and subject to change after detailed design. Drawing not to scale.



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DynaWave
Engineered Scrubbing Systems

URS Corporation

RFK
February 19, 2007

Thomas Bell/Austin/URSCorp

07/19/2006 04:16 PM

To Cynthia Winston/Morrisville/URSCorp@URSCorp

cc Trey Pavy/Austin/URSCorp@URSCorp, Blake
Stapper/Austin/URSCorp@URSCorp

bcc

Subject Scrubber support equipment costs

Cyndy,

Attached is a spreadsheet containing rough costs for the equipment about which we spoke over the phone. These numbers are based on actual purchased equipment and/or budget estimates that were obtained for similar sized components for some of the AdvaTech projects from first quarter 2006. The stack price is a lump sum number including construction since that is typically how that item is furnished. The balance of the numbers are equipment only with no contingency added. I tried to include some comments in the cells to explain the basis of the numbers in case you needed it.

I hope this helps.



Scrubber auxilliary costs 7.19.06.xls

Thanks.

Thomas Bell, P.E.
URS Corporation

512-419-5005 (ph)
512-454-8807 (fax)

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**North Carolina Papermill
Scrubber Auxilliary equipment costs**

Summary		QTY	Unit	Cost (\$)			
5							
6	Major Capital Equipment						\$21,097,782
7	Freight	3.0%					\$632,933
8	Warranty	5.0%					\$1,054,889
12							
13	FGD Upgrades Material Total						\$22,785,605
14							
15	Process Studies and Modeling						
16	Engineering						
17	Construction Assistance, Startup and Training						
18							
19	Engineering Services Costs						\$0
20							
	Project Contingency						
23	Total Project Cost incl. Fee and Contingency (URS Scope)						\$22,785,605
24							
25	Detail						
26	Scrubber Auxilliary Equipment						
27	Major Capital Equipment						
28	ID Fan (approximately 1000 HP, with 4160 motor)	1 ea		715,000	\$715,000	\$28.16	\$715,000
29	Alloy Fabricated Materials - Ductwork						
30	Inlet ductwork to scrubber , 13'x13' x 300' long, 2205 SS	300 ft		11,011	\$3,303,300	0 \$28.16	\$0 \$3,303,300
31	Outlet ductwork to scrubber , 13'x13' x 50' long, 2205 SS	50 ft		11,011	\$550,550	0 \$28.16	\$0 \$550,550
32	External stiffeners for inlet ductwork, 30lb/ft shapes	6,240 ft		59	\$370,656	0 \$28.16	\$0 \$370,656
33	External stiffeners for outlet ductwork, 30lb/ft shapes	1,040 ft		59	\$61,776	0 \$28.16	\$0 \$61,776
34	Structural framing for inlet ductwork support, 50' high	75 tons		3,960	\$297,000	0 \$28.16	\$0 \$297,000
35	Structural framing for ductwork support, 50' high	13 tons		3,960	\$49,500	0 \$28.16	\$0 \$49,500
36	Stack, 300 ft tall, 12' dia. (erected price, including foundations)					\$15,750,000	\$15,750,000
37	Total major capital equipment				\$5,347,782	\$15,750,000	\$21,097,782

APPENDIX B

NCASI Corporate Correspondents Memorandum on Retrofit Controls




NATIONAL COUNCIL FOR AIR AND STREAM IMPROVEMENT, INC.
P.O. Box 13318, Research Triangle Park, NC 27709-3318
Phone (919) 941-6400 Fax (919) 941-6401

Ronald A. Yeske, Ph.D.
President
(919) 941-6404

June 9, 2006

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

FROM: Ronald A. Yeske 

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 retrofitted 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 µm.

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

Public Notice for BART Title V Air Permit Modification

NORTH CAROLINA DEPARTMENT OF ENVIRONMENT & NATURAL RESOURCES
PUBLIC NOTICE AND NOTICE OF INTENT TO ISSUE AIR QUALITY PERMITS

Notice is hereby given for a public hearing to be heard by the North Carolina Department of Environment and Natural Resources (DENR), Division of Air Quality (DAQ), concerning the proposed Regional Haze state implementation plan (SIP) and preliminary best available retrofit technology (BART) determinations. DAQ also hereby gives notice of intent to issue an Air Quality Permit to each of the facilities noted in the information section below.

PURPOSE: The hearing is intended to inform interested parties on the Regional Haze SIP including BART determinations and intent to issue related Air Quality Permits.

DATES AND LOCATIONS: November 13, 2007, 6:30 p.m., Asheville-Buncombe Technical Community College Main Campus, 1st Floor Lecture Room, Simpson Administrative Building, 340 Victoria Road, Asheville, NC 28801.

November 15, 2007, 6:30 p.m., at the DENR Washington Regional Office, 943 Washington Square Mall, DENR Hearing Room, Washington, NC, 27889.

COMMENT PROCEDURES: All persons interested in these matters are invited to attend the public hearing. Any person desiring to comment is requested to submit a written statement for inclusion in the record of proceedings at the public hearing. The hearing officer may limit oral presentation lengths if many people want to speak. The hearing record will remain open until November 26, 2007, to receive additional written statements.

INFORMATION: Copies of the proposed Regional Haze SIP, the BART determinations, related permit reviews and draft permits, and a summary of initial Federal Land Managers comments on the Regional Haze SIP may be downloaded at <http://daq.state.nc.us/planning/nc.sip.shtml>. The documents may also be reviewed at the offices of the North Carolina Department of Environment and Natural Resources, Division of Air Quality, located in:

Raleigh, Planning Section	(919) 715-7670
Raleigh, Permits Section	(919) 715-6237
Asheville Regional Office	(828) 296-4500
Washington Regional Office	(252) 946-6481

Comments should be sent to and additional information concerning the hearings or the proposals may be obtained by contacting:

Ms. Laura Boothe
Acting Chief, Planning Section
Division of Air Quality
1641 Mail Service Center
Raleigh, NC 27699-1641
Phone: (919) 733-1488
Fax: (919) 715-7476

daq.publiccomments@ncmail.net (Note: In the subject line type Regional Haze SIP)

The following two facilities have submitted BART determinations under 15A NCAC 02D .0543 Best Available Retrofit Technology for DAQ to review and have applied for an Air Quality Permit which meets the requirements specified in 15A North Carolina Administrative Code 02Q .0300:

PCS Phosphate Company
1530 NC 306 South
Aurora, NC 27806
Beaufort County
Permit # 04176 T34 App# 0700071.06D

Blue Ridge Paper Company
175 Main Street
Canton, NC 28716
Haywood County
Permit # 08961 – T09 App# 440159.06E

Comments should be sent to and additional information regarding the Air Quality Permits may be obtained by contacting:

Mr. Donald van der Vaart, Ph. D., P.E.
Chief, Air Permits Section
Division of Air Quality
1641 Mail Service Center
Raleigh, NC 27699-1641
Attn: Permits Section
Phone: (919) 715-6253
Fax: (919) 733-5317

All comments received by November 26, 2007 will be considered in the final determinations regarding these Air Quality Permits.

Date: _____

B. Keith Overcash, P.E., Director