Appendix 9J

Emission Limits – Excerpts from ROP for Tilden Mining Company

EU-KILN1
EMISSION UNIT CONDITIONS

PROCESS AND CONTROL EQUIPMENT

EU-KILN1 Unit 1 Grate Kiln Indurating Furnace receives pellets from the balling section, dries and preheats them on a traveling grate which discharges them into a rotary kiln for final induration. Unit 1 main burners are rated at 590 million BTU per hour heat input. The Tilden facility produces hematite pellets and magnetite pellets. Unit 1 is fired with coal, coal/petroleum coke blend, natural gas, or used oil supplied from the 1.5 million gallon storage tank.
Also, blending coke breeze into the green pellets to provide additional heat input for the induration process was authorized in 2002 under Permit to Install #70-02. The unit is controlled with electrostatic precipitators.
{Permits to Install #511-87C, #70-02}

I. EMISSION LIMITS

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. **Arsenic**	1. Arsenic emissions, from firing used oil, shall not exceed 0.0058 tons per rolling 12-calendar month period.[1]	Rolling 12-calendar month period	**Unit 1 Indurating Furnace**	Appendix 7	R336.1224
2. **Cadmium**	2. Cadmium emissions, from firing used oil, shall not exceed 0.0058 tons per rolling 12-calendar month period.[1]	Rolling 12-calendar month period	**Unit 1 Indurating Furnace**	Appendix 7	R336.1224
3. **Chromium (total)**	3. Chromium (total) emissions, from firing used oil, shall not exceed 0.0058 tons per rolling 12-calendar month period.[1]	Rolling 12-calendar month period	**Unit 1 Indurating Furnace**	Appendix 7	R336.1224
4. **Particulate**	4. Particulate a. Particulate emissions shall not exceed 0.01 grains per dry standard cubic foot (gr/dscf) for existing grate kiln indurating furnaces processing *magnetite*. b. Particulate emissions shall not exceed 0.03 grains per dry standard cubic foot (gr/dscf) for existing grate kiln indurating furnaces processing *hematite*.	Test Protocol	**Unit 1 Indurating Furnace**	40 CFR 63 Subparts RRRRR and A	40 CFR Part 63 Subparts RRRRR and A (see TACONITE MACT REQUIREMENTS below)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
5. **Lead**	5. Lead emissions, from firing used oil, shall not exceed 0.017 tons per rolling 12-calendar month period.[1]	Rolling 12-calendar month period	**Unit 1 Indurating Furnace**	Appendix 7	R336.1224
6. **Particulate**	6. Particulate emissions shall not exceed 0.065 pounds per 1000 pounds of exhaust gases, nor 200 pounds per hour.[2]	Test Protocol	**Unit 1 Indurating Furnace**	GC 13, 14, 15	R336.1331
7. **Sulfur Dioxide**	7. Sulfur dioxide emissions shall not exceed 28,800 pounds per calendar day.[2]	Calendar Day	**Unit 1 Indurating Furnace**	VI. 1 VI. 2	R336.1402

II. MATERIAL LIMITS

1. The halogen content of the used oil burned in Unit 1 Indurating Furnace shall not exceed 1000 parts per million, by weight.[1] **[R336.1224]**

2. The maximum feedrate of coke breeze shall not exceed 5 tons per hour.[1] **[R336.1224]**

III. PROCESS OR OPERATIONAL RESTRICTIONS

1. The permittee shall not operate Unit 1 Indurating Furnace unless the electrostatic precipitators are operating properly.[2] **[R336.1910]**

2. The oil burned in Unit 1 Indurating Furnace shall be supplied only from the 1.5 million gallon used oil tank.
[R336.1201(3)]

3. See TACONITE MACT REQUIREMENTS below. **[40 CFR 63 Subparts RRRRR and A]**

IV. DESIGN OR EQUIPMENT PARAMETERS

NA

EU-OREDRYER1
EMISSION UNIT CONDITIONS

PROCESS AND CONTROL EQUIPMENT

EU-OREDRYER1 – Ore Concentrate Dryer #1 is rated at 400 tons per hour throughput and 70 million BTU per hour heat input. The Dryer is fired with natural gas and used oil supplied from the 1.5 million gallon storage tank. Dryer #1 is controlled with a cyclone precleaner and a wet scrubber.
{Permit to Install #511-87C}

I. EMISSION LIMITS

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. **Arsenic**	1. Arsenic emissions, when firing used oil, shall not exceed 0.0009 tons per rolling 12-calendar month period.[1]	Rolling 12-calendar month period	**Ore Dryer #1**	Appendix 7	R336.1224
2. **Cadmium**	2. Cadmium emissions, when firing used oil, shall not exceed 0.0009 tons per rolling 12-calendar month period.[1]	Rolling 12-calendar month period	**Ore Dryer #1**	Appendix 7	R336.1224
3. **Chromium (total)**	3. Chromium (total) emissions, when firing used oil, shall not exceed 0.0009 tons per rolling 12-calendar month period.[1]	Rolling 12-calendar month period	**Ore Dryer #1**	Appendix 7	R336.1224
4. **Particulate**	4. Particulate emissions shall not exceed 0.052 grains per dry standard cubic foot (gr/dscf) for existing Ore Dryers.	Test Protocol	**Ore Dryer #1**	40 CFR 63 Subparts RRRRR and A	40 CFR Part 63 Subparts RRRRR and A (see TACONITE MACT REQUIREMENTS below)
5. **Lead**	5. Lead emissions, when firing used oil, shall not exceed 0.00265 tons per rolling 12-calendar month period.[1]	Rolling 12-calendar month period	**Ore Dryer #1**	Appendix 7	R336.1224
6. **Particulate**	6. Particulate emissions shall not exceed 0.10 pounds per 1000 pounds of exhaust gases, calculated on a dry gas basis.[2]	Test Protocol	**Ore Dryer #1**	GC 13, 14, 15	R336.1331

EU-BOILERS1-2
EMISSION UNIT CONDITIONS

PROCESS AND CONTROL EQUIPMENT

EU-BOILERS1-2 - Boilers #1 and #2 are each rated at 225 million BTU per hour heat input capacity and are fired with natural gas and used oil supplied from the 1.5 million gallon storage tank. Boilers #1 and #2 exhaust from a common stack.
{Permit to Install #511-87C}

I. EMISSION LIMITS

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. **Arsenic**	1. Arsenic emissions, when firing used oil, shall not exceed 0.12 tons per rolling 12-calendar month period.[2]	Rolling 12-calendar month period	**Boilers #1 and #2**	Appendix 7	R336.1224
2. **Cadmium**	2. Cadmium emissions, when firing used oil, shall not exceed 0.12 tons per rolling 12-calendar month period.[2]	Rolling 12-calendar month period	**Boilers #1 and #2**	Appendix 7	R336.1224
3. **Chromium (total)**	3. Chromium (total) emissions, when firing used oil, shall not exceed 0.12 tons per rolling 12-calendar month period.[2]	Rolling 12-calendar month period	**Boilers #1 and #2**	Appendix 7	R336.1224
4. **Lead**	5. Lead emissions, when firing used oil, shall not exceed 0.37 tons per rolling 12-calendar month period.[2]	Rolling 12-calendar month period	**Boilers #1 and #2**	Appendix 7	R336.1224

II. MATERIAL LIMITS

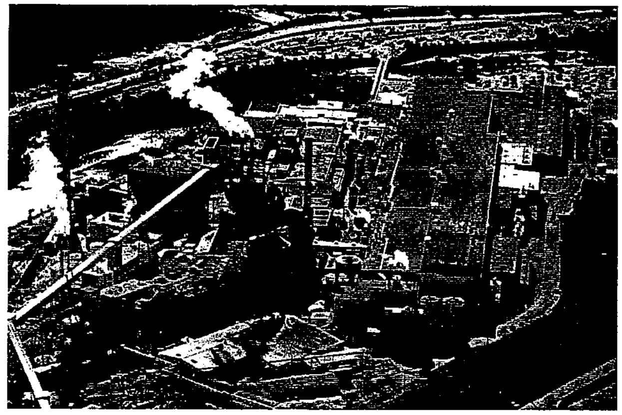
1. The used oil burned in Boilers #1 and #2 shall not exceed a sulfur content of 1.2%, calculated on the basis of 18,000 BTU per pound. **[R336.1401]**

2. The halogen content of the used oil burned in Boilers #1 and #2 shall not exceed 1000 parts per million, by weight.[1] **[R336.1224]**

Appendix 9K

New Page Paper Company BART Technical Analysis

BEST AVAILABLE RETROFIT TECHNOLOGY (BART) ANALYSIS



CASE-BY-CASE BART ANALYSIS
ESCANABA PAPER COMPANY

Prepared in accordance with:
40 CFR Part 51, Subpart P and Appendix Y

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1. BART DETERMINATION ANALYSIS

The following subsections provide an executive summary and background information on the Best Available Retrofit Technology (BART) analysis performed for Escanaba Paper Company's (EPC's) BART eligible sources. An overview of the approach taken to complete the case-by-case BART analysis is provided as well.

1.1 EXECUTIVE SUMMARY

EPC owns and operates a pulp and paper manufacturing mill located in Escanaba, Michigan. EPC is a major source as defined by the federal operating permit program (40 CFR Part 70) and the federal new source review (NSR) program (40 CFR Part 52). In addition, EPC is also subject to the Michigan Title V Renewable Operating Permit (ROP) Regulations listed in Part 2 of the Michigan Air Pollution Control Rules (R336.1210 through R336.1218). Several of the emission units at the facility were originally constructed between 1962 and 1977. As a result of the installation dates as well as the fact that the facility is one of the 26 major source categories listed in the regulation, EPC is also subject to the BART requirements that are part of the Regional Haze Rules specified in 40 CFR Part 51, Subpart P, Protection of Visibility.

Under the Regional Haze rules, an air quality modeling analysis is performed for facilities that have BART eligible sources to determine if the emission units at the facility cause or contribute to visibility impairment at nearby Class I areas. The initial air quality modeling analysis is commonly referred to as a "BART exemption modeling" analysis. EPC performed the exemption modeling analysis and determined that the facility could not be exempted from the BART requirements. As a result, EPC performed a Case-by-Case BART Analysis and a review of the technical feasibility and cost effectiveness of potential air pollution control device alternatives to identify possible control scenarios for emissions of Visibility Impairing Pollutants (VIPs) from the BART eligible sources at the facility.

In accordance with Appendix Y, EPC completed a BART analysis for the BART affected emission units taking into account:

1. Technical feasibility and the cost of compliance;

2. The energy and non-air quality impacts of compliance;
3. Any existing air pollution control technology in use at the source;
4. The remaining useful life of the source (if applicable); and
5. The degree of visibility improvement which may reasonably be anticipated from the use of BART.

The results of this BART analysis indicate that the use of the existing air pollution controls in place at the facility represent BART. This determination was made because any other potential add-on controls would either be technically infeasible, would not be considered cost effective, or would not result in a significant improvement in visibility.

1.2 BACKGROUND

The Regional Haze Rules listed at 40 CFR Part 51.308 (USEPA 2005) include a requirement that certain large stationary sources that were installed between 1962 and 1977 be evaluated for applicability of BART. Specifically, the BART requirements apply to "major stationary sources" that are listed as one of the 26 industrial source categories identified in the Clean Air Act (CAA). Emission units at the major stationary source must have been in existence on August 7, 1977, the date of the 1977 CAA amendments, and had been begun operation after August 7, 1962. If the emission units at a major stationary source collectively have the potential to emit 250 tons per year (tpy) of any single visibility impairing pollutant then the emission units are classified as BART eligible sources. Visibility impairing pollutants (VIP) include sulfur dioxide (SO_2), oxides of nitrogen (NO_X), and particulate matter of 10 microns or less (PM_{10}).

The EPC Mill is a Kraft pulp mill which is one of the 26 industrial source groups listed in the CAA (Kraft pulp mills, NAICS 322121 – North American Industry Classification System). There are several emission units at the Mill that were constructed after 1962 but before 1977. In addition the collective VIP emissions from these sources are greater than 250 tons per year. Consequently, there are five emissions units that are classified as BART eligible. A list of the Mill's BART eligible sources is shown in Table 1-1 along with the VIP emitted by the respective source.

Table 1-1
Escanaba Paper Company BART Eligible Sources

BART Eligible Source	VIP Requiring a Case-by-Case BART analysis
No. 8 Boiler (EU8B13)	SO_2, NO_X, PM_{10}
No. 9 Boiler (EU9B03)	SO_2, NO_X, PM_{10}
No. 10 Recovery Furnace (EURF15)	SO_2, NO_X, PM_{10}
Smelt Dissolving Tank (EUST15)	SO_2, PM_{10}
Lime Kiln (EULK29)	SO_2, NO_X, PM_{10}

Under the Regional Haze rules, an air quality modeling analysis is performed for facilities that have BART eligible sources to determine if the emission units at the facility cause or contribute to visibility impairment at nearby Class I areas. The initial air quality modeling analysis is commonly referred to as a "BART exemption modeling" analysis. If the emissions from the BART eligible sources collectively do not cause or contribute to visibility impairment, then the facility does not need to conduct any further air quality modeling or further analysis of BART controls. However, if it is shown that visibility impairment occurs due to VIP emissions from the BART-eligible sources, then a BART analysis is then required to assess possible retrofit control options for all of the BART eligible sources at the facility.

The United States Environmental Protection Agency (USEPA) provided guidance in the Regional Haze rules for establishing criteria for assessing visibility impairment. The USEPA recommended that an impact on visibility of 1.0 deciviews (dv) be considered to be causing visibility impairment and that an impact on visibility of 0.5 deciviews be considered to be contributing to visibility impairment. The USEPA also recommended that the 98th percentile of modeled 24-hour values be used in the visibility determination. The 98th percentile corresponds to the 8th highest 24-hour modeled value. Facilities whose BART eligible sources cause less than a 0.5 deciview impact can be considered exempt from the BART process.

EPC conducted a BART visibility modeling analysis to determine if the BART eligible sources at the Mill cause or contribute to visibility impairment at the Seney Wilderness area or Isle Royale National Park. Seney Wilderness and Isle Royale National Park are the only Class I areas located within 300 kilometers (km) of the Mill. The visibility modeling indicates that the VIP emissions from the BART eligible sources at the Mill contribute to daily visibility impacts greater than 0.5 deciviews, but less than 1.0 deciview at the Seney Wilderness area. The 98th percentile values were used. No visibility impacts above 0.5 deciviews are predicted for the Isle Royale National Park.

Since the BART eligible emissions units at EPC exceed the BART exemption threshold in the Seney Wilderness, EPC must perform a case-by-case BART analysis (BART analysis) for each of the BART eligible sources at the Mill. The case-by-case BART analysis considered the criteria contained in Section 169A(g) of the CAA and included the following items:

- Technical feasibility and the cost of compliance;
- The energy and non-air quality impacts of compliance;
- Any existing air pollution control technology in use at the source;
- The remaining useful life of the source; and
- The degree of visibility improvement which may reasonably be anticipated from the use of BART.

Sections 2 thru 8 of this document present the technical information and results of the BART analysis.

1.3 CASE-BY-CASE BART ANALYSIS

A BART analysis must be conducted for emissions of each VIP from each BART eligible source. BART determinations are case-by-case analyses that involve an assessment of the availability of applicable technologies capable of sufficiently reducing the emissions of a specific pollutant, as well as an assessment of the economic, energy, and environmental impacts of using each technology. The methodology used in the analysis to determine the appropriate BART level of control follows a process that is similar to the "top-down" best available control technology (top-down BACT) approach that is outlined in Chapter B of the USEPA Draft "New Source Review Workshop Manual" dated October 1990 (USEPA 1990). EPC considered other available guidance documents and resources, including but not limited to: BART determinations for other affected sources; discussions with Michigan Department of Environmental Quality (DEQ) and other state agencies, review of the Regional Haze regulation preamble, and examples presented in Appendix Y to 40 CFR Part 51. Consistent with guidance and Appendix Y to 40 CFR Part 51, this top-down BART analysis includes the following 5 basic steps:

<u>Step 1 – Identify all Available Retrofit Control Technologies.</u>

The first step in the BART control technology analysis is to develop a comprehensive list of potential control technologies and improvements to existing control equipment that could potentially reduce VIP emissions. USEPA data bases including the RACT/BACT/LAER Clearinghouse were consulted. EPC considered controls that were installed pursuant to Prevention of Significant Deterioration (PSD) BACT determinations, New Source Performance Standards (NSPS), and to meet Maximum Achievable Control Technology (MACT) regulations as part of the analysis. For BART eligible units that have post-1990 controls resulting from MACT regulations and, potentially, PSD determinations, USEPA has indicated that it is reasonable to equate the controls as equivalent to BART provided that a discussion *"of whether any new control technologies have subsequently become available"* (USEPA 2005) is made a part of the BART analysis. EPC did not consider a complete redesign of any of the BART eligible emission units as part of the available control alternatives analysis and has not identified control technologies that have not been implemented in the United States.

<u>Step 2 – Eliminate Technically Infeasible Options.</u>

Control technologies are technically infeasible if they have not been installed and operated successfully on a particular type of emission unit or the control technology could not be applied to that type of emission unit. In cases where EPC believes that a certain control technology is not technically feasible, the determination was based on physical, chemical or engineering principles. Similarly, there were other cases where a determination of technical infeasibility was made based on irresolvable logistical or practical problems with the implementation of a control technology such as size of the emission unit, location of the emission unit, site constraints for deploying the control technology, reliability, and adverse impacts on the emission unit operations.

<u>Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies.</u>

EPC determined the expected emissions reductions for each feasible control technology on a consistent, comparable basis (e.g., lb/MMBtu – pounds of pollutant per million British thermal units, lb/TBLS – pounds of pollutant per ton of black liquor solids, etc.). The control effectiveness evaluation was based on information provided from control technology vendors and takes the inlet pollutant loading/concentration into consideration as well as varying levels of control into account (e.g., number of ESP – electrostatic precipitator fields, scrubber flows, etc.). EPC also determined the comparable emissions reductions from options that involve improvements to existing controls or year-round operation of existing controls as a part of the control effectiveness evaluation.

Step 4 – Evaluate Impacts and Document Results.

EPC conducted an impacts analysis that is comprised of the following 2 discrete parts:

- Part 1: Cost of Compliance; and
- Part 2: Energy and Non-Air Quality Environmental Impacts.

Part 1: Cost of Compliance. EPC developed estimates of capital and operating costs based upon a combination of sources including, but not limited to, control equipment vendor quotes, USEPA control technology guideline (CTG) documents, and the Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual (USEPA 2003). When it was required, site-specific design and/or other conditions that affect the site-specific costs of a control technology were taken into account (e.g., available space for add-on controls, ducting requirements, chemical, labor, energy, and waste disposal costs, etc.) EPC calculated the average cost effectiveness which is the annualized cost of control divided by the annual emissions reductions for each technically feasible control option for each VIP. If several technically feasible control technologies were identified for the same pollutant/emission unit, then the incremental cost effectiveness was also determined.

Part 2: Energy and Non-Air Quality Environmental Impacts. Energy impacts that result in additional cost were included as a part of the cost analysis. EPC also considered potential costs associated with the disposal of solid and liquid hazardous and non-hazardous wastes (e.g., SCR spent catalyst, scrubber bleed, boiler ash, etc) generated by the operation of control devices.

Step 5 – Evaluate Visibility Impacts

The final step in the BART evaluation process is to evaluate the improvement that is predicted to result from the installation of a control technology on a BART eligible source. If the most stringent control option available is selected, the facility is not required to conduct a visibility improvement determination for the BART eligible source. If a less stringent control option is selected, a visibility modeling analysis is required to determine the improvement in visibility that would occur from controlling the specific VIP from the individual BART eligible source.

By including an assessment of the visibility impacts associated with each feasible control technology, it is possible to determine whether the application of a control will result in a perceptible change in visibility. Although a control technology may be technically feasible and cost effective, it is also possible that the application of the control technology will have little effect on improving visibility. It is not USEPA's intent to require BART controls where little or no improvement in visibility will result.

Identify BART.

EPC believes that the approach described above ensures that all BART eligible sources and retrofit control options have been identified and evaluated. For each BART eligible source at the Mill, EPC presents the BART control option by VIP. The BART summary includes EPC's justification for potential control technologies or why no control technologies are proposed.

1.4 DOCUMENT ORGANIZATION

Supporting information and the BART analysis for each BART eligible source are presented in the following sections:

- Section 2 Visibility Modeling Analysis
- Section 3 Summary of BART analysis
- Section 4 No. 8 Boiler (EGUB13)
- Section 5 No. 9 Boiler (EU9B03)
- Section 6 No. 10 Recovery Furnace (EURF15)
- Section 7 Smelt Dissolving Tank (EUST15)
- Section 8 Lime Kiln (EULK29)

2. VISIBILITY MODELING ANALYSIS

Prior to conducting the visibility modeling, EPC submitted a letter in September, 2006 to Michigan DEQ outlining the methodology that would be used in visibility modeling analyses. A copy of this letter protocol is contained in Attachment A of this report. As detailed in the visibility modeling protocol letter, procedures outlined by the Lake Michigan Air Directors Consortium for the Midwest Regional Planning Organization (Midwest RPO) in their "Single Source modeling to Support Regional Haze BART Modeling Protocol" document would be followed with one exception. The exception involved the use of background visibility data and is discussed in Section 2.1 below.

Following the visibility modeling approach outlined to Michigan DEQ, EPC conducted an initial BART exemption modeling analysis to determine if the BART eligible sources at the Mill cause or contribute to visibility impairment. EPC also conducted BART control scenario modeling for various potential retrofit control devices. A brief description of the technical approach used in the visibility modeling assessment, a discussion of the modeling information, and a presentation of the visibility modeling results are shown in the following subsections. A CD-ROM that contains all pertinent electronic files for the visibility modeling analyses is included in Attachment B.

2.1 MODELING METHODOLOGY

EPC used the CALPUFF (version 5.711a) air dispersion model to model visibility impacts at the Seney Wilderness area and Isle Royale National Park Class I area. The location of each Class I area in relation to the Escanaba Mill is provided in Figure 2-1. EPC followed the methodologies outlined in the September 2006 letter that was submitted to DEQ for all visibility modeling analyses. EPC followed the guidance found in the Midwest RPO modeling protocol, with one exception. The following summarizes the exception used by EPC:

> *The Midwest RPO provided initial guidance to use the 20% best visibility days to characterize natural background light extinction. EPC used an alternate approach for determining background light extinction values that followed existing USEPA documents as well as USEPA guidance on conduction BART visibility analyses. Specifically,*

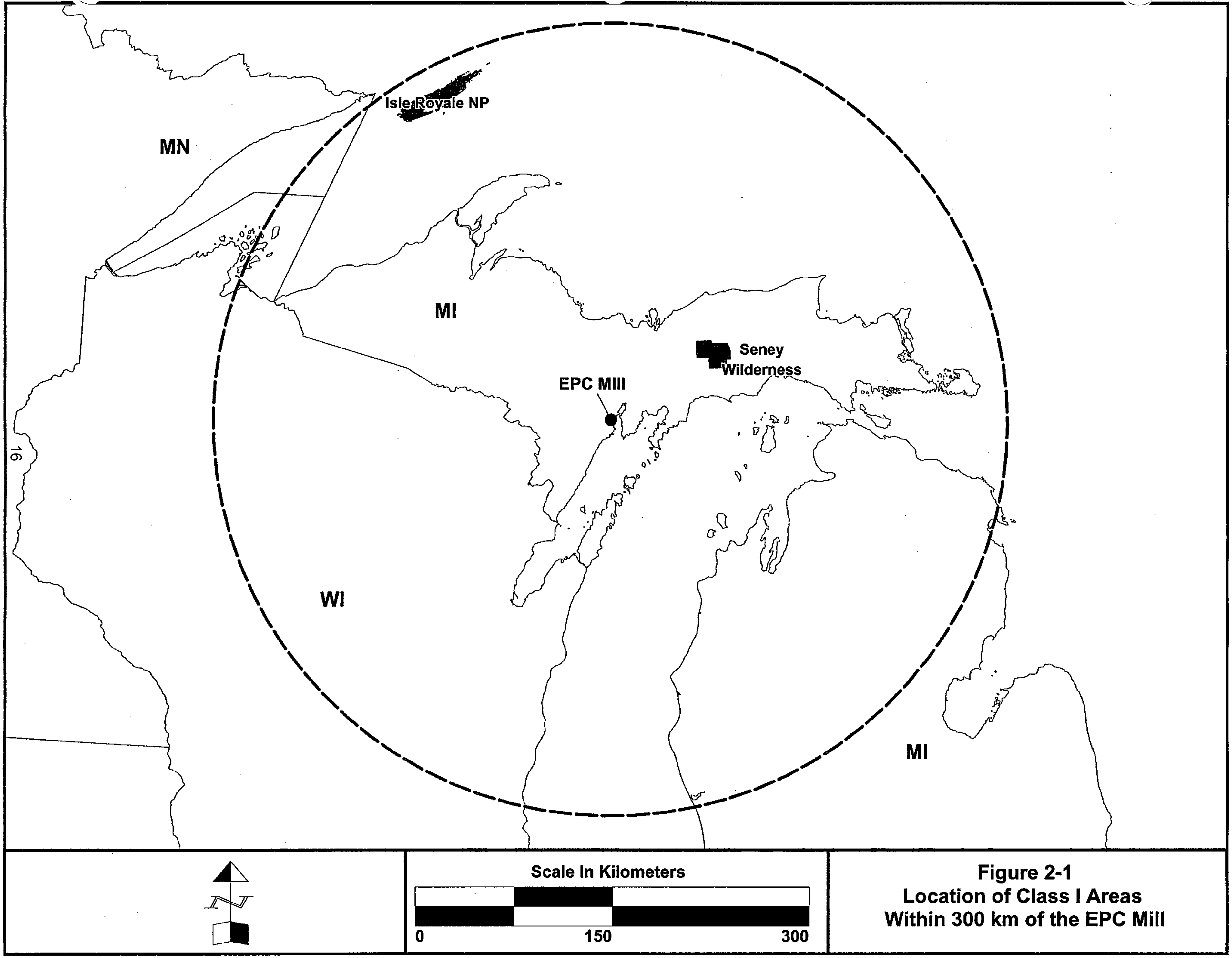

Figure 2-1
Location of Class I Areas
Within 300 km of the EPC Mill

background light extinction values were calculated using data from USEPA's "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program", (USEPA 2003a) guidance document. Average background concentrations of sulfates, nitrates, organic secondary aerosol, elemental carbon, soil, and coarse filterable particulate were taken from Table 2-1, while f[RH] factors were taken from Table A-3 of the USEPA 2003 document for each Class I area. USEPA supported the use of average light extinction values in a July 2006 memo from Joseph W. Praise, Group Leader of the Geographic Strategies Group to USEPA Region IV addressing background visibility. In the memo, USEPA clarifies that they never intended to limit States to the use of the 20% best visibility days for the purposes of determining a source's impact on visibility. The use of average light extinction values has been widely accepted by States, RPOs, USEPA regional staff, and Federal Land Managers (FLMs) in the southeastern U.S. A copy of the July 2006 memo is included as Attachment A of this report.

2.2 DECIVIEW THRESHOLD

The deciview is the metric that is used to assess the impact on visibility. The deciview represents a natural logarithmic conversion of the extinction of light caused by visibility impairing pollutants. The deciview is linked to the ability of the human eye to perceive changes in the contrast or intensity in the appearance of a visual scene. Literature (Pitchford and Malm 1994) suggests that a 1 deciview change is a "just noticeable change" for human perception. Consequently, USEPA has decided to use a value of one-half of the "just noticeable change" 1 deciview value as a safe threshold to evaluate visibility impairs that can be perceived and those that can not. This means that a 0.5 deciview change is essentially imperceptible from the background or base visibility condition.

The deciview results contained in this report have been rounded to the nearest tenth (0.1) of a deciview. The reporting of a the deciview results to the nearest tenth is consistent with the guidance provided in 40 CFR Part 51, Subpart P and the preamble to the rule.

2.3 EXEMPTION MODELING ANALYSIS

EPC conducted a visibility modeling analysis to determine if the BART eligible sources at the Mill collectively cause or contribute to visibility impairment. A 24-hr visibility change of 0.5 deciviews over average background conditions is the threshold used for assessing if a source contributes to visibility impairment in any Class I area. Following the guidance from Michigan DEQ and the Midwest RPO, a source can be exempted from a BART control analysis if the source can demonstrate through visibility modeling that the collective visibility impact from the BART eligible sources at the source do not contribute to visibility impairment in any Class I area.

EPC calculated maximum 24-hr average emission rates of VIP from the BART eligible sources at the Escanaba Mill. To calculate the emissions, the Mill used representative emission factors and typical maximum daily production data. The emission factors and production data were representative of the 2002 thru December 2006 period. These VIP emission rates were provided in the September 2006 protocol submission to Michigan DEQ, along with the assumptions and background information used in the emission rate calculations. The emission rates used in the exemption modeling analysis are shown in Table 2-1.

The results of the exemption modeling analysis at the Seney Wilderness area and Isle Royale National Park are shown in Table 2-2. The results of the exemption modeling analysis indicate that the BART eligible sources at the Escanaba Mill potentially contribute to visibility impairment in the Seney Wilderness area. No adverse visibility impacts are predicted to occur at Isle Royale National Park. Consequently, EPC must conduct a BART control analysis and model the post-control visibility impacts for the Seney Wilderness area.

2.4 BART CONTROL MODELING ANALYSIS

Since the BART eligible emissions units at the Escanaba Mill potentially contribute to visibility impairment in the Seney Wilderness area, EPC conducted multiple modeling analyses to determine the effects that add-on controls to the BART eligible emission units would have on visibility impacts at the Seney Wilderness area. To conduct the BART control technology modeling analyses, the individual impacts of each BART eligible emissions unit on the Seney Wilderness area were determined for pre-control and post-control scenarios. For these "pre-control" scenarios, the same emission rates were used for each BART eligible emissions unit as were used in the exemption modeling analysis. The results for these pre-control scenarios are shown in Table 2-3. The results of the unit by unit pre control visibility modeling analysis indicate that the No. 8 Boiler and No. 9 Boiler contribute the bulk of the visibility impacts in the Seney Wilderness area.

Table 2-1
Emissions of Visibility Impairing Pollutants
Actual Maximum 24-hr Emission Rates

Table 2-2
BART Exemption Modeling Results
Escanaba Paper Company
NewPage Corporation - Escanaba Mill

Class I Area	2002				2003				2004			
	Days over 1Δdv	Days over 0.5 Δdv	High Impact	98th Percentile Impact	Days over 1Δdv	Days over 0.5 Δdv	High Impact	98th Percentile Impact	Days over 1Δdv	Days over 0.5 Δdv	High Impact	98th Percentile Impact
Seney Wilderness	0	16	1.0	0.6	2	10	1.4	0.6	2	14	1.1	0.6
Isle Royale National Park	0	0	0.4	0.2	0	3	0.9	0.3	0	0	0.4	0.2

Table 2-3
Individul BART Eligible Emissions Impacts - Pre Controls
Escanaba Paper Company
NewPage Corporation - Escanaba Mill

	2002				2003				2004			
Seney Impacts Only	Days over 1Δdv	Days over 0.5 Δdv	High Impact	98th Percentile Impact	Days over 1Δdv	Days over 0.5 Δdv	High Impact	98th Percentile Impact	Days over 1Δdv	Days over 0.5 Δdv	High Impact	98th Percentile Impact
No. 8 Power Boiler	0	2	0.6	0.4	0	5	0.9	0.4	0	4	0.8	0.4
No. 9 Bark Boiler	0	0	0.2	0.1	0	0	0.2	0.1	0	0	0.2	0.1
No. 10 Recovery Furnace	0	0	0.2	0.1	0	0	0.3	0.1	0	0	0.2	0.1
Lime Kiln	0	0	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0
Smelt Dissolving Tank	0	0	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0

For each control technology identified in Sections 4 through 8 of this report, EPC evaluated the visibility impacts using controlled emission rates that reflect each control technology's assumed control efficiency. Only control technologies that were determined to be technically feasible were evaluated. Additionally, for BART eligible sources where post-1990 MACT or PSD BACT controls already exist, no BART visibility modeling was conducted for the VIP affected by the control. The specific justifications for all add-on control technologies shown in the following tables in this section are addressed later in this report. The following were not assessed for add-on controls in the visibility modeling:

- No. 10 Recovery Furnace – All VIP Emissions
- Lime Kiln – All VIP Emissions
- Smelt Dissolving Tank – All VIP Emissions
- All emissions of PM_{10} and $PM_{2.5}$ for all BART eligible sources.

The BART control visibility modeling was conducted on a unit by unit basis, with one modeling iteration performed for each possible control technology alone. This allowed EPC to evaluate the direct impacts that each add-on control has on modeled visibility results in the Seney Wilderness area. The assumed control efficiency of each control technology was applied to the appropriate pollutant 24-hr emission rate used for these pre-control scenarios. The emission rates used for each possible control scenario are shown in Table 2-4. Each BART eligible emissions unit's individual visibility impact on the Seney Wilderness area for each add-on control scenario is shown in Table 2-5. A comparison between the pre control and add-on control scenarios, with the resulting net visibility improvement on a highest and 98th percentile daily basis is shown in Table 2-6.

The comparison of visibility impacts between pre and post control scenarios in Table 2-6 indicates that add-on controls do not significantly affect visibility improvement from the No. 8 Boiler for either SO_2 or NO_X controls. The most stringent NO_X control of the No. 8 Boiler (90% NO_X control efficiency) causes a modeled net visibility improvement of 0.4 deciview on the worst case day in 2003. The number of days that the No. 8 Boiler contributed to visibility impairment (i.e., modeled impact over 0.5 deciview in a Class I area) over the three year modeled period (1,093 modeled days) changed from 11 days to 1 day. For the maximum SO_2

Table 2-4
Add-On Control Scenarios
Escanaba Paper Company
NewPage Corporation - Escanaba Mill

Source Name	Control Technology	Control Efficiency	Pollutant	SO_2	NO_X	Filterable $PM_{2.5\text{-}10}$	Filterable $PM_{2.5}$	Condensable PM
				g/s	g/s	g/s	g/s	g/s
No. 8 Power Boiler	Switch to Natural Gas	99%	SO_2	0.48	36.95	0.98	1.84	0.49
	Switch to No. 2 Fuel Oil	93%	SO_2	3.39	36.95	0.98	1.84	0.49
	High DP Scrubber	61%	SO_2	18.91	36.95	0.98	1.84	0.49
	Dry Scrubber/Semi-Dry Scrubber	25%	SO_2	36.36	36.95	0.98	1.84	0.49
	SCR	90%	NO_x	48.49	3.70	0.98	1.84	0.49
	Low NO_X Burners	40%	NO_x	48.49	22.17	0.98	1.84	0.49
	SNCR	20%	NO_x	48.49	29.56	0.98	1.84	0.49
	FGR	12%	NO_x	48.49	32.52	0.98	1.84	0.49
No. 9 Bark Boiler	Adding Caustic to Scrubber	50%	SO_2	0.73	9.98	0.00	5.31	0.14
	SCR	90%	NO_x	1.45	1.00	0.00	5.31	0.14
	Low NO_X Burners	40%	NO_x	1.45	5.99	0.00	5.31	0.14
	SNCR	35%	NO_x	1.45	6.49	0.00	5.31	0.14
	FGR	20%	NO_x	1.45	7.98	0.00	5.31	0.14

Note:

A 93% SO_2 control efficiency was conservatively used for the visibility modeling of the No. 8 Power Boiler No. 2 Fuel Oil control scenario although a 91% SO_2 control efficiency was used in the cost analysis. The use of the 93% control efficiency emission rate will show a greater visibility reduction than a 91% control efficiency emission rate; therefore, the dollar per deciview cost will lower (i.e., more feasible) than a 91% control efficiency and more conservative.

Table 2-5
Individul BART Eligible Emissions Impacts - Post Control Scenarios
Escanaba Paper Company
NewPage Corporation - Escanaba Mill

Source Name	Control Technology	Control Efficiency	Pollutant	2002				2003				2004			
				Days over 1Δdv	Days over 0.5 Δdv	High Impact	98th Percentile Impact	Days over 1Δdv	Days over 0.5 Δdv	High Impact	98th Percentile Impact	Days over 1Δdv	Days over 0.5 Δdv	High Impact	98th Percentile Impact
No. 8 Power Boiler	Switch to Natural Gas	99%	SO_2	0	0	0.5	0.3	0	2	0.5	0.3	0	0	0.5	0.3
	Switch to No. 2 Fuel Oil	93%	SO_2	0	1	0.5	0.3	0	2	0.6	0.3	0	0	0.5	0.3
	High DP Scrubber	61%	SO_2	0	1	0.6	0.3	0	3	0.7	0.3	0	3	0.6	0.3
	Dry Scrubber/Semi-Dry Scrubber	25%	SO_2	0	2	0.6	0.4	0	3	0.8	0.4	0	3	0.7	0.4
	SCR	90%	NO_x	0	0	0.4	0.2	0	1	0.5	0.2	0	0	0.5	0.2
	Low NO_X Burners	40%	NO_x	0	1	0.5	0.3	0	2	0.7	0.3	0	2	0.6	0.3
	SNCR	20%	NO_x	0	2	0.6	0.4	0	3	0.8	0.4	0	2	0.7	0.4
	FGR	12%	NO_x	0	2	0.6	0.4	0	3	0.9	0.4	0	4	0.7	0.4
No. 9 Bark Boiler	Adding Caustic to Scrubber	50%	SO_2	0	0	0.2	0.1	0	0	0.2	0.1	0	0	0.2	0.1
	SCR	90%	NO_x	0	0	0.1	0.1	0	0	0.1	0.1	0	0	0.1	0.1
	Low NO_X Burners	40%	NO_x	0	0	0.1	0.1	0	0	0.2	0.1	0	0	0.1	0.1
	SNCR	35%	NO_x	0	0	0.1	0.1	0	0	0.2	0.1	0	0	0.2	0.1
	FGR	20%	NO_x	0	0	0.1	0.1	0	0	0.2	0.1	0	0	0.2	0.1

Note:
A 93% SO_2 control efficiency was conservatively used for the visibility modeling of the No. 8 Power Boiler No. 2 Fuel Oil control scenario although a 91% SO_2 control efficiency was used in the cost analysis. The use of the 93% control efficiency emission rate will show a greater visibility reduction than a 91% control efficiency emission rate; therefore, the dollar per deciview cost will lower (i.e., more feasible) than a 91% control efficiency and more conservative.

Table 2-6
Comparison of Annual Highest and 98th Percentile Daily Visibility Impacts
Escanaba Paper Company
NewPage Corporation - Escanaba Mill

Source Name	Control Technology	Control Efficiency	Pollutant	2002 Change in High Impact	2002 Change in 98th Percentile Impact	2003 Change in High Impact	2003 Change in 98th Percentile Impact	2004 Change in High Impact	2004 Change in 98th Percentile Impact
No. 8 Power Boiler	Switch to Natural Gas	99%	SO_2	0.1	0.2	0.4	0.2	0.3	0.2
	Switch to No. 2 Fuel Oil	93%	SO_2	0.1	0.1	0.4	0.2	0.3	0.2
	High DP Scrubber	61%	SO_2	0.1	0.1	0.2	0.1	0.2	0.1
	Dry Scrubber/Semi-Dry Scrubber	25%	SO_2	0.0	0.1	0.1	0.0	0.1	0.0
	SCR	90%	NO_x	0.2	0.3	0.4	0.2	0.3	0.2
	Low NO_X Burners	40%	NO_x	0.1	0.1	0.2	0.1	0.1	0.1
	SNCR	20%	NO_x	0.1	0.1	0.1	0.1	0.1	0.1
	FGR	12%	NO_x	0.0	0.0	0.1	0.0	0.0	0.0
No. 9 Bark Boiler	Adding Caustic to Scrubber	50%	SO_2	0.0	0.0	0.0	0.0	0.0	0.0
	SCR	90%	NO_x	0.1	0.1	0.1	0.0	0.1	0.1
	Low NO_X Burners	40%	NO_x	0.0	0.0	0.1	0.0	0.0	0.0
	SNCR	35%	NO_x	0.0	0.0	0.1	0.0	0.0	0.0
	FGR	20%	NO_x	0.0	0.0	0.0	0.0	0.0	0.0

Note:
A 93% SO_2 control efficiency was conservatively used for the visibility modeling of the No. 8 Power Boiler No. 2 Fuel Oil control scenario although a 91% SO_2 control efficiency was used in the cost analysis. The use of the 93% control efficiency emission rate will show a greater visibility reduction than a 91% control efficiency emission rate; therefore, the dollar per deciview cost will lower (i.e., more feasible) than a 91% control efficiency and more conservative.

control (99% control efficiency with natural gas firing), the greatest visibility improvement is 0.4 deciview with a reduction in days over 0.5 deciview dropping from 11 to 2. EPC does not believe that the magnitude and frequency of visibility improvement in the Seney Wilderness due to add-on controls for the No. 8 Boiler is significant.

As with the No. 8 Boiler, the comparison of visibility impacts between pre and post SO_2 and NO_X control scenarios in Table 2-6 indicates that add-on controls do not significantly affect visibility improvement from the No. 9 Boiler. The most stringent NO_X control for the No. 9 Boiler (90% NO_X control efficiency) causes a modeled net visibility improvement of 0.1 deciview on the worst case day in 2003. The number of days that the No. 9 Boiler contributed to visibility impairment (i.e., modeled impact over 0.5 deciview in a Class I area) over the three year modeled period (1,093 modeled days) is 0 days. For the maximum SO_2 control (50% control efficiency with the addition of more caustic scrubbing), there is no modeled change in visibility. The SO_2 emissions from the No. 9 Bark Boiler are so low that no initial visibility impact was predicted from the pre-control scenario. EPC does not believe that the magnitude and frequency of visibility improvement in the Seney Wilderness due to add-on controls for the No. 9 Boiler is significant.

The following sections of this report reference the visibility modeling results presented in this section, as well as address the other factors for applying BART (e.g., cost and technical feasibility of controls).

3. SUMMARY OF BART ANALYSIS RESULTS

The results of the BART analysis are provided in full detail in subsequent sections of this document. EPC has included this section as a brief summary to discuss the results of the BART analysis.

Summaries of the BART results for each of the facility's BART eligible sources (No. 8 Boiler, No. 9 Boiler, Recovery Furnace, Smelt Dissolving Tank, and Lime Kiln) are provided in Tables 3-1, 3-2, 3-3, 3-4, and 3-5 respectively. The tables include the following information:

- VIPs identified for each source;
- Identification of control technologies for each source/VIP scenario;
- Control effectiveness of each technically feasible control technology;
- Calculated Cost Effectiveness;
- Energy and non-air quality environmental impacts;
- Visibility impacts of control technology; and
- Identification of BART control.
- The tables identify "N/A" in places where the previous step in the BART analysis indicated that the evaluation of the next BART evaluation step was not warranted. For example, if a control technology evaluation was determined to be unnecessary due to existing Maximum Available Control Technology (MACT), then the subsequent BART evaluation steps were determined to be "N/A". Additionally, if a potential control technology was considered not to be cost effective, then energy and visibility impacts were determined to be "N/A" as well.

As indicated in Section 2, only the Seney Wilderness Area is predicted to have any visibility impacts due to the BART-eligible sources at the Mill. A summary comparison of the visibility impacts on the Seney Wilderness Area considering the pre-control and post-control scenarios is provided in Table 3-6. EPC used the 98th Percentile deciview values for the pre-control and

Table 3-1
Summary of BART Analysis for the No. 8 Boiler

VIP	Identification of Control Technologies	Control Effectiveness	Cost Effectiveness ($/ton removed)	Energy and Other Impacts	Visibility Impacts	BART Determination
No. 8 Boiler (EU8B13) – Fires No. 6 fuel oil and natural gas. Controls include Flue Gas Recirculation combustion control, which is operated only during the ozone control season. The source is subject to 40 CFR 63, Subpart DDDDD (Boiler MACT).						
NO_x	Selective Catalytic Reduction Low NOx Burners Selective Non-Catalytic Reduction Combustion Controls	90% 40% 20% [a]	$15,500 $3,600 $43,100 $44,600	N/A[b] Negligible N/A[b] N/A[b]	N/A[b] 0.2 N/A[b] N/A[b]	Continued use of the existing FGR system only during the ozone control season.
SO_2	Low Sulfur Fuels (Natural Gas Only) Low Sulfur Fuels (No. 2 Fuel Oil Only) Wet Scrubbing Dry Scrubbing Semi-Dry Scrubbing	99% 91% 61% 25% 25%	$4,200 $39,400 $30,900 $129,400 $118,800	Negligible N/A[b] N/A[b] N/A[b] N/A[b]	0.4 N/A[b] N/A[b] N/A[b] N/A[b]	No add-on controls.
PM_{10}	N/A[c]	N/A[c]	N/A[c]	N/A[c]	N/A[c]	The No. 8 Boiler is subject to 40 CFR 63, Subpart DDDDD (Boiler MACT). Boiler MACT does not require add-on controls in order to meet the emission limitations for liquid and gas fuel fired units; therefore, the existing control technology represents a MACT and BART level of control.

[a] Combustion controls are already installed on the No. 8 Boiler. The No. 8 Boiler is equipped with an Induced Flue Gas Recirculation (FGR) system that is operated only during the ozone control season. EPC evaluated the utilization of FGR on a year-round basis for the BART analysis.
[b] Energy and Other Impacts as well as Visibility Impacts were evaluated only for control technologies that could potentially be considered cost effective.
[c] The unit is subject to a MACT standard which represents a BART level of control. Therefore, no further evaluation was warranted for this pollutant.

Table 3-2
Summary of BART Analysis for the No. 9 Boiler

VIP	Identification of Control Technologies	Control Effective -ness	Cost Effectiveness ($/ton removed)	Energy and Other Impacts	Visibility Impacts	BART Determination
No. 9 Boiler (EU9B03) – Fires bark and natural gas. Controls include Overfire Air combustion control, use of low sulfur fuels, and wet scrubbing. The source is subject to 40 CFR 63, Subpart DDDDD (Boiler MACT).						
NO_x	Selective Catalytic Reduction Low NOx Burners Selective Non-Catalytic Reduction Combustion Controls	90% 40% 35% 20%[a]	$13,800 $18,900 $10,700 $19,200	N/A[b] N/A[b] N/A[b] N/A[b]	N/A[b] N/A[b] N/A[b] N/A[b]	Use of the existing overfire air combustion control system.
SO_2	Wet Scrubbing (addition of caustic) Low Sulfur Fuels Dry Scrubbing Semi-Dry Scrubbing	50%[c] [d] [e] [f]	$21,800 N/A[d] N/A[e] N/A[f]	N/A[b] N/A[d] N/A[e] N/A[f]	N/A[b] N/A[d] N/A[e] N/A[f]	Use of existing low sulfur fuels.
PM_{10}	N/A[g]	N/A[g]	N/A[g]	N/A[g]	N/A[g]	The No. 9 Boiler is subject to 40 CFR 63, Subpart DDDDD (Boiler MACT). The existing wet scrubber control technology represents a MACT and BART level of control.

[a] Combustion controls (Overfire Air) are already installed on the No. 9 Boiler. The use of this type of control is reflected in baseline emission estimates. EPC evaluated the use of FGR for the BART analysis, which is expected to reduce NO_x by no more than 20%. The use of FGR on the No. 9 Boiler would result in a minimal reduction in NO_x and would increase emissions of other pollutants that are affected by incomplete combustion. Other pollutants expected to experience an increase include carbon monoxide, toxic air contaminants, hazardous air pollutants, and other organics.
[b] Energy and Other Impacts as well as Visibility Impacts were evaluated only for control technologies that could potentially be considered cost effective.
[c] Wet scrubbing is already installed on the No. 9 Boiler. EPC evaluated the utilization of caustic (instead of only water) scrubbing solution on the existing scrubber for the BART analysis.
[d] Low sulfur fuels are already in use on the No. 9 Boiler. The use of this type of control is reflected in baseline emission estimates and no further evaluation was performed.
[e] Dry scrubber vendors were unable to guarantee any removal efficiency for the No. 9 Boiler. As a result, the control technology was determined to be technically infeasible and no further evaluation was performed.
[f] Semi-Dry scrubber vendors were unable to guarantee any removal efficiency for the No. 9 Boiler. As a result, the control technology was determined to be technically infeasible and no further evaluation was performed.
[g] The unit is subject to a MACT standard which represents a BART level of control. Therefore, no further evaluation was warranted for this pollutant.

Table 3-3
Summary of BART Analysis for the No. 10 Recovery Furnace

VIP	Identification of Control Technologies	Control Effective -ness	Cost Effective-ness ($/ton removed)	Energy and Other Impacts	Visibility Impacts	BART Determination
No. 10 Recovery Furnace (EURF15) – Fires black liquor solids. Burns No. 6 fuel oil and/or natural gas for startup and shutdown. High Volume Low Concentration non-condensable gases are also combusted in the unit. Controls include staged combustion air and an electrostatic precipitator. The source is subject to 40 CFR 63, Subpart MM (MACT II).						
NO_x	Selective Catalytic Reduction	[a]	N/A[a]	N/A[a]	N/A[a]	Use of the existing staged combustion air system.
	Low NOx Burners	[b]	N/A[b]	N/A[b]	N/A[b]	
	Selective Non-Catalytic Reduction	[b]	N/A[b]	N/A[b]	N/A[b]	
	Combustion Control Methods	[b]	N/A[b]	N/A[b]	N/A[b]	
SO_2 30	Wet Scrubbing	[c]	N/A[c]	N/A[c]	N/A[c]	No additional controls.
	Dry Scrubbing	[d]	N/A[d]	N/A[d]	N/A[d]	
	Semi-Dry Scrubbing	[e]	N/A[e]	N/A[e]	N/A[e]	
	Low Sulfur Fuels (startup/shutdown)	91%[e]	$47,500	N/A[f]	N/A[f]	
PM_{10}	N/A[g]	N/A[g]	N/A[g]	N/A[g]	N/A[g]	The No. 10 Recovery Furnace is subject to 40 CFR 63, Subpart MM (MACT II). The existing ESP control technology represents a MACT and BART level of control.

[a] SCR, Low NO_x Burners, and SCR control technologies have not been installed on a recovery furnace. As a result, these control technologies were determined to be technically infeasible and were not further evaluated.

[b] Combustion control methods (staged combustion air) is already installed on the No. 10 Recovery Furnace. The use of this type of control is reflected in baseline emission estimates. FGR control technology has not been installed on a recovery furnace and was determined to be technically infeasible and was not further evaluated.

[c] Emissions of sulfur dioxide during normal operation while firing black liquor solids are less than 8 tons per year. Wet scrubber vendors were unable to guarantee any removal efficiency. As a result, the control technology was determined to be technically infeasible and was not further evaluated.

[d] Dry Scrubbing and Semi-Dry Scrubbing control technologies have not been installed on a recovery furnace. This fact, in conjunction with the low emissions experienced during normal operation result in a determination that the control technology is not technically feasible and was not further evaluated.

[e] Lower sulfur fuels can be utilized on startup and shutdown. EPC evaluated switching from No. 6 fuel oil to No. 2 fuel oil or natural gas. The specialized application and necessary location of additional natural gas burners in the No. 10 Recovery Furnace cannot be accommodated due to space constraints. As a result, the control technology was determined to be technically infeasible and was not further evaluated. Switching to No. 2 fuel oil could result in up to a 91% removal efficiency for SO2 during startup and shutdown conditions.

[f] Energy and Other Impacts as well as Visibility Impacts were evaluated only for control technologies that could potentially be considered cost effective.

[g] The unit is subject to a MACT standard which represents a BART level of control. Therefore, no further evaluation was warranted for this pollutant.

Table 3-4
Summary of BART Analysis for the Smelt Dissolving Tank

VIP	Identification of Control Technologies	Control Effective-ness	Cost Effectiveness ($/ton removed)	Energy and Other Impacts	Visibility Impacts	BART Determination
Smelt Dissolving Tank (EUST15) – Receives smelt from the Recovery Furnace and dissolves the material in caustic to create green liquor. This is not a combustion source. Controls include a wet scrubber. The source is subject to 40 CFR 63, Subpart MM (MACT II).						
SO_2	Wet Scrubbing Dry Scrubbing Semi-Dry Scrubbing	[a] [b] [c]	N/A[a] N/A[b] N/A[c]	N/A[a] N/A[b] N/A[c]	N/A[a] N/A[b] N/A[c]	No additional controls.
PM_{10}	N/A[c]	N/A[c]	N/A[c]	N/A[c]	N/A[c]	The No. 10 Recovery Furnace is subject to 40 CFR 63, Subpart MM (MACT II). The existing wet scrubber control technology represents a MACT and BART level of control.

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[a] Wet scrubbing, using weak wash as a scrubbing solution, is already installed on the Smelt Dissolving Tank. The use of this type of control is reflected in baseline emission estimates and was not further evaluated.
[b] Dry Scrubbing and Semi-Dry Scrubbing control technologies have not been installed on a smelt dissolving tank. This fact, in conjunction with the low emissions result in a determination that the control technology is not technically feasible and was not further evaluated.
[c] The unit is subject to a MACT standard which represents a BART level of control. Therefore, no further evaluation was warranted for this pollutant.

Table 3-5
Summary of BART Analysis for the Lime Kiln

VIP	Identification of Control Technologies	Control Effective-ness	Cost Effectiveness ($/ton removed)	Energy and Other Impacts	Visibility Impacts	BART Determination
Lime Kiln (EULK29) – Converts calcium carbonate to calcium oxide under high heat conditions. Fires No. 6 fuel oil and/or natural gas to achieve heat requirements. Low Volume High Concentration non-condensable gases are also combusted in the unit as a back-up control device. Controls include Low NOx technology (i.e. good combustion control) and wet scrubbing. The source is subject to 40 CFR 63, Subpart MM (MACT II).						
NO_x	Selective Catalytic Reduction Selective Non-Catalytic Reduction Low NOx Burner Technology	[a] [b] [b]	N/A[a] N/A[b] N/A[b]	N/A[a] N/A[b] N/A[b]	N/A[a] N/A[b] N/A[b]	Use of the existing Low NO_x Burner Technology (passive combustion control methodology).
SO_2	Wet Scrubbing Dry Scrubbing Semi-Dry Scrubbing	[c] [d] [e]	N/A[c] N/A[d] N/A[e]	N/A[c] N/A[d] N/A[e]	N/A[c] N/A[d] N/A[e]	Use of the existing venturi scrubber with weak wash and/or caustic as a scrubbing medium.
PM_{10}	N/A[e]	N/A[e]	N/A[e]	N/A[e]	N/A[e]	The Lime Kiln is subject to 40 CFR 63, Subpart MM (MACT II). The existing venturi scrubber represents a MACT and BART level of control.

[a] SCR and Selective Non-Catalytic Reduction control technologies have not been installed on a lime kiln. Therefore, a determination was made that these control technologies are not technically feasible and were not further evaluated.
[b] Lime kiln burner vendors have indicated that Low NO_x Burners cannot be installed on a lime kiln. The flame length for a lime kiln is already very long (>8 feet in length). It is possible to optimize lime kiln burners to minimize NO_x formation, and vendors refer to this as Low NOx burner technology, which is another way of describing good combustion control. EPC optimized the burner recently and utilizes good combustion control to minimize NOx emissions from this source and was not further evaluated.
[c] Venturi scrubbing, using weak wash and/or caustic as a scrubbing solution, is already installed on the Lime Kiln. The use of this type of control is reflected in baseline emission estimates and was not further evaluated.
[d] Dry Scrubbing and Semi-Dry Scrubbing control technologies have not been installed on a lime kiln. This fact, in conjunction with the low emissions (<5 tons per year) result in a determination that the control technology is not technically feasible and was not further evaluated.
[e] The unit is subject to a MACT standard which represents a BART level of control. Therefore, no further evaluation was warranted for this pollutant.

Table 3-6
Comparison of Pre and Post-Control 98th Percentile Visibility Impacts
Escanaba Paper Company
NewPage Corporation - Escanaba Mill

Source Name	Control Technology	Control Efficiency	Pollutant	2002 98th Percentile Impact	2003 98th Percentile Impact	2004 98th Percentile Impact
No. 8 Power Boiler	Base Case Scenario			0.4	0.4	0.4
No. 8 Power Boiler	Switch to Natural Gas	99%	SO_2	0.3	0.3	0.3
	Switch to No. 2 Fuel Oil	93%	SO_2	0.3	0.3	0.3
	High DP Scrubber	61%	SO_2	0.3	0.3	0.3
	Dry Scrubber/Semi-Dry Scrubber	25%	SO_2	0.4	0.4	0.4
	SCR	90%	NO_x	0.2	0.2	0.2
	Low NO_X Burners	40%	NO_x	0.3	0.3	0.3
	SNCR	20%	NO_x	0.4	0.4	0.4
	FGR	12%	NO_x	0.4	0.4	0.4
No. 9 Bark Boiler	Base Case Scenario			0.1	0.1	0.1
No. 9 Bark Boiler	Adding Caustic to Scrubber	50%	SO_2	0.1	0.1	0.1
	SCR	90%	NO_x	0.1	0.1	0.1
	Low NO_X Burners	40%	NO_x	0.1	0.1	0.1
	SNCR	35%	NO_x	0.1	0.1	0.1
	FGR	20%	NO_x	0.1	0.1	0.1

Note:
A 93% SO_2 control efficiency was conservatively used for the visibility modeling of the No. 8 Power Boiler No. 2 Fuel Oil control scenario although a 91% SO_2 control efficiency was used in the cost analysis. The use of the 93% control efficiency emission rate will show a greater visibility reduction than a 91% control efficiency emission rate; therefore, the dollar per deciview cost will lower (i.e., more feasible) than a 91% control efficiency and more conservative.

post-control scenarios for each BART eligible source as outlined in 40 CFR Part 51, Appendix Y. The purpose of this table is to highlight the visibility impacts for each BART eligible source during the baseline or pre-control period and to compare these values with the visibility impacts for the proposed post-control scenario. This comparison provides support as to the benefit that the BART analysis has on visibility impacts caused by the BART eligible sources. EPC performed this analysis for the Seney Wilderness Area only since the BART exemption modeling indicated that EPC did not cause or contribute visibility impacts of greater than 0.5 deciviews on a 98th percentile basis at Isle Royale National Park.

4. NO. 8 BOILER (EU8B13)

The following subsections describe the No. 8 Boiler and its BART analysis for each VIP. The BART analysis includes identification of all available retrofit control technologies, discussion of technical feasibility, control effectiveness, economic impacts, environmental impacts, visibility impacts, and a final BART determination.

4.1 NO. 8 BOILER DESCRIPTION

The No. 8 Boiler is a Combustion Engineering boiler rated for 450,000 pounds of steam per hour that provides steam for mill processes and steam turbine-generator sets for producing electricity. The No. 8 Boiler burns natural gas and No. 6 fuel oil and is operated as a swing boiler.

The products of combustion (flue gases) are pulled up through the furnace, over the superheater tubes, through the generating section and out of the boiler by the induced draft (ID) fan. The heat generated by the combustion of the fuel transfers to the furnace walls, the tubes of the superheater, and the generating section of the boiler by radiation and convection. The ID fan maintains a constant, slightly negative pressure (draft) in the furnace by drawing out the combustion gases as they are created. The ID fan discharges these gases to a duct that leads to the stack and are then released to atmosphere. A portion of the flue gases are collected and re-routed back to the combustion air system through the use of an Induced Flue Gas Recirculation (IFGR or FGR) system in order to minimize NO_X emissions during the ozone control season.

The No. 8 Boiler emits the following VIPs that require a BART analysis: SO_2, NO_X, and PM_{10}. The BART analysis for each pollutant is provided below.

4.2 NO_X BART ANALYSIS

Nitrogen oxides are produced in the No. 8 Boiler several different ways. Nitrogen oxides form in the combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the No. 8 Boiler. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time.

Flame temperature is dependent upon the ratio of fuel burned to the amount of fuel that consumes all of the available oxygen.

Maintaining a low air to fuel ratio (i.e., lean combustion), reduces the potential for Thermal NOx formation because the flame temperature is lowered. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to Overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. The NO_X formed from the fuels combusted in the No. 8 Boiler is a combination of both Thermal NO_X and Fuel NO_X. A top down analysis to determine the best available NO_X control technology is provided in the following subsections.

4.2.1 Identification of All Available Retrofit Control Technologies (Step 1)

Based on the data review process described previously, a list of potential technologies for controlling NO_X emissions from No. 8 Boiler was formulated. EPC identified the following potential control technologies:

- Selective Catalytic Reduction (SCR);
- Low NO_X Burners (LNB);
- Selective Non-catalytic Reduction (SNCR); and
- Combustion Control Methods.

4.2.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down BART analysis is an evaluation of the technical feasibility of each of the identified control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility with respect to the No. 8 Boiler.

4.2.2.1 Selective Catalytic Reduction (SCR)

SCR involves the injection of ammonia upstream of a catalyst bed. Ammonia reacts with NO_X in the presence of a catalyst to form molecular nitrogen and water. One of the variables affecting NO_X reduction with SCR systems is exhaust gas temperature. The greatest NO_X reduction occurs within a temperature "window" of 600 to 750°F for conventional (vanadium- or titanium-based) catalysts. A given catalyst type exhibits optimum performance when the temperature of the exhaust gas stream is near the midpoint of the reaction temperature window for applications and where exhaust gas oxygen concentrations are greater than 1 percent. Below this optimum temperature range, the catalyst activity is greatly reduced, allowing unreacted ammonia (referred to as ammonia slip) to be emitted directly to the atmosphere.

The most effective operation of an SCR system requires stable exhaust gas flow rates, NO_X concentrations, and exhaust gas temperature. In boilers with load swings, like the No. 8 Boiler, the temperature of the flue gas is not constant and can contribute to ammonia slip. However, after discussing this issue with SCR vendors, one company proposed a SCR system and indicated a potential control efficiency of up to 90% for the No. 8 Boiler. <u>As a result, EPC considers SCR to be a technically feasible NO_X control technology.</u>

4.2.2.2 Low NO_X Burners

LNB are designed to provide a stable flame. The most common LNB technologies consist of multiple combustion zones that entail a primary combustion zone, a secondary combustion zone where additional fuel is added to chemically reduce NO_X, and a tertiary combustion zone where a low excess air environment exists to reduce the temperature and to reduce the formation of Thermal NO_X.

EPC evaluated the potential installation of LNB on the No. 8 Boiler in 2003 as part of an engineering study to determine the most cost effective means of NO_X reductions in order to comply with a state NO_X rule (R336.1801). As part of that evaluation, EPC obtained information from a LNB vendor that estimated a 40% NO_X removal efficiency. <u>As a result, the potential application of LNB on the No. 8 Boiler is considered to be technically feasible.</u>

4.2.2.3 Selective Non-Catalytic Reduction (SNCR)

The SNCR process involves the injection of a nitrogen-containing chemical, typically either ammonia or urea into a turbulent region of the boiler where the gas temperature is in the range of approximately 1600° to 2100°F with a corresponding residence time of at least 1 second. In this temperature range or "window," the injected chemical reacts selectively with NO_X in the presence of oxygen to form molecular nitrogen, carbon dioxide and water without a catalytic converter.

The primary SNCR process by-products are NH_3, CO_2, and N_2O emissions. N_2O and CO_2 are both greenhouse gases. If N_2O and CO_2 emissions need to be abated, this will affect the choice of SNCR chemical, but not necessarily the NO_X reduction performance of the SNCR system. However, with either SNCR chemical, by-product NH_3 (i.e., ammonia slip) can lead to adverse impacts downstream of the SNCR system, including air heater fouling, and plume formation. When assessing SNCR feasibility, these impacts must be considered, along with any regulatory requirements to limit NH_3 emissions.

EPC spoke with one vendor that indicated SNCR can be applied to an oil/gas-fired boiler that swings load. On a swing boiler, like the No. 8 Boiler, the application of SNCR will depend on how fast the boiler swings and how fast the temperature zone moves. Conventional SNCR dictates that urea be applied at varying boiler loads in three different zones. Newer SNCR technology can be designed with nozzles that tilt up and down to inject the urea.

NO_X reductions range from 20 to 50% at full load, depending on a variety of interdependent, unit-specific boiler and process parameters. These include:

- Physical locations of the temperature window, which moves as a function of boiler operating variables;
- Residence time of injected chemical in the temperature window;
- Initial NO_X level;
- SNCR chemical type;
- Injection-system design; and

- Allowable/acceptable levels of by-product concentrations in the flue gas.

The vendor contacted by EPC would not guarantee a NO_X removal efficiency of greater than 20%. However, the potential application of SNCR on the No. 8 Boiler is considered to be technically feasible.

4.2.2.4 Combustion Control Methods

Combustion control methods encompass a variety of design and operating features including low excess air, Overfire Air (OFA), and Flue Gas Recirculation (FGR). The No. 8 Boiler is already equipped with a FGR system that is used only during the ozone season.

OFA serves to minimize NO_X emissions through staged combustion. Staged combustion consists of injecting a portion of the combustion air downstream of the fuel-rich primary combustion zone. The object is to achieve a fuel-rich flame zone followed by an air-rich secondary zone where combustion is completed. This reduces the amount of oxygen for conversion with fuel-bound nitrogen and reduces thermal NO_X by lowering the peak temperatures in the primary combustion zone. It is not technically feasible to apply OFA to a gas/oil-fired boiler such as the No. 8 Boiler.

EPC believes that other combustion controls are technically feasible for the No. 8 Boiler and has already incorporated FGR into the existing design of the unit.

4.2.3 Evaluate Control Effectiveness of Remaining Technically Feasible Control Technologies (Step 3)

Based on the reasons outlined in the above discussion, EPC has identified the following control technologies as technically feasible, ranked in order of most effective to least effective:

- SCR – 90% control;
- LNB – 40% control;
- SNCR – 20% control; and
- Combustion Control Methods – Already in place through the use of the existing FGR system which is operated during the ozone control season. Year-round operation of

the FGR system does not appear to provide substantial reductions. EPC evaluated this technology by reviewing actual CEMS data and determined that this option would not result in any more than 12% control over the current baseline emissions.

4.2.4 Evaluate Impacts and Document Results (Step 4)

The following evaluation considers the economic, energy, and environmental impacts of applying SCR, LNB, or SNCR control technologies to the No. 8 Boiler for NO_X control. EPC also evaluated the use of the existing FGR system year-round.

4.2.4.1 Economic Impacts of Control Technologies

The No. 8 Boiler is located in an area where there is not room for expansion, making installation of large add-on control technologies difficult. In order to accommodate some of the large equipment installations, EPC estimated installation costs to elevate equipment on catwalks. Since the No. 8 Boiler is ID fan limited, several of the add-on control technology installations would also require the purchase and installation of additional fan capacity. Additionally, the existing stack would not be adequate following the installation of several of the add-on control technology installations and EPC estimated the costs associated with replacement of the stack in these circumstances.

A summary of the economic impact analysis for the technically feasible control technologies is provided in Table 4-1. EPC followed the guidance and procedures outlined in 40 CFR Part 51, Appendix Y and the *OAQPS Air Pollution Cost Control Manual.* Supporting cost evaluation spreadsheets are provided in Attachment C, Table Nos. C-1, C-2, C-3, and C-4.

4.2.4.2 Energy and Environmental Impacts of Control Technologies

If SCR were installed on the No. 8 Boiler, there would not be substantial energy impacts. However, the utilization of SCR could contribute to environmental impacts associated with the addition of NH_3 and greenhouse gas emissions of N_2O and CO_2 which would be formed as

Table 4-1
Summary of Economic Impact Analysis – No. 8 Boiler NO_x Controls

Control Technology	Baseline Emission Rate (TPY)	Emissions Performance Level	Expected Emissions Reductions (TPY)	Summary of Costs
SCR[a]	143.2	90%	128.9	Total Annualized Cost: $2,001,500 Average Cost Effectiveness: $15,500/ton Average Cost Effectiveness: $6,671,667/dv
LNB[a]	143.2	40%	57.3	Total Annualized Cost: $204,000 Average Cost Effectiveness: $3,600/ton Average Cost Effectiveness: $2,040,000/dv
SNCR[a]	143.2	20%	28.6	Total Annualized Cost: $1,235,200 Average Cost Effectiveness: $43,100/ton Average Cost Effectiveness: $12,352,000/dv
FGR Year-Round Operation	131.6	12%	15.8	Total Annualized Cost: $706,600 Average Cost Effectiveness: $44,600/ton Average Cost Effectiveness: $7,066,000/dv

[a] Costs were evaluated conservatively using a baseline emission rate that is associated without operation of the existing FGR system.

byproducts of the SCR process. If the temperature of the flue gases was not maintained within the optimum range, ammonia could be emitted (ammonia slip). The negative impacts of ammonia slip include:

- Detectable odor at levels of > 5 ppm;
- Health concern at levels of > 25 ppm;
- Stack plume visibility issue by the formation of ammonia chlorides (when the fuels being burned contain chlorine compounds);
- Ammonia-sulfur compound formation when burning sulfur-containing fuels that can plug, foul, and corrode downstream equipment; and
- Possible implications to the Mill's Chemical Accident Prevention Provisions applicability and/or plan.

If LNB were installed on the No. 8 Boiler, there would be a reduction in energy efficiency related to the burner design and tuning in order to optimize the combustion characteristics and reduce the formation of NO_X. There are no negative environmental impacts associated with using LNB.

If SNCR were installed on the No. 8 Boiler, there would be a reduction in energy efficiency as a result of the reduction reaction using thermal energy from the boiler, thus reducing the energy available for power (or heat) generation. The increase in fuel usage that is attributed to this reduction in energy efficiency in considered in the Total Annual Costs presented for the SNCR analysis. In addition to the energy impacts due to the application of SNCR, there are environmental impacts that are associated with the addition of urea and the resultant decomposition to NH_3 and the greenhouse gas emissions of N_2O and CO_2. Typical SNCR operation requires more reagent (i.e., urea) be injected than required by the theoretical stoichiometric ratios. In addition, the NO_X removal efficiency would be only 20%, which would leave a large portion of the urea reagent unreacted. Since the No. 8 Boiler is a swing load boiler, there could be wide temperature swings that could contribute to ammonia slip.

If FGR were operated on the No. 8 Boiler year-round, there would not be substantial energy or any other negative environmental impacts.

4.2.5 Evaluate Visibility Impacts (Step 5)

40 CFR Part 51, Appendix Y provides limited guidance on how to evaluate the visibility impacts of the pre- and post-control modeling results. Appendix Y does provide the following two suggestions for making determinations:

- Evaluate a net visibility improvement determination; and
- Compare the 98th percentile days for the pre and post control runs.

Evaluate a net visibility improvement determination

The BART Control Modeling analysis is provided in Section 2 of this document. The modeled changes in visibility in the Seney Wilderness due to the addition of add-on NO_X control to the No. 8 Boiler can be summarized through the following relationships:

- Table 2-3 of this report shows that without add-on NO_X control, there are 11 days over the 0.5 deciview "contribute to visibility impairment" threshold over the three year modeled period (1,093 days).
- With the addition of low NO_X burners as add-on control, 5 days are over the 0.5 deciview threshold over the three year modeled period. If SCR is applied to the No. 8 Boiler, 1 day is over the 0.5 deciview threshold.
- As shown in Table 2-6 of this report, the difference between the maximum 24-hr visibility improvement realized from the addition of SCR is only 0.2 deciview greater than the addition of Low NOX Burners.
- The net maximum 24-hr visibility improvement realized for the addition of SNCR is only 0.1 deciview.

Compare the 98th percentile days for the pre and post control runs

Table 2-6 of this report shows the net visibility change to the 98th percentile daily impacts per modeled year for each of the technically feasible control technologies. The highest change in 98th percentile visibility impact for each control technology is shown below:

- SCR – 0.3 deciview
- Low NO_X Burners – 0.1 deciview

- SNCR – 0.1 deciview
- FGR – 0.1 deciview

4.2.6 Identify BART

Based on the information developed in the Impacts Analysis, BART for NO_X from the No. 8 Boiler is identified as use of the existing FGR system during the ozone control season only.

4.3 SO_2 BART ANALYSIS

Sulfur dioxide (SO_2) emissions from the No. 8 Boiler are largely the result of the combustion of No. 6 fuel oil due to the oxidation of sulfur in the fuel to SO_2. Natural gas combustion contributes negligible quantities of SO_2.

4.3.1 Identification of All Available Retrofit Control Technologies (Step 1)

Based on the data review process described previously, a list of potential technologies for controlling SO_2 emissions from No. 8 Boiler was formulated. EPC identified the following potential control technologies:

- Low Sulfur Fuels;
- Wet Scrubbing;
- Dry Scrubbing; and
- Semi-Dry Scrubbing.

4.3.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down BART analysis is an evaluation of the technical feasibility of each of the identified control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility with respect to the No. 8 Boiler.

4.3.2.1 Low Sulfur Fuels

In addition to natural gas, the No. 8 Boiler is permitted to burn No. 6 fuel oil with a sulfur content of 1.0%. Baseline SO_2 emissions are approximately 115 tpy, which are driven by the combustion of fuel oil (114.4 tons from fuel oil combustion, and 0.3 tons from natural gas combustion). Therefore, SO_2 emissions can be influenced by combusting only natural gas and/or switching from No. 6 fuel oil to a lower sulfur containing No. 2 fuel oil. <u>EPC considers the substitution of natural gas for the No. 6 fuel oil to be a technically feasible alternative and also considers the use of lower sulfur containing No. 2 fuel oil to be a technically feasible alternative.</u>

4.3.2.2 Wet Scrubbing

Wet caustic scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For acid gas control, the absorption process is chemical-based and uses a caustic solution (i.e., sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Wet caustic scrubbers may take the form of a variety of different configurations including low pressure drop packed-bed or packed-towers, plate or tray columns, spray chambers and high pressure drop venturi scrubbers.

A key concern for the use of wet scrubbing technology for the removal of SO_2 is the formation of H_2SO_4 which occurs when gas phase SO_3 vapor combines with water vapor in the scrubber body. A low pressure drop wet packed scrubber tower does not provide for adequate removal capability of the H_2SO_4 generated by the scrubber. H_2SO_4 generated by a wet scrubber is comprised of particles that are sub-micron in size; therefore, H_2SO_4 control technology must be able to remove small particles. EPC has identified the three following potential wet scrubber control technologies that can be used to remove SO_2 without increasing H_2SO_4 through the use of control technology that will ensure removal of small particles:

- A low pressure drop wet packed scrubber followed by a wet ESP;
- A low pressure drop wet packed scrubber followed by a demister; and
- A high pressure drop venturi scrubber.

The three technologies identified above all provide similar SO_2 and H_2SO_4 control; however, a high pressure drop venturi scrubber is the lowest cost option and the vendor contacted by EPC was able to guarantee a potential control efficiency for this option of up to 61%. Since the high pressure drop venturi scrubber is the lowest cost option, EPC has not further considered the low pressure drop wet packed scrubber followed by a wet ESP or a low pressure drop wet packed scrubber followed by a demister. EPC considers the use of a high pressure drop venturi scrubber to control SO_2 and H_2SO_4 emissions from the No. 8 Boiler to be technically feasible.

4.3.2.3 Dry Scrubbing

Dry scrubbing encompasses several different alternatives in which a dry reagent is injected in the gas stream downstream from the boiler and prior to the air pollution control equipment. A nearly instantaneous reaction takes place between the reagent and the acid gases, producing neutral salts that must be removed by particulate air pollution control equipment located downstream. The conceptual design of a dry scrubbing system is based on dry injection of a reagent (such as hydrated lime) into the flue gas via a circulating fluidized bed (CFB) vessel.

The CFB process represents an alternative to wet scrubbing, with the potential for achieving SO_2 capture rates with high levels of reliability and less maintenance than semi-dry or wet scrubbing systems. The flue gas would be directed to the CFB for scrubbing of gaseous pollutants and is then cleaned of particulate matter by downstream control equipment, such as an ESP or fabric filter, which collects the solid by-product and recirculates it back into the CFB.

The process is totally "dry", meaning it produces a dry disposal product and also introduces the lime reagent as a dry powder. The benefits of this type of system include the elimination of liquid handling equipment requiring routine maintenance such as pumps, agitators, atomizers, thickeners, and sludge dewatering equipment. The drawbacks to using this type of system are the costs associated with the installation of a new ESP and/or fabric filter to collect and recirculate the dry by-product back to the CFB.

EPC believes that the removal efficiency for a dry scrubber would be similar to a semi-dry scrubber, and a vendor for the semi-dry scrubber option was able to guarantee no more than 25% potential control efficiency due to the low inlet concentration. No applications of this technology on fuel oil and natural gas fired boilers such as the No. 8 Boiler were identified in our research of potential control technologies; therefore, EPC does not consider this to be technically feasible. In order to be conservative, EPC considers this technology to potentially be transferable to the No. 8 Boiler and evaluated it anyway.

4.3.2.4 Semi-dry Scrubbing

The conceptual design of a semi-dry scrubbing system is based on atomizing a reagent slurry stream containing lime and contacting the flue gases in a spray dryer vessel. The dry material consisting of un-reacted lime, reaction products, and fly ash must be collected downstream by an ESP or a fabric filter.

In conventional applications, the flue gas would be directed to a Semi-Dry Absorber (SDA) which is a vertical-downflow chamber designed to provide optimal gas and liquid spray interactions and retention time for evaporative cooling and lime slurry spray-dry absorption of acid gases. All of the sprayed liquid would evaporate as it travels in the tower, leaving only dry reagent products at the discharge. The partially reacted lime powder and ash would then be transported from the SDA vessel into the flue gas to ESP or fabric filter for final treatment. The reagent used would be calcium hydroxide, which is hydrated lime.

A vendor for this control option was able to guarantee no more than 25% potential control efficiency due to the low inlet concentration. No applications of this technology on fuel oil and natural gas fired boilers such as the No. 8 Boiler were identified in our research of potential control technologies; therefore, EPC does not consider this technology to be technically feasible. In order to be conservative, EPC considers this technology to potentially be transferable to the No. 8 Boiler and evaluated it anyway.

4.3.3 Evaluate Control Effectiveness of Remaining Technically Feasible Control Technologies (Step 3)

Based on the reasons outlined in the above discussion, EPC has identified the following control technologies as technically feasible, ranked in order of most effective to least effective:

- Lower Sulfur Fuels – 99% control switching to natural gas only;

- Lower Sulfur Fuels – 91% control switching to No. 2 fuel oil;
- High Pressure Drop Wet Scrubbing – 61% control;
- Dry Scrubbing – 25% control; and
- Semi-Dry Scrubbing – 25% control.

4.3.4 Evaluate Impacts and Document Results (Step 4)

The following evaluation considers the economic, energy, and environmental impacts of the technically feasible control technologies to the No. 8 Boiler for SO_2 control.

4.3.4.1 Economic Impacts of Control Technologies

As discussed in Section 4.2.4.1, the No. 8 Boiler is located in an area where there is not room for expansion, making installation of large add-on control technologies difficult. In order to accommodate some of the large equipment installations, EPC estimated installation costs to elevate equipment on catwalks. Since the No. 8 Boiler is ID fan limited, several of the add-on control technology installations would also require the purchase and installation of additional fan capacity. Additionally, the existing stack would not be adequate following the installation of several of the add-on control technology installations and EPC estimated the costs associated with replacement of the stack in these circumstances.

Table 4-2 provides a summary of the economic impact analysis for the technically feasible control technologies. EPC followed the guidance and procedures outlined in 40 CFR Part 51, Appendix Y and the *OAQPS Air Pollution Cost Control Manual.* Supporting cost evaluation spreadsheets are provided in Attachment C, Table Nos. C-5, C-6, C-7, C-8, and C-9.

4.3.4.2 Energy and Environmental Impacts of Control Technologies

If lower sulfur fuels were utilized at the No. 8 Boiler, there would not be any substantial energy impacts, other than the use of No. 2 fuel oil would require more gallons in order to provide the same heat input as the No. 6 fuel oil on an annual basis. It is possible that the utilization of natural gas instead of fuel oil could contribute to increased NO_X emissions on an annual basis unless low- NO_X burners were installed as well.

Table 4-2
Summary of Economic Impact Analysis – No. 8 Boiler SO_2 Controls

Control Technology	Baseline Emission Rate (TPY)	Emissions Performance Level	Expected Emissions Reductions (TPY)	Summary of Costs
Lower Sulfur Fuels (Switching to Burn Natural Gas Only)	114.9	99%	114.3	Total Annualized Cost: $482,500 Average Cost Effectiveness: $4,200/ton Average Cost Effectiveness: $2,412,500/dv
Lower Sulfur Fuels (Switching to Burn No. 2 Fuel Oil)	114.9	91%	104.4	Total Annualized Cost: $4,114,800 Average Cost Effectiveness: $39,400/ton Average Cost Effectiveness: $20,574,000/dv
High Pressure Drop Wet Scrubbing	114.9	61%	70.1	Total Annualized Cost: $2,162,400 Average Cost Effectiveness: $30,900/ton Average Cost Effectiveness: $21,624,000/dv
49 Dry Scrubbing	114.9	25%	28.7	Total Annualized Cost: $3,716,700 Average Cost Effectiveness: $129,400/ton Average Cost Effectiveness: $37,167,000/dv
Semi-Dry Scrubbing	114.9	25%	28.7	Total Annualized Cost: $3,413,200 Average Cost Effectiveness: $118,800/ton Average Cost Effectiveness: $34,132,000/dv

If high pressure drop wet scrubbing were installed on the No. 8 Boiler, there would be an impact on energy requirements due to increased electrical demand for the larger fan as well as the energy necessary to operate the scrubber itself. The increased energy requirements imposed on the boilers would result in the release of additional air pollutants. Other environmental considerations for wet scrubbing systems include negative impacts to the wastewater treatment plant because there would be an increase in dissolved solids in the wastewater and a subsequent increase in the toxicity of the waste water that will impact the bacteria in the activated sludge system. Depending upon the severity of the toxic impact, the ability to meet the requirements of the Mill's NPDES permit could be jeopardized. Any increases to the toxicity of the dissolved solids would also increase the toxicity of the treated wastewater discharged into the receiving stream at the outlet of the Mill's wastewater treatment system. Increased load of suspended solids at the treatment plant's clarifiers would require disposal in a landfill and increased utilization of the treatment plant aerators would require additional energy.

If dry or semi-dry scrubbing were installed on the No. 8 Boiler, there would be an impact on energy requirements due to increased electrical demand for the larger fan as well as the energy necessary to operate the scrubbers and downstream particulate control devices. The increased energy requirements imposed on the boilers would result in the release of additional air pollutants. Other environmental considerations for dry or semi-dry scrubbing systems include the stream of solid waste that would be generated and disposed of in a landfill.

4.3.5 Evaluate Visibility Impacts (Step 5)

40 CFR Part 51, Appendix Y provides limited guidance on how to evaluate the visibility impacts of the pre- and post-control modeling results. Appendix Y does provide the following two determinations:

- Evaluate a net visibility improvement determination; and
- Compare the 98^{th} percentile days for the pre and post control runs.

Evaluate a net visibility improvement determination

The BART Control Modeling analysis is provided in Section 2 of this document. The modeled changes in visibility in the Seney Wilderness due to the addition of add-on SO_2 control to the No.

8 Boiler can be summarized through the following relationships:

- Table 2-3 of this report shows that without add-on SO_2 control, there are 11 days over the 0.5 deciview "contribute to visibility impairment" threshold over the three year modeled period (1,093 days).
- The most stringent and cost effective SO_2 controls identified (fuel switch to natural gas only and switch to low sulfur fuel oil) reduces the number of days over the 0.5 deciview threshold to 2 days and 3 days respectively over the three year modeled period. For the high ΔP Scrubber the number of days over 0.5 deciview is 4 and for dry scrubber/semi-dry scrubber the number of days is 5.
- As shown in Table 2-6 of this report, the net maximum 24-hr visibility improvement realized for a fuel switch to natural gas only or No. 2 fuel oil is 0.4 deciview. The use of the high ΔP scrubber results in the net maximum visibility improvement of 0.2 deciview, while the dry scrubber/semi-dry scrubber system would result in a net maximum improvement of 0.1 deciview.

Compare the 98th percentile days for the pre and post control runs

In Table 2-6 of this report, the net visibility change to the 98th percentile daily impacts per modeled year for each of the technically feasible control technologies are shown. The highest change in 98th percentile visibility impact for each control technology is shown below:

- Natural Gas Only – 0.2 deciview
- No. 2 Fuel Oil Only – 0.2 deciview
- High ΔP Scrubber – 0.1 deciview
- Dry Scrubber/Semi-Dry Scrubber – 0.1 deciview

4.3.6 Identify BART

Based on the information developed in the Impacts Analysis, BART for SO_2 from the No. 8 Boiler is identified as the current operation of the boiler with no add-on controls.

4.4 PM_{10} BART ANALYSIS

PM_{10} emissions from the No. 8 Boiler are generated as part of the combustion process. PM_{10} emissions are primarily due to the combustion of fuel oil and are based on the ash content of the fuel and the completeness of the combustion process.

4.4.1 Identification of MACT Applicability and Identification of BART

The typical first step in the BART analysis is the identification of all available retrofit control options. However, 40 CFR Part 51, Appendix Y (IV, C) identifies an exception to the BART analysis for VOC and PM sources subject to Maximum Achievable Control Technology (MACT) standards under Section 112 of the Clean Air Act. Specifically, Appendix Y states that:

> *"We believe that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without identifying control options that would cost many thousands of dollars per ton. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, you may rely on the MACT standards for the purposes of BART."*

The No. 8 Boiler is subject to 40 CFR Part 63, Subpart DDDDD – "Boiler MACT", with an upcoming compliance date in 2007. The No. 8 Boiler does not have add-on controls for PM emissions and Boiler MACT does not require the control of PM emissions from an existing gas-fired or liquid fuel-fired boiler. Since the Boiler MACT is a current MACT standard, EPC believes that there are no existing or "new technologies subsequent to the MACT standard" that EPC should review. As such, EPC believes that the current configuration of No. 8 Boiler with no controls for PM represents BART for PM_{10} control and that no further analysis is required for PM_{10}.

<u>The following information also supports this conclusion:</u>

1. <u>PM_{10} emissions are low based on the firing of natural gas and fuel oil.</u>
2. <u>PM_{10} emissions from the No.8 Boiler has a minimal impact on the visibility analysis and a reduction in these emissions would have no impact on the contribution of the No. 8 Boiler to the overall visibility impacts.</u>

5. NO. 9 BOILER (EU9B03)

The following subsections describe the No. 9 Boiler and its BART analysis for each VIP. The BART analysis includes identification of all available retrofit control technologies, discussion of technical feasibility, control effectiveness, economic impacts, environmental impacts, visibility impacts, and a final BART determination.

5.1 NO. 9 BOILER DESCRIPTION

The No. 9 Boiler is a Babcock & Wilcox boiler rated for 250,000 pounds of steam per hour that provides steam for mill processes and steam turbine-generator sets for producing electricity. The No. 9 Boiler burns primarily bark generated on-site, but may also burn natural gas and paper cores. Bark is supplied to the boiler by a bark handling system. This system consists of a pneumatic system that moves the bark from the Woodyard Area to the boiler where it is combusted from a stoker grate moving on the bottom of the boiler.

The products of combustion (flue gases) pass up through the furnace, superheater section, generating section, and through the economizer section. The gases then flow down through the tubes of the air heater and enter the multi-tube dust collector that removes fly ash from the gas stream. The centrifugal force of the spiraling gas stream forces the ash to drop out of the stream and collect in the ash hoppers. The flue gases leave the dust collector and enter the inlet of the ID fan. The ID fan discharges into parallel wet scrubbers which remove particulate matter from the gas stream. The flue gases flow from the wet scrubbers and discharges to atmosphere.

The No. 9 Boiler is equipped with under grate and over grate (overfire) air. The optimization of the air distribution to under and overfire air ports helps to minimize carbon monoxide (CO), PM, and NO_X emissions. In this method, the air introduced through the undergrate air ports is reduced below the theoretical amount needed for complete combustion. The balance of the combustion air required for complete combustion is supplied through the overfire air ports at a point where most of the fuel has been oxidized and combustion temperatures are lower.

The No. 9 Boiler emits the following VIPs that require a BART analysis: SO_2, NO_X, and PM_{10}. The BART analysis for each pollutant is provided below.

5.2 NO_X BART ANALYSIS

The theory behind the mechanism for NO_X emission generation from the No. 9 Boiler is the same as the description previously identified in Section 4.2. The NO_X formed from the fuels combusted in the No. 9 Boiler is a combination of both Thermal NO_X and Fuel NO_X. A top down analysis to determine the best available NO_X control technology is provided in the following subsections.

5.2.1 Identification of All Available Retrofit Control Technologies (Step 1)

Based on the data review process described previously, a list of potential technologies for controlling NO_X emissions from No. 9 Boiler was formulated. EPC identified the following potential control technologies:

- SCR;
- LNB;
- SNCR; and
- Combustion Control Methods - Flue Gas Recirculation (FGR).

5.2.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down BART analysis is an evaluation of the technical feasibility of each of the identified control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility with respect to the No. 9 Boiler.

5.2.2.1 Selective Catalytic Reduction (SCR)

The mechanism by which SCR functions to control NO_X emissions was described previously in Section 4.2.2.1.

The most effective operation of an SCR system requires stable exhaust gas flow rates, NO_X concentrations, and exhaust gas temperature. Fly ash and other particulate matter in the exhaust gas stream can deactivate the catalyst through blinding, plugging, or fouling. The particulate matter deposits on the surface and in the active pore sites of the catalyst can also cause erosion of the catalyst surface. Such conditions typically result in frequent catalyst cleaning and replacement requirements or utilization of a more robust and expensive catalyst.

EPC has discussed the feasibility of using SCR control technology on a wood-fired boiler with two different vendors. While both believe that it is a difficult environment for the use of SCR control technology due to the particulate loading, both believe that it can be used successfully. One vendor provided a cost estimate to install an SCR system after the existing air heater and prior to the existing scrubbers in order to take maximum advantage of the exhaust gas temperature. Placing an SCR system in this location (on the hot, dirty side) at a temperature of 350°F would still require the installation of an air re-heater to elevate temperature up to 600°F; however, the temperature increase necessary if the installation was following the existing scrubbers would be much greater. The increase in flue gas temperature would be accomplished by using a gas burner (22.3 MMBtu/hr) to re-heat the gas stream and would add significant cost and would result in some increases to emissions.

<u>The EPA RBLC database does not contain any examples of SCR technology applied to wood fuel boilers, and EPC is not aware of its installation and demonstrated success on any wood fuel boilers in the pulp and paper industry. Therefore, EPC does not consider this technology to be technically feasible. In order to be conservative, EPC considers this technology to potentially be transferable to the No. 9 Boiler and evaluated it anyway.</u>

5.2.2.2 Low NO_X Burners

The mechanism by which LNB function to control NO_X emissions was described previously in Section 4.2.2.2.

The No. 9 Boiler is equipped with natural gas burners that are located above the stoker grate. It would be possible to retrofit the existing natural gas burners with LNB. However, it should be noted that the primary fuel for the No. 9 Boiler is bark burned from the stoker grate (not natural gas). As a result, the actual reductions of NO_X using LNB for the natural gas burners is not expected to be large, with approximately 40% removal efficiency for NO_X due to natural gas combustion.

EPC considers the potential application of LNB on the No. 9 Boiler for the natural gas burners to be technically feasible.

5.2.2.3 Selective Non-Catalytic Reduction (SNCR)

The mechanism by which SNCR functions to control NO_X emissions was described previously in Section 4.2.2.3.

The vendor contacted by EPC would not guarantee a NO_X removal efficiency of greater than 35%. However, the potential application of SNCR on the No. 9 Boiler is considered to be technically feasible.

5.2.2.4 Combustion Control Methods

Combustion control methods encompass a variety of design and operating features including low excess air, OFA, and FGR. The No. 9 Boiler is already equipped with an OFA system which serves to minimize NO_X emissions through staged combustion.

FGR entails recirculating a portion of relatively cool exhaust gases back into the combustion process in order to lower the flame temperature and reduce NO_X formation. Flue gas recirculation technology can be classified into two types; external or induced. External flue gas recirculation utilizes an external fan to recirculate the flue gases back into the flame. External piping routes the exhaust gases from the stack to the burner. A valve controls the recirculation rate, based on boiler input. Induced flue gas recirculation utilizes the combustion air fan to recirculate the flue gases back into the flame. A portion of the flue gases are routed by duct work or internally to the combustion air fan, where they are premixed with the combustion air and introduced into the flame through the burner.

EPC searched the RACT/BACT/LAER Clearinghouse and did not find the application of FGR to wood-fired boilers with under grate air and OFA systems. However, one vendor indicated that

FGR is in the development process for a similar boiler located at another company. The vendor indicated that the maximum NO_X removal efficiency would be minimal between 10% and 20%. Furthermore, the vendor identified that other pollutants may experience an increase as a result of utilizing FGR, including CO, toxic air contaminants, hazardous air pollutants, and other organics. The vendor also indicated the application of FGR in the No. 9 Boiler could also create a "sandblasting" effect on the existing boiler tubes due to the increased air flow rates that the boiler would experience.

As a result of this information, EPC does not consider this technology to be technically feasible for the No. 9 Boiler. In order to be conservative, EPC considered this technology to be potentially transferable and evaluated it anyway.

5.2.3 Evaluate Control Effectiveness of Remaining Technically Feasible Control Technologies (Step 3)

Based on the reasons outlined in the above discussion, EPC has identified the following control technologies as technically feasible, ranked in order of most effective to least effective:

- SCR – 90% control;
- LNB – 40% control for natural gas related NO_X emissions;
- SNCR – 35% control; and
- Combustion Control Methods (FGR) – 20% control.

5.2.4 Evaluate Impacts and Document Results (Step 4)

The following evaluation considers the economic, energy, and environmental impacts of applying SCR, LNB, SNCR, or FGR to the No. 9 Boiler for NO_X control.

5.2.4.1 Economic Impacts of Control Technologies

Similar to the No. 8 Boiler, the No. 9 Boiler is located in an area where there is not room for expansion, making installation of large add-on control technologies difficult. In order to accommodate some of the large equipment installations, EPC estimated installation costs to elevate equipment on catwalks. Several of the add-on control technology installations would also require the purchase and installation of additional fan capacity and the existing stacks would not be adequate following the installation of several of the add-on control technologies. EPC considered these parameters when evaluating the purchased equipment and installation costs for the BART analysis.

Table 5-1 provides a summary of the economic impact analysis for the technically feasible control technologies. EPC followed the guidance and procedures outlined in 40 CFR Part 51, Appendix Y and the *OAQPS Air Pollution Cost Control Manual.* Supporting cost evaluation spreadsheets are provided in Attachment C, Table Nos. C-10, C-11, C-12, and C-13.

5.2.4.2 Energy and Environmental Impacts of Control Technologies

If SCR were installed on the No. 9 Boiler, there would be substantial energy impacts in order to elevate the flue gases to the optimum temperature for the SCR control device. The SCR control device would be installed following the existing air heater and before the existing scrubbers in order to take advantage of the higher flue gas temperature at that location. Even using this location requires elevation of flue gas temperature and EPC calculated that 22.3 MMBtu/hr of natural gas would be necessary to elevate the flue gases from 350°F up to 600°F using this optimum location. Utilization of SCR could contribute to environmental impacts which were described in Section 4.2.4.2 and include the potential for increased greenhouse gas emissions and ammonia slip.

If LNB were installed on the No. 9 Boiler, there would be a reduction in energy efficiency related to the burner design and tuning in order to optimize the combustion characteristics and reduce the formation of NO_X. There are no environmental impacts associated with using LNB.

If SNCR were installed on the No. 9 Boiler, there would be reduction in energy efficiency as a result of the reduction reaction using thermal energy from the boiler, thus requiring additional fuel for the equivalent amount of current thermal output. In addition to the energy impacts, there are environmental impacts due to the potential for increased greenhouse gas emissions and ammonia slip.

Table 5-1
Summary of Economic Impact Analysis – No. 9 Boiler NO_x Controls

Control Technology	Baseline Emission Rate (TPY)	Emissions Performance Level	Expected Emissions Reductions (TPY)	Summary of Costs
SCR	296.6	90%	266.9	Total Annualized Cost: $3,673,000 Average Cost Effectiveness: $13,800/ton Average Cost Effectiveness: $36,730,000/dv
LNB	33.9	40% for natural gas combustion only	13.6	Total Annualized Cost: $256,200 Average Cost Effectiveness: $18,900/ton Average Cost Effectiveness: >$5,124,000/dv
SNCR	296.6	35%	103.8	Total Annualized Cost: $1,115,000 Average Cost Effectiveness: $10,700/ton Average Cost Effectiveness: >$22,300,000/dv
FGR	296.6	20%	59.3	Total Annualized Cost: $1,137,300 Average Cost Effectiveness: $19,200/ton Average Cost Effectiveness: >$22,746,000/dv

If FGR were installed on the No. 9 Boiler, there would not be a substantial energy impact. However, the utilization of FGR could potentially increase products of incomplete combustion which could result in increased emissions of CO, toxic air contaminants, hazardous air pollutants, and other organics.

5.2.5 Evaluate Visibility Impacts (Step 5)

40 CFR Part 51, Appendix Y provides limited guidance on how to evaluate the visibility impacts of the pre and post control modeling results. Appendix Y does provide the following two determinations:

- Evaluate a net visibility improvement determination; and
- Compare the 98th percentile days for the pre and post control runs.

Evaluate a net visibility improvement determination

EPC provided multiple BART Control Modeling analyses in Section 2 of this document. Section 2 addresses the overall visibility improvement using a pre and post control analysis. The modeled changes in visibility in the Seney Wilderness due to the addition of add-on NO_X control to the No. 9 Bark Boiler can be summarized through the following relationships:

- As shown in Table 2-3 of this report, there are no days over the three year modeled period (1,093 days) where the concentrations due to emissions from the No. 9 Boiler result in an impact of 0.5 deciview. Thus the No. 9 Boiler does not by itself contribute to visibility impairment.
- The data in Table 2-5 of this report show that the addition of any of the four NO_X controls has virtually no impact on visibility improvement.
- As shown in Table 2-6 of this report, the differences in 24-hr visibility impacts for SCR, low NO_X burners, SNCR, and FGR range from 0.1 deciview to less than 0.1 deciview.

Compare the 98th percentile days for the pre and post control runs

Table 2-6 of this report shows the net visibility change to the 98th percentile daily impacts per modeled year for each of the technically feasible control technologies. The highest change in

98th percentile visibility impact for each control technology is shown below:

- SCR – 0.1 deciview
- Low NO_X Burners – less than 0.1 deciview
- SNCR – less than 0.1 deciview
- FGR – less than 0.1 deciview

5.2.6 Identify BART

Based on the information developed in the Impacts Analysis, BART for NO_X from the No. 9 Boiler is identified as no additional controls.

5.3 SO_2 BART ANALYSIS

Sulfur dioxide (SO_2) emissions from the No. 9 Boiler are the result of the combustion of bark and natural gas, both of which contain very low levels of sulfur for oxidation to SO_2. As a result the SO_2 emissions from this source are relatively low without any additional control due to the low sulfur content of the fuels burned and the alkalinity of the wood ash that acts as an "in-situ" scrubber.

5.3.1 Identification of All Available Retrofit Control Technologies (Step 1)

Based on the data review process described previously, a list of potential technologies for controlling SO_2 emissions from No. 9 Boiler was formulated. EPC identified the following potential control technologies:

- Low Sulfur Fuels;
- Wet Scrubbing (addition of caustic to existing scrubbers);
- Dry Scrubbing; and
- Semi-dry Scrubbing.

5.3.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down BART analysis is an evaluation of the technical feasibility of each of the identified control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility with respect to the No. 9 Boiler.

5.3.2.1 Low Sulfur Fuels

The mechanism by which lower sulfur fuels function to control SO_2 emissions was described previously in Section 4.3.2.1. The No. 9 Boiler is already burning low sulfur fuels (bark and natural gas). There are not any fuel substitutions that could occur to reduce the existing fuel sulfur contents any lower. As a result, this is not a technically feasible control option for the No. 9 Boiler.

5.3.2.2 Wet Scrubbing (Addition of Caustic to Existing Scrubbers)

The mechanism by which wet scrubbing functions to control SO_2 emissions was described previously in Section 4.3.2.2.

As discussed previously, the No. 9 Boiler is equipped with parallel wet scrubbers that provide particulate matter control. The addition of caustic to the existing wet scrubbers could potentially provide some additional control of SO_2 emissions. Therefore EPC considers the addition of caustic to the existing wet scrubbers to be technically feasible.

5.3.2.3 _Dry Scrubbing

The mechanism by which dry scrubbing functions to control SO_2 emissions was described previously in Section 4.3.2.3.

The drawbacks to using a dry scrubbing system on the No. 9 Boiler are the costs associated with expensive retrofits to the existing air pollution control system (including the removal of the existing wet scrubbers and the installation of a new ESP and/or fabric filter to collect and recirculate the dry by-product back to the CFB.) No applications of this technology on biomass-fired stoker grate boilers such as the No. 9 Boiler were identified in our research of potential control technologies. EPC contacted a vendor for further information regarding semi-dry scrubbing technology and the vendor was not able to guarantee any removal efficiency of SO_2 due to the low inlet concentration. The use of dry scrubbing technology is similar to semi-dry scrubbing technology and would not be expected to effectively provide emissions reductions due to the low inlet concentration. As a result, this is not a technically feasible control option for the No. 9 Boiler.

5.3.2.4 Semi-dry Scrubbing

The mechanism by which semi-dry scrubbing functions to control SO_2 emissions was described previously in Section 4.3.2.4.

The drawbacks to using a semi-dry scrubbing system on the No. 9 Boiler are the costs associated with expensive retrofits to the existing air pollution control system (including the removal of the existing wet scrubbers and the installation of a new ESP and/or fabric filter). No applications of this technology on biomass-fired stoker grate boilers such as the No. 9 Boiler were identified in our research of potential control technologies. EPC contacted a vendor for further information and the vendor was not able to guarantee any removal efficiency of SO_2 due to the low inlet concentration. As a result, this is not a technically feasible control option for the No. 9 Boiler.

5.3.3 Evaluate Control Effectiveness of Remaining Technically Feasible Control Technologies (Step 3)

Based on the reasons outlined in the above discussion, EPC has identified the following control technologies as technically feasible:

- Wet Scrubbing (Addition of Caustic to Existing Scrubbers) – 50% control.

5.3.4 Evaluate Impacts and Document Results (Step 4)

The following evaluation considers the economic, energy, and environmental impacts of the technically feasible control technology to the No. 9 for SO_2 control.

5.3.4.1 Economic Impacts of Control Technologies

A summary of the economic impact analysis for the technically feasible control technology is provided in Table 5-2. EPC followed the guidance and procedures outlined in 40 CFR Part 51, Appendix Y and the *OAQPS Air Pollution Cost Control Manual.* Supporting cost evaluation spreadsheets are provided in Attachment C, Table No. C-14.

Table 5-2
Summary of Economic Impact Analysis – No. 9 Boiler SO_2 Controls

Control Technology	Baseline Emission Rate (TPY)	Emissions Performance Level	Expected Emissions Reductions (TPY)	Summary of Costs
Wet Scrubbing (Addition of Caustic to Existing Scrubbers)	43.1	50%	21.6	Total Annualized Cost: \$470,000 Average Cost Effectiveness: \$21,800/ton Average Cost Effectiveness: > \$4,700,000/dv

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5.3.4.2 Energy and Environmental Impacts of Control Technologies

If caustic was added to the existing wet scrubbers currently installed on the No. 9 Boiler, there would be a negligible impact on energy requirements. However, other environmental considerations for a caustic scrubbing system include negative impacts to the wastewater treatment plant because there would be an increase in dissolved solids in the wastewater and a subsequent increase in the toxicity of the waste water that will impact the bacteria in the activated sludge system. Depending upon the severity of the toxic impact, the ability to meet the requirements of the Mill's NPDES permit could be jeopardized. Any increases to the toxicity of the dissolved solids would also increase the toxicity of the treated wastewater discharged into the receiving stream at the outlet of the Mill's wastewater treatment system. Increased load of suspended solids at the treatment plant's clarifiers would require disposal in a landfill and increased utilization of the treatment plant aerators would require additional energy.

5.3.5 Evaluate Visibility Impacts (Step 5)

40 CFR Part 51, Appendix Y provides limited guidance on how to evaluate the visibility impacts of the pre and post control modeling results. Appendix Y does provide the following two determinations:

- Evaluate a net visibility improvement determination; and
- Compare the 98^{th} percentile days for the pre and post control runs.

Evaluate a net visibility improvement determination

EPC provided multiple BART Control Modeling analyses in Section 2 of this document. In Section 2 of this report, the overall visibility improvement using a pre and post control analysis are addressed. The modeled changes in visibility in the Seney Wilderness due to the addition of add-on SO_2 control to the No. 9 Boiler can be summarized through the following relationships:

- As shown in Table 2-3 of this report, no days over the three year modeled period (1,093 days) have a 24-hr visibility impact from the No. 9 Boiler that is greater than the "contribute to visibility impairment" threshold of 0.5 deciview.
- In Table 2-5 of this report, the addition of caustic to the existing scrubber controlling

the No. 9 Boiler shows that there is no significantly improvement to the already low visibility impacts.

- As shown in Table 2-6 of this report, the maximum difference in 24-hr visibility impacts between the base case and control scenarios is nearly zero.

Compare the 98th percentile days for the pre and post control runs

In Table 2-6 of this report, the net visibility change to the 98^{th} percentile daily impacts per modeled year for the scrubber scenario (the only control option considered) is shown. The highest change in 98^{th} percentile visibility impact for the addition of caustic to the current scrubber is less than 0.1 deciview.

5.3.6 Identify BART

Based on the information developed in the Impacts Analysis, BART for SO_2 from the No. 9 Boiler is identified as no additional controls.

5.4 PM_{10} BART ANALYSIS

PM_{10} emissions from the No. 9 Boiler are generated as part of the combustion process. PM_{10} emissions from bark combustion are based on the completeness of the combustion process.

5.4.1 Identification of MACT Applicability and Identification of BART

The typical first step in the BART analysis is the identification of all available retrofit control options. However, 40 CFR Part 51, Appendix Y (IV, C) identifies an exception to the BART analysis for VOC and PM sources subject to Maximum Achievable Control Technology (MACT) standards under Section 112 of the Clean Air Act. Specifically, Appendix Y states that:

> *"We believe that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without identifying control options that would cost many thousands of dollars per ton. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, you may rely on the MACT standards for the purposes of BART."*

The No. 9 Boiler is subject to 40 CFR Part 63, Subpart DDDDD – "Boiler MACT", with an upcoming compliance date in 2007. EPC believes that the current control configuration is sufficient to comply with the Boiler MACT. In addition, since the Boiler MACT is a current MACT standard, EPC believes that there are no other "new technologies subsequent to the MACT standard" that EPC should review.

As such, EPC believes that the multiclone dust collectors in series with the two parallel wet scrubbers represent BART for PM_{10} control and that no further analysis is required for PM_{10}.

6. NO. 10 RECOVERY FURNACE (EURF15)

The following subsections describe the No. 10 Recovery Furnace and its BART analysis for each VIP. The BART analysis includes identification of all available retrofit control technologies, discussion of technical feasibility, control effectiveness, economic impacts, environmental impacts, visibility impacts, and a final BART determination.

6.1 NO. 10 RECOVERY FURNACE DESCRIPTION

The No. 10 Recovery Furnace is a Babcock and Wilcox unit used to regenerate chemicals used in wood pulping. The No. 10 Recovery Furnace generates steam in the process of burning black liquor and is rated for 565,000 pounds of steam per hour. Steam from the No. 10 Recovery Furnace is used for mill processes and steam turbine-generator sets for producing electricity. The unit burns primarily black liquor, but also burns small quantities of natural gas and No. 6 fuel oil during startup and shutdown conditions. The unit is also capable of burning used oil when it is available, during startup and shutdown conditions. Inorganic material (smelt) from the bottom of the recovery furnace is used to produce green liquor, which is a solution of sodium sulfide and sodium carbonate salts, when it is dissolved in water or weak wash in the Smelt Dissolving Tank. Also, the No. 10 Recovery Furnace is used to incinerate High Volume Low Concentration non-condensable gases from the Digester System, Brownstock Washing System, and Evaporator System.

Combustion air is supplied at four levels in the furnace, using forced draft fans. The combustion gases are pulled upwards through the furnace by an induced draft fan. Heat is removed from the combustion gases in superheaters, steam generating sections and economizers. The combustion gases then pass to an ESP where PM is removed. From the ESP the combustion gases flow to the stack.

The No. 10 Recovery Furnace emits the following VIPs that require a BART analysis: SO_2, NO_X, and PM_{10}. The BART analysis for each pollutant is provided below.

6.2 NO_X BART ANALYSIS

The theory behind the mechanism for NO_X emission generation from the No. 10 Recovery Furnace is the same as the description previously identified in Section 4.2. The NO_X formed from the fuels combusted in the No. 10 Recovery Furnace is a combination of both Thermal NO_X and Fuel NO_X.

Kraft recovery furnaces are a unique type of combustion source that are inherently "low-NO_X". The furnace process involves injecting atomized black liquor through specially designed nozzles so that organics, including lignin derivatives, carbohydrates, soaps, waxes, and residual fiber will combust and the inorganic sodium compounds in the liquor can be recovered as molten smelt and tapped from the char bed at the furnace bottom. Most of the NO_X emissions from recovery furnaces can be attributed to Fuel NO_X resulting from partial oxidation of the black liquor nitrogen content. The No. 10 Recovery Furnace operates with a reducing zone in the lower part of the furnace and an oxidizing zone in the region of the liquor spray guns using secondary, tertiary, and quaternary staged combustion air.

A top down analysis to determine the best available NO_X control technology is provided in the following subsections.

6.2.1 Identification of All Available Retrofit Control Technologies (Step 1)

Based on the data review process described previously, a list of potential technologies for controlling NO_X emissions from No. 10 Recovery Furnace was formulated. EPC identified the following potential control technologies:

- SCR;
- LNB;
- SNCR; and
- Combustion Control Methods.

6.2.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down analysis is an evaluation of the technical feasibility of each of the identified control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility with respect to the No. 10 Recovery Furnace.

6.2.2.1 Selective Catalytic Reduction (SCR)

The mechanism by which SCR functions to control NO_X emissions was described previously in Section 4.2.2.1.

Extensive SCR experience has been gained on base-loaded combustion turbines firing natural gas and recently on base-loaded coal-fired utility boilers. There have not been any applications of SCR control technology on recovery furnaces in the United States and it is not understood how the unique characteristics of a recovery furnace exhaust gas stream would react with the catalyst. <u>Since this control technology has not been applied or demonstrated successfully on any recovery furnaces, EPC does not believe that SCR is a technically feasible control technology for the No. 10 Recovery Furnace.</u>

6.2.2.2 Low NO_x Burners (LNB)

The mechanism by which LNB functions to control NO_X emissions was described previously in Section 4.2.2.2.

The nozzles from which black liquor is injected into the No. 10 Recovery Furnace are uniquely designed in order to safely inject, pyrolize, and convert the black liquor. The tar-like black liquor material is atomized and sprayed into the furnace body making it impossible to utilize a LNB technology in this application.

Supplemental No. 6 fuel oil and natural gas are burned on startup and shutdown and do not contribute to significant quantities of NO_X emissions. EPC has determined that there is not enough space in the lower furnace area to accommodate retrofitted supplemental fuel burners and the additional natural gas burners that would need to be installed to accomplish this.

As a result, EPC does not believe that LNB is a technically feasible control technology for the No. 10 Recovery Furnace.

6.2.2.3 Selective Non-Catalytic Reduction (SNCR)

The mechanism by which SNCR functions to control NO_X emissions was described previously in Section 4.2.2.3.

Two vendors were contacted regarding their experience in the application of SNCR technology to Kraft recovery furnaces both domestically and internationally. One vendor had no knowledge of SNCR being applied to any Kraft recovery furnaces. The other vendor was involved in a single SNCR pilot demonstration project on a Kraft recovery furnace in Sweden in 1990. The short pilot study project resulted in a 60% reduction in NO_X emissions with about 8 ppm ammonia slip. SNCR was not used beyond the demonstration period and the long-term effect of SNCR on the recovery process and the recovery furnace could not be evaluated. A search of the RBLC confirmed that no domestic recovery furnace has used SNCR.

SNCR has not been applied to Kraft recovery furnaces in the United States for a variety of reasons. Safety concerns associated with SNCR systems include the risk of a smelt/water explosion should boiler tube walls corrode and leak near urea injection points and risks associated with an ammonia handling system for the SNCR system. Operational concerns associated with SNCR systems include the potential formation of acidic sulfates that would result in corrosion and possibility of catastrophic boiler tube failure.

As a result, EPC does not believe that SNCR is technically feasible as a control technology for the No. 10 Recovery Furnace.

6.2.2.4 Combustion Controls

Combustion control methods encompass a variety of design and operating features including low excess air, staged combustion, and FGR. The No. 10 Recovery Furnace is already operated using low excess air and staged combustion which serves to minimize NO_X emissions.

FGR is typically used in gas or oil-fired boilers where the flue gases are relatively clean and can be readily recirculated. The recovery furnace flue gases can not be readily recirculated due to the chemical composition of the particulate matter found in the flue gases. As such, FGR is considered a technically infeasible NO_X control technology for the No. 10 Recovery Furnace.

6.2.3 Evaluate Control Effectiveness of Remaining Technically Feasible Control Technologies (Step 3) and Identification of BART

Based on the reasons outlined in the above discussion, EPC has identified the use of combustion control methods as technically feasible. The Mill already implements effective combustion control methods through the use of low excess air and four levels of staged combustion air.

EPC believes that the existing combustion control methods represent the "top" technically feasible NO_X control technology for the No. 10 Recovery Furnace. 40 CFR Part 51, Appendix Y (IV, D., Step 1, 9) specifically states that:

> *"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. Likewise, if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses in this section."*

Based on the regulatory language provided in 40 CFR Part 51, Appendix Y, EPC believes that the existing combustion control methods represent BART, and that the remaining steps in the BART analysis are not required to be completed, by meeting the following criteria:

1. There are no other technically feasible control technologies available for Recovery Furnaces other than combustion controls for the abatement of NO_X; and
2. The federally-enforceable Title V Operating Permit includes permit conditions that identify an emission limit for NO_X.

6.3 SO_2 BART ANALYSIS

Sulfur dioxide (SO_2) emissions from the No. 10 Recovery Furnace are variable and are dependant on several factors including liquor properties (e.g., sulfidity, sulfur to sodium ratio, heat value, and solids content), combustion air, liquor firing patterns, furnace design features, and type of startup fuel. It is important to note that the No. 10 Recovery Furnace has the ability to utilize natural gas and No. 6 fuel oil for startup and shutdown procedures. Black liquor solids (BLS) firing produces sodium fume, which effectively scrubs SO_2 emissions. Fuel oil firing is not the typical furnace operating scenario and results in SO_2 emissions that are consistent with the sulfur content of the fuel.

6.3.1 Identification of All Available Retrofit Control Technologies (Step 1)

Based on the data review process described previously, a list of potential technologies for controlling SO_2 emissions from No. 10 Recovery Furnace was formulated. EPC identified the following potential control technologies:

- Wet Scrubbing;
- Dry Scrubbing; and
- Semi-Dry Scrubbing.

6.3.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down BART analysis is an evaluation of the technical feasibility of each of the identified control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility with respect to the No. 10 Recovery Furnace.

6.3.2.1 Wet Scrubbing

The mechanism by which wet scrubbing functions to control SO_2 emissions was described previously in Section 4.3.2.2.

Approximately 85% of the annual SO_2 emissions from the Recovery Furnace are associated with burning fuel oil during limited periods of time on startup and shutdown. The operation of the No. 10 Recovery Furnace during startup and shutdown is unstable and it is unlikely that a scrubber would be brought on-line prior to the Recovery Furnace being stabilized firing black liquor. In addition, wet caustic scrubbers have not been used to control SO_2 emissions from recovery furnaces such as the No. 10 Recovery Furnace. As a result, EPC considers the use of a wet scrubber to be a technically infeasible SO_2 control option for the No. 10 Recovery Furnace.

6.3.2.2 Dry Scrubbing

The mechanism by which dry scrubbing functions to control SO_2 emissions was described previously in Section 4.3.2.3.

The PM collected in a recovery furnace ESP is primarily salt cake (sodium carbonate). The collected salt cake is returned to the chemical recovery system for use in the process and, with the use of a dry scrubbing system, the collected particulate matter would not be useable in the chemical recovery process. In addition, the application of dry scrubbing technology to Kraft recovery furnaces such as the No. 10 Recovery Furnace was not identified in our research of potential control technologies. Therefore, EPC considers dry scrubbing technology to be a technically infeasible SO_2 control option for the No. 10 Recovery Furnace.

6.3.2.3 Semi-dry Scrubbing

The mechanism by which semi-dry scrubbing functions to control SO_2 emissions was described previously in Section 4.3.2.4.

Similar to the description identified above for dry scrubbing systems, the use of a semi-dry scrubbing system would preclude the use of the collected salt cake in the chemical recovery process. No applications of this technology on Kraft recovery furnaces such as the No. 10 Recovery Furnace were identified in our research of potential control technologies. Therefore, EPC considers this technology to be a technically infeasible SO_2 control option for the No. 10 Recovery Furnace.

6.3.3 Evaluate Control Effectiveness of Remaining Technically Feasible Control Technologies (Step 3)

Based on the reasons outlined in the above discussion, EPC has identified that none of the potential control technologies are technically feasible. Therefore, BART for SO_2 for the No. 10 Recovery Furnace is no additional controls.

6.4 PM_{10} BART ANALYSIS

PM_{10} emissions from the No. 10 Recovery Furnace are generated as part of the processing of black liquor solids and combustion of organics and sulfur compounds. Particulate emissions from the No. 10 Recovery Furnace are controlled by an existing ESP.

The typical first step in the BART analysis is the identification of all available retrofit control options. However, 40 CFR Part 51, Appendix Y (IV, C) identifies an exception to the BART analysis for VOC and PM sources subject to Maximum Achievable Control Technology (MACT) standards under Section 112 of the Clean Air Act. Specifically, Appendix Y states that:

> *"We believe that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without identifying control options that would cost many thousands of dollars per ton. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, you may rely on the MACT standards for the purposes of BART."*

The No. 10 Recovery Furnace is subject to 40 CFR Part 63, Subpart MM – "MACT II" with a compliance date of March 13, 2004. The No. 10 Recovery Furnace is in compliance with the PM standard of 0.044 gr/dscf at 8% O_2 (§63.862(a)(i)(A)). EPC has reviewed the RBLC database and believes that the current control configuration is still the most current technology and that there are no other "new technologies subsequent to the MACT standard" that EPC should review.

As such, EPC believes that the ESP control technology, in conjunction with the unit specific PM emission limit of 0.033 gr/dscf at 8% O_2 represents BART for PM_{10} control and that no further analysis is required for PM_{10}.

7. SMELT DISSOLVING TANK (EUST15)

The following subsections describe the Smelt Dissolving Tank and its BART analysis for each VIP. The BART analysis includes identification of all available retrofit control technologies, discussion of technical feasibility, control effectiveness, economic impacts, environmental impacts, visibility impacts, and a final BART determination.

7.1 SMELT DISSOLVING TANK DESCRIPTION

Inorganic materials from the combustion process accumulate on the No. 10 Recovery Furnace floor and drain into the Smelt Dissolving Tank as molten smelt. In the Smelt Dissolving Tank, the smelt is mixed with weak wash to form green liquor. The green liquor is then pumped to the causticizing area. The Smelt Dissolving Tank is controlled through a scrubber system for PM and total reduced sulfur emissions control. The scrubber operates with an alkaline scrubbing solution that also provides acid gas control.

The Smelt Dissolving Tank emits the following VIPs that require a BART analysis: SO_2 and PM_{10}. The BART analysis for each pollutant is provided below.

7.2 SO_2 BART ANALYSIS

Sulfur dioxide (SO_2) emissions from the Smelt Dissolving are dependent on how much sulfur carries over from the No. 10 Recovery Furnace with the smelt. Controlled smelt-water explosions in the Smelt Dissolving Tank can create SO_2 as a result of the oxidation of the sulfur in the smelt.

The typical first step in the BART analysis is the identification of all available retrofit control options; however, SO_2 emissions from the Smelt Dissolving Tank are very low at approximately 5 tpy. While 40 CFR Part 51 Appendix Y does not provide a deminimis emission rate threshold, EPC believes that SO_2 emissions of approximately 5 tpy do not justify a full BART analysis.

<u>EPC considers no control to be BART for SO_2 based on the following supporting information:</u>

1. <u>SO_2 emissions are extremely low based on the current operational and control configuration;</u>

2. EPC operates the Smelt Dissolving Tank and associated scrubber in a manner that complies with the MACT II PM emission limit and also ensures that SO_2 emissions are minimized;
3. SO_2 emissions from the Smelt Dissolving Tank have a minimal impact on visibility analysis; and
4. The Smelt Dissolving Tank emissions have a minimal impact on the overall visibility analysis.

7.3 PM_{10} BART ANALYSIS

PM_{10} emissions from the Smelt Dissolving Tank are generated as part of the processing of the smelt and the smelt-water reaction. PM_{10} emissions are comprised mainly of sodium compounds and are controlled by an existing scrubber.

The typical first step in the BART analysis is the identification of all available retrofit control options. However, 40 CFR Part 51, Appendix Y (IV, C) identifies an exception to the BART analysis for VOC and PM sources subject to Maximum Achievable Control Technology (MACT) standards under Section 112 of the Clean Air Act. Specifically, Appendix Y states that:

> *"We believe that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without identifying control options that would cost many thousands of dollars per ton. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, you may rely on the MACT standards for the purposes of BART."*

The Smelt Dissolving Tank is subject to 40 CFR Part 63, Subpart MM – "MACT II" with a compliance date of March 13, 2004. The Smelt Dissolving Tank is in compliance with the PM standard of 0.2 pounds/ton BLS (§63.862(a)(i)(B)). EPC has reviewed the RBLC database and believes that the current control configuration is still the most current technology and that there are no other "new technologies subsequent to the MACT standard" that EPC should review.

As such, EPC believes that the wet scrubber control technology, in conjunction with the PM emission limit of 0.2 lbs/ton BLS represents BART for PM_{10} control and that no further analysis is required for PM_{10}.

8. LIME KILN (EULK29)

The following subsections describe the Lime Kiln and its BART analysis for each VIP. The BART analysis includes identification of all available retrofit control technologies, discussion of technical feasibility, control effectiveness, economic impacts, environmental impacts, visibility impacts, and a final BART determination.

8.1 LIME KILN DESCRIPTION

The Lime Kiln processes lime mud from the causticizing area to regenerate calcium oxide. Lime mud from the mud storage tank is fed to the lime mud precoat vacuum filter where it is washed prior to being fed into the Lime Kiln. Inside the Lime Kiln, the lime mud is dried and heated to a high temperature where it converts the lime mud (calcium carbonate) to lime (calcium oxide). The "burnt" lime is conveyed to a storage silo above the slaker. Fresh makeup lime is unloaded by compressed air from trucks into a silo.

The Lime Kiln is heated with natural gas or fuel oil. The Lime Kiln serves as the back up incineration device for the Low Volume High Concentration (LVHC) non-condensable gases (NCG) from the Mill's pulping operation. The Lime Kiln is equipped with a high pressure drop venturi scrubber for control of PM. Caustic and/or weak wash is added to the scrubber sump to control SO_2 and total reduced sulfur emissions.

The Lime Kiln emits the following VIPs that require a BART analysis: SO_2, NO_X, and PM_{10}. The BART analysis for each pollutant is provided below.

8.2 NO_X BART ANALYSIS

The theory behind the mechanism for NO_x emission generation from the Lime Kiln is the same as the description previously identified in Section 4.2. The NO_x formed from the fuels combusted in the Lime Kiln is a combination of both Thermal NO_x and Fuel NO_x.

The Lime Kiln currently has the capability to burn natural gas and fuel oil and each fuel contributes to NO_X formation differently. Natural gas contributes to NO_X formation primarily through the Thermal NO_X mechanism because of the minimal nitrogen content of the fuel. On the other hand, most of the NO_X from oil firing is formed through the Fuel NO_X mechanism due to the nitrogen content of fuel oil. EPC researched NCASI published documents to support this information and observed supporting technical information in NCASI Technical Bulletin No. 885. The Technical Bulletin also identifies that Thermal NO_X formation is predominantly effected by kiln dry end temperature and kiln oxygen level, whereas Fuel NO_X formation is effected by kiln oxygen level, fuel type, and fuel nitrogen content.

8.2.1 Identification of All Available Retrofit Control Technologies (Step 1)

Based on the data review process described previously, a list of potential technologies for controlling NO_X emissions from the Lime Kiln was formulated. EPC identified the following potential control technologies:

- SCR;
- LNB Technology; and
- SNCR.

8.2.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down BART analysis is an evaluation of the technical feasibility of each of the identified control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility with respect to the Lime Kiln.

8.2.2.1 Selective Catalytic Reduction (SCR)

The mechanism by which SCR functions to control NOx emissions was described previously in Section 4.2.2.1.

Utilization of a catalyst in the SCR process allows for the reactions to occur within a lower and broader temperature range and using less retention time than the use of SNCR. This is an important issue regarding technical feasibility due to the exhaust gas temperature of approximately 160°F for the Lime Kiln. In an SCR system, the optimum temperature depends on both the type of catalyst utilized in the process and the flue gas composition. Typically, the minimum temperature required is 600°F to 750°F. In order for the Lime Kiln to be able to meet the minimum temperature requirement for the SCR process to be effective, the system would need to be equipped with a natural gas fired re-heater in order to raise the exhaust gas temperature, which adds to the complexity and costs associated with the overall system.

It is important to note than if the minimum temperature range is not satisfied, the reaction kinetics decrease and ammonia passes through the exhaust gas (referred to as "ammonia slip"). As a result, periods of startup, shutdown, or malfunction of the Lime Kiln and/or the re-heat system would create toxic emission concerns.

SCR catalysts are composed of active metals on ceramics with a highly porous structure containing activated sites where the reduction reaction occurs. After the reduction reaction occurs, the site reactivates via rehydration or oxidation; however, over time the catalyst activity decreases requiring replacement. Catalyst designs and formulations are generally proprietary and most catalyst vendors are concerned about the potential for catalyst fouling due to the presence in the lime kiln exhaust gas of sulfurous compounds and certain heavy metals which have the potential to foul the activated sites and/or poison the catalyst minimizing the catalyst life and effectiveness of the SCR system.

The amount of NO_X removal using a SCR system could vary from 70% to 90%. However, the drawbacks to using a SCR system are well documented and it is possible that since SCR has not been installed and operated on any lime kilns, it may not work at all. One vendor was located who believed it would be technically possible to utilize SCR on a lime kiln, although they have never applied it to a lime kiln. <u>Based on the discussion of technical feasibility in 40 CFR 51, Appendix Y, EPC considers this technology to be a technically infeasible NO_X control option for BART due to the discussion above and the fact that it has not been installed on a lime kiln.</u>

8.2.2.2 Low NO_X Burners

With respect to lime kilns, Low NO_X Burner technology refers to a combination of passive combustion control measures used to minimize NO_X formation from primarily Thermal NO_X and Fuel NO_X to a lesser extent. These combustion control measures include careful design of the fuel feed system in order to ensure proper fuel mixing with the air, and burner "tuning" or optimization which impacts fuel burning efficiency and overall flame length.

Based on discussions with Lime Kiln burner vendors, EPC understands that the term Low NO_X Burners is actually a misnomer when speaking in the context of lime kilns and in reality represents the detuning of the burner to reduce NO_X emissions while concurrently reducing the energy efficiency of the burner.

As a result of this information, EPC considers the use of Low NO_X Burner technology as it has been described herein to be a technically feasible passive combustion control option. EPC has already incorporated this burner "tuning" to optimize the relationship of NO_X emissions reductions and energy efficiency.

8.2.2.3 Selective Non-Catalytic Reduction (SNCR)

The mechanism by which SNCR functions to control NO_X emissions was described previously in Section 4.2.2.3.

The elevated temperatures necessary to support the NO_X reduction reaction without the presence of a catalyst creates a technical problem regarding potential utilization on a lime kiln. The Lime Kiln exhaust gas temperature is approximately 160°F and SNCR requires a minimum temperature of 1600°F. It would not be practical to install and operate a re-heat system to bring the exhaust gas temperature up to 1600°F in order to utilize SNCR for NO_X reduction. Similar to SCR, it is important to note than if the minimum temperature range is not satisfied, the SNCR reaction kinetics decrease and ammonia passes through the exhaust gas (referred to as "ammonia slip").

In order for the NO_X reduction reaction to be effective, SNCR requires a minimum residence time that the airflow exhaust rates could not support. As a result, in order for SNCR to be able to reduce NO_X, the reagent would have to be injected directly into the lime kiln body, which is not something that could be done given the rotating nature of the kiln.

The amount of NO_X removal using a SNCR system could vary from 30% to 50%. However, in addition to other technical concerns about ammonia slip, the system would need to achieve a minimum exhaust gas temperature of 1600°F, which is not a practical consideration regarding installation on a lime kiln. Furthermore, EPC was not able to locate any SNCR vendors who believed it would be technically possible to utilize SNCR on a lime kiln. Since the SNCR process has not been demonstrated commercially on any lime kilns, and due to the additional safety and operational concerns associated with SNCR applied to lime kilns, EPC considers SNCR technically infeasible.

8.2.3 Evaluate Control Effectiveness of Remaining Technically Feasible Control Technologies (Step 3) and Identify BART

Based on the reasons outlined in the above discussion, EPC has identified low NO_X burners as being technically feasible. Currently the Mill is using LNB technology consisting of passive combustion control through burner tuning on the Lime Kiln. LNB technology is achieving approximately 50% NO_X control.

EPC believes that the existing LNB technology represents the "top" technically feasible NO_X control technology for the Lime Kiln. 40 CFR Part 51, Appendix Y (IV, D., Step 1, 9) specifically states that:

> *"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. Likewise, if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses in this section."*

Based on the regulatory language provided in 40 CFR Part 51, Appendix Y, EPC believes that the existing LNB technology represents BART, and that the remaining steps in the BART analysis are not required to be completed, by meeting the following criteria:

1. There are no other technically feasible control technologies available for lime kilns other than LNB technology for the abatement of NO_X;
2. NO_X emissions from the Lime Kiln has a minimal impact on the visibility analysis; and
3. The Lime Kiln has a minimal impact on the overall visibility analysis.

8.3 SO_2 BART ANALYSIS

Sulfur dioxide is formed in a lime kiln when fuels containing sulfur are burned. There is sulfur in the lime mud, fuel oil, and in the NCGs (when they are being combusted in the Lime Kiln as a control device). A significant amount of the SO_2 formed during the combustion process in the kiln is removed from the kiln gas stream as the regenerated quicklime in the kiln functions as an "in-situ" scrubbing agent. The "in-situ" SO_2 scrubbing is augmented by the existing venturi scrubber, which operates using weak wash and/or caustic as a scrubbing medium.

8.3.1 Identification of All Available Retrofit Control Technologies (Step 1)

Based on the data review process described previously, a list of potential technologies for controlling SO_2 emissions from Lime Kiln was formulated. EPC identified the following potential control technologies:

- Low Sulfur Fuels;
- Wet Scrubbing;
- Dry Scrubbing; and
- Semi-dry Scrubbing.

8.3.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down BART analysis is an evaluation of the technical feasibility of each of the identified control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility with respect to the Lime Kiln.

8.3.2.1 Low Sulfur Fuels

The mechanism by which lower sulfur fuels function to control SO_2 emissions was described previously in Section 4.3.2.1.

As described previously, the primary purpose of the Lime Kiln is to convert lime mud to lime and to serve as the back-up control device for the combustion of NCGs. Both lime mud and NCGs contain sulfur that can contribute to SO_2 emissions. Although No. 6 fuel oil is fired in order to raise the Lime Kiln temperature, the sulfur content of the fuel is substantially less than the sulfur content of the other materials and its contribution to overall SO_2 emissions cannot be measured because the Lime Kiln has inherently low SO_2 emissions (less than 5 tpy) due to the alkalinity of the kiln itself.

However, if an assumption was made that the 5 tpy of SO_2 emissions from the Lime Kiln were due to the combustion of No. 6 fuel oil (which is not accurate), then a theoretical evaluation can be made to determine whether switching to burn only natural gas or No. 2 fuel oil would be considered cost effective. Although it is technically feasible to evaluate switching to lower sulfur fuels, the calculation is theoretical and would not ultimately lead to lower SO_2 emissions due to the sulfur load from the lime mud and NCGs. <u>As a result, EPC has not further evaluated switching to lower sulfur fuels for the Lime Kiln.</u>

8.3.2.2 Wet Scrubbing

The mechanism by which wet scrubbing functions to control SO_2 emissions was described previously in Section 4.3.2.2. As discussed previously, the Lime Kiln is equipped with a venturi scrubber that utilizes weak wash and/or caustic as a scrubbing media that provides control of PM and acid gases. <u>Therefore EPC considers this control to be technically feasible and is already in place.</u>

8.3.2.3 Dry Scrubbing

The mechanism by which dry scrubbing functions to control SO_2 emissions was described previously in Section 4.3.2.3.

No application of this technology on a Lime Kiln was identified in our research of potential control technologies. <u>As a result, this is not a technically feasible control option for the Lime Kiln.</u>

8.3.2.4 Semi-dry Scrubbing

The mechanism by which semi-dry scrubbing functions to control SO_2 emissions was described previously in Section 4.3.2.3.

No applications of this technology on a Lime Kiln was identified in our research of potential control technologies. As a result, this is not a technically feasible control option for the Lime Kiln.

8.3.3 Evaluate Control Effectiveness of Remaining Technically Feasible Control Technologies (Step 3) and Identify BART

Based on the reasons outlined in the above discussion, EPC has identified the use of wet scrubbing as technically feasible for the Lime Kiln. Currently, the Mill uses a venturi scrubber with weak wash and/or caustic as a scrubbing media to achieve approximately 99% control of SO_2.

EPC believes that the existing wet scrubber represents the "top" technically feasible SO_2 control technology for the Lime Kiln. 40 CFR Part 51, Appendix Y (IV, D., Step 1, 9) specifically states that:

> *"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. Likewise, if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses in this section."*

Based on the regulatory language provided in 40 CFR Part 51, Appendix Y, EPC believes that the existing wet scrubbing technology represents BART, and that the remaining steps in the BART analysis are not required to be completed, by meeting the following criteria:

1. SO_2 emissions for the BART Baseline period from the Lime Kiln are less than 5 tpy;
2. There are no other technically feasible control technologies available for lime kilns other than wet scrubbing technology for the abatement of SO_2;
3. SO_2 emissions from the Lime Kiln has a minimal impact on the visibility analysis; and
4. The Lime Kiln has a minimal impact on the overall visibility analysis.

8.4 PM_{10} BART ANALYSIS

Particulate emissions from the Lime Kiln consists primarily of dust entrained from the combustion section of the kiln. This dust consists of sodium salts, calcium carbonate and calcium oxide. The sodium salt emissions result primarily from sodium compounds that are retained in the lime mud due to inefficient washing, while the calcium particulates result principally from entrainment. Thus, the particulate emissions are affected by the efficiency of the mud washing system and the gas velocity and turbulence in the kiln (EPA 1976a).

The typical first step in the BART analysis is the identification of all available retrofit control options. However, 40 CFR Part 51, Appendix Y (IV, C) identifies an exception to the BART analysis for VOC and PM sources subject to Maximum Achievable Control Technology (MACT) standards under Section 112 of the Clean Air Act. Specifically, Appendix Y states that:

> *"We believe that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without identifying control options that would cost many thousands of dollars per ton. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, you may rely on the MACT standards for the purposes of BART."*

The Lime Kiln is subject to 40 CFR Part 63, Subpart MM – "MACT II" with a compliance date of March 13, 2004. The Lime Kiln is in compliance with the PM standard that was established under MACT II. EPC has reviewed the RBLC database and believes that there are two control technologies that represent the most stringent PM control: (1) ESP and (2) venturi scrubber.

Both ESPs and venturi scrubbers have been used to control particulate emissions from lime kilns. While both are capable of a high degree of particulate removal, the issue of which device represents the best system of emission reduction is clouded due to the presence of SO_2 in the lime kiln flue gas due to the incineration of NCGs. The incineration of NCGs in the Lime Kiln places a greater SO_2 load on the kiln. Unlike an ESP, the venturi scrubber reduces emissions of SO_2 as well as particulate as described in the SO_2 BART analysis section above.

<u>EPC has concluded that the existing venturi scrubber represents BART for PM control based on the following key issues:</u>

1. EPC has maintained compliance with the MACT II PM emission limit using the existing Venturi Scrubber control device; and
2. The use of an ESP would not control SO_2 emissions like the venturi scrubber currently does. The implementation of the ESP for particulate matter control on the Lime Kiln would have a negative environmental impact as there could be an increase in SO_2 emissions from the Lime Kiln when compared to the use of the venturi scrubber.

ATTACHMENT A –
AIR QUALITY MODELING PROTOCOL – BART EXEMPTION MODELING and SUPPORTING INFORMATION

September 14, 2006

Asad Khan
Michigan Department of Environmental Quality
Strategy Development Unit - Air Quality Division
525 West Allegan Street
Lansing, Michigan 48909

Re: NewPage Corporation – Escanaba Paper Company
BART Emissions Inventory and Proposed Visibility Modeling Methodology

Dear Mr. Khan:

NewPage Corporation's Escanaba Paper Company (EPC) has submitted a letter on August 31, 2006 to the Michigan Department of Environmental Quality (MDEQ) that outlined EPC's proposed approach to comply with the Best Available Retrofit Technology (BART) requirements of the Regional Haze rule. In the August 31, 2006 letter, EPC committed to providing MDEQ with an emissions inventory of Visibility Impairing Pollutants (VIP) for all BART eligible emission units at the Mill. For your reference, the BART eligible emissions units at the Mill are the:

- No. 8 Power Boiler;
- No. 9 Bark Boiler;
- No. 10 Recovery Boiler;
- Smelt Dissolving Tank, and;
- Lime Kiln.

In accordance with the August 31, 2006 letter, the emissions inventory of VIP from the BART eligible units is included herein. In addition, the proposed approach to the visibility modeling study that EPC will conduct as part of the BART compliance effort is provided.

BART Emissions Inventory

EPC has compiled the BART emissions inventory of VIP based on the highest 24-hour average actual emissions of SO_2, NO_X, and filterable and condensable $PM_{10}/PM_{2.5}$ for each BART eligible source at the Mill. EPC created the emissions inventory using known maximum production data (often equivalent to the emissions units' capacity) along with emission factors derived from the following information, as necessary and available:

- Annual emissions statements;
- Historic Mill emission factors;

- Site-specific stack test data;
- NCASI Technical Bulletins; and
- USEPA publications (i.e., AP-42), and

The complete unit by unit emissions inventory is included as attachment A to this letter.

Proposed Visibility Modeling Methodology

EPC will conduct visibility modeling analyses as part of the BART compliance effort for the Mill. EPC will use the modeling methodologies outlined in the "*Single Source Modeling to Support Regional Haze BART Modeling Protocol*" document released by the Lake Michigan Air Directors Consortium for the Midwest Regional Planning Organization (Midwest RPO) on March 21, 2006. These modeling procedures have been used by MDEQ in a preliminary analysis of the EPC mill. EPC will use the CALMET meteorological data developed by the Midwest RPO for 2002, 2003 and 2004 and will consider visibility impacts for all Class I areas within 300 km of the Mill.

EPC proposes to deviate from the Midwest RPO protocol with regard to the calculation of natural background visibility levels. The Midwest RPO protocol uses an approach that considers the natural background levels equivalent to the 20% best days per year for each Class I area. An alternative to this approach is to use the USEPA recommendation of natural background visibility levels equivalent to an annual average, rather than the 20% best days of the year. The USEPA recommendation is based on a July 2006 memo from Joseph W. Praise, Group Leader of the Geographic Strategies Group to USEPA Region IV addressing background visibility. In the memo, USEPA clarifies that they never intended to limit States to the use of the 20% best visibility days for the purposes of determining a source's impact on visibility. EPC proposes to use a natural background value that is equivalent to the average annual visibility conditions for each Class I area within 300 km of the Mill, which is consistent with the USEPA guidance. This approach has been widely accepted by States, USEPA, and Federal Land Managers (FLMs) in the southeastern US.

EPC will determine if the combined visibility impacts from the BART eligible sources at the Mill cause a visibility change of 0.5 deciview or more on a 98th percentile basis per modeled year. If the visibility impacts from the BART eligible sources at the Mill are below this threshold, EPC will request that MDEQ exempt the Mill from any further analysis to comply with BART, since the Mill would not be causing or contributing to visibility impairment. If the visibility impacts from the Mill are above this threshold, EPC proposes to use the same modeling methodology to support the BART engineering analysis as necessary.

EPC anticipates that the results of the exemption modeling analysis in Section II will be known by mid October, pending MDEQ's timely review and approval of the emissions inventory and comments regarding EPC's proposed visibility modeling methodology. Please contact me at (906) 233-2337 if you have any questions or require any additional information concerning the attached BART emissions inventory or the proposed visibility modeling methodology.

Sincerely,
Escanaba Paper Company

Steve List
Environmental, Health and Safety Manager

Attachments

cc: Mike Faust – EPC
Theresa Walker – MDEQ
James Haywood – MDEQ
Dan Holland – All4 Inc.
Tom Wickstrom – All4 Inc.

Attachment A – BART Emissions Inventory

Table A-1
NewPage Corporation - Escanaba Paper Company
Escanaba, MI Mill
BART Emission Inventory
No. 8 Power Boiler - Short Term Emission Rates

Pollutant	Emission Factor	Emission Factor Units	Emission Factor Source	Short Term Emission Rate	
				lb/hr	*g/s*
SO_2	149.150	lb/1000 gal	USEPA AP-42 Table 1.3-1 for Distillate Oil (S = 0.95)	384.8	48.5
NO_X[a]	0.628	lb/MMBtu	CEMS data	293.3	37.0
Total PM_{10}	8.670	lb/1000 gal	MAERS database/AP-42	N/A	N/A
Filterable $PM_{2.5}$	5.645	lb/1000 gal	Ratio of $PM_{2.5}$ to PM_{10} (65%) from USEPA AP-42 Table 1.3-5 for uncontrolled oil firing. 7.4% is assumed to be Elemental Carbon (EC), based on emissions data found in Table 6 of the draft 2002 USEPA document "Catalog of Global Emissions Inventory Tools for Black Carbon" for industrial petroleum combustion.	14.6	1.8
Filterable $PM_{2.5-10}$	3.025	lb/1000 gal	Difference between $PM_{2.5}$ and MAERS PM10 emission rate	7.8	1.0
Condensable PM	1.500	lb/1000 gal	USEPA AP-42 Table 1.3-2	3.9	0.5

Throughput Data

Fuel Oil	43	gal/min
Natural Gas	467	MMBtu/hr

a - NOX emission rate was revised in January 2007.

Table A-2
NewPage Corporation - Escanaba Paper Company
Escanaba, MI Mill
BART Emission Inventory
No. 9 Bark Boiler - Short Term Emission Rates

Pollutant	Emission Factor	Emission Factor Units	Emission Factor Source	Short Term Emission Rate	
				lb/hr	*g/s*
SO_2	0.032	lb/MMBtu	Mill Emission Factor (9/4/92 & 6/13/95)	11.5	1.5
NO_X[a]	0.22	lb/MMBtu	2007 Stack Test	79.2	10.0
Total PM_{10}	0.117	lb/MMBtu	Mill Emission Factor (1/20/98, 10/22/98 & 2/21/05) Ratio of EPA PM to PM_{10} for woodwaste.	N/A	N/A
Filterable $PM_{2.5}$	0.117	lb/MMBtu	Ratio of $PM_{2.5}$ to PM_{10} (100%) from USEPA AP-42 Table 1.6-5 for Bark Boilers controlled by a scrubber. 9.3% is assumed to be Elemental Carbon (EC), based on emissions data found in Table 6 of the draft 2002 USEPA document "Catalog of Global Emissions Inventory Tools for Black Carbon" for industrial wood combustion.	42.1	5.3
Filterable $PM_{2.5-10}$	0	lb/MMBtu	Difference between $PM_{2.5}$ and PM_{10} emission rate	0.0	0.0
Condensable PM	0.003	lb/MMBtu	Mean value from NCASI Technical Bulletin 898 Table 4.5, Mill H (Bark/gas/oil firing boiler)	1.1	0.1

Throughput Data
Full load 360 MMBtu/hr

a - NOX emission rate was revised in January 2007.

Table A-3
NewPage Corporation - Escanaba Paper Company
Escanaba, MI Mill
BART Emission Inventory
No. 10 Recovery Furnace - Short Term Emission Rates

Pollutant	Emission Factor	Emission Factor Units	Emission Factor Source	Short Term Emission Rate	
				lb/hr	*g/s*
SO_2	0.025	lb/ton BLS	Mill Emission Factor (3/14/00, 3/15/00 & 9/2/04)	1.9	0.2
NO_X	2.030	lb/ton BLS	Mill Emission Factor (8/16/90, 6/19/90, 9/17/91, 9/18/91, 4/30/92, 6/26/95, 3/11/97, 3/14/00, 3/15/00, & 9/2/04)	156.5	19.7
Total PM_{10}	0.511	lb/ton BLS	Mill Emission Factor - NCASI TB884,898 Summary Data for $PM_{10}/PM_{2.5}$ ratios to Method 5 (3/14/00, 3/15/00, 3/24/04 & 9/2/04).	N/A	N/A
Filterable $PM_{2.5}$	0.460	lb/ton BLS	Ratio of $PM_{2.5}$ to PM_{10} (90%) from USEPA AP-42 Table 10.2-3 for NDCE Recovery Furnaces controlled by an ESP. 1.53% is assumed to be Elemental Carbon (EC), based on emissions data found in USEPA's CMAQ speciation database.	35.5	4.5
Filterable $PM_{2.5-10}$	0.051	lb/ton BLS	Difference between $PM_{2.5}$ and PM_{10} emission rate	3.9	0.5
Condensable PM	0.063	lb/ton BLS	Median value from NCASI Technical Bulletin 884 Table 4.12	4.9	0.6

Throughput Data

Full load 77.083 tons BLS/hr

Table A-4
NewPage Corporation - Escanaba Paper Company
Escanaba, MI Mill
BART Emission Inventory
Smelt Dissolving Tank - Short Term Emission Rates

Pollutant	Emission Factor	Emission Factor Units	Emission Factor Source	Short Term Emission Rate	
				lb/hr	*g/s*
SO_2	0.016	lb/ton BLS	Mill Emission Factor (NCASI Technical Bulletin 646 Table 16-18)	1.2	0.2
Total PM_{10}	0.072	lb/ton BLS	Mill Emission Factor - NCASI TB884,898 Summary Data for $PM_{10}/PM_{2.5}$ ratios to Method 5 (2/14-15/05)	N/A	N/A
Filterable $PM_{2.5}$	0.065	lb/ton BLS	Ratio of $PM_{2.5}$ to PM_{10} (90.8%) from USEPA AP-42 Table 10.2-7 for Smelt Dissolving Tanks controlled by a scrubber.	5.0	0.6
Filterable $PM_{2.5-10}$	0.007	lb/ton BLS	Difference between $PM_{2.5}$ and PM_{10} emission rate	0.5	0.1
Condensable PM	0.014	lb/ton BLS	NCASI Technical Bulletin 884 Table 4.15	1.1	0.1

Throughput Data
Full load 77.083 tons BLS/hr

Table A-5
NewPage Corporation - Escanaba Paper Company
Escanaba, MI Mill
BART Emission Inventory
Lime Kiln - Short Term Emission Rates

Pollutant	Emission Factor	Emission Factor Units	Emission Factor Source	Short Term Emission Rate	
				lb/hr	*g/s*
SO_2	0.042	lb/ton CaO	Mill Emission Factor (6/21/95 & 9/3/04)	0.6	0.1
NO_X	1.150	lb/ton CaO	Mill Emission Factor - NCASI Emission Factor for Residual Fuel Oil (i.e., No. 6 Fuel Oil)	15.3	1.9
Total PM_{10}	0.393	lb/ton BLS	Mill Emission Factor - NCASI TB884,898 Summary Data for $PM_{10}/PM_{2.5}$ ratios to Method 5 (6/20/95, 12/20/00, 12/21/00 & 9/3/04).	N/A	N/A
Filterable $PM_{2.5}$	0.369	lb/ton BLS	Ratio of $PM_{2.5}$ to PM_{10} (93.8%) from USEPA AP-42 Table 10.2-5 for Lime Kilns controlled by a venturi scrubber.	4.9	0.6
Filterable $PM_{2.5\text{-}10}$	0.024	lb/ton BLS	Difference between $PM_{2.5}$ and PM_{10} emission rate	0.3	0.0
Condensable PM	0.188	lb/ton BLS	Median value from NCASI Technical Bulletin 884 Table 4.13	2.5	0.3

Throughput Data
Full load 13.33 tons CaO/hr

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

JUL 19 2006

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

MEMORANDUM

SUBJECT: Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations

FROM: Joseph W. Paisie, Group Leader Barb Driscoll for
Geographic Strategies Group (MC 504-2)

TO: Kay Prince, Branch Chief
EPA, Region 4

In July 2005, EPA issued BART Guidelines that provide guidance to the States in making BART determinations for large power plants and other BART sources. In the BART Guidelines, we described several approaches that States could use to determine whether a source should be subject to review for BART, or whether it should be exempt from the BART requirements. As you know, BART applies to existing sources of a certain type, age, and size that "emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any [Class I] area." CAA §169A(b)(2)(A). One approach discussed in the Guidelines for determining that a source does not meet the threshold test for BART is to use the air quality model CALPUFF.

We understand that many States and Regional Planning Organizations (RPOs) are currently considering the use of CALPUFF for making BART determinations. We have received a question asking whether States can, or should, allow sources to use CALPUFF to estimate visibility impacts on a pollutant specific basis, or whether EPA intended CALPUFF to be used to model a source's visibility impacts based on its total emissions of visibility-impairing pollutants. We have also received a question regarding the process for estimating natural background conditions, one of the factors used to estimate a source's impact on visibility. This memo addresses these two questions.

Pollutant-Specific CALPUFF Analyses

Because of the complexity and nonlinear nature of atmospheric chemistry and chemical transformation among pollutants, EPA does not generally recommend that CALPUFF be used on a pollutant specific basis to determine whether a source meets the threshold test for BART. In certain situations, however, it may be appropriate to do just that. For example, if a State chooses to adopt the Clean Air Interstate Rule (CAIR) program to address emissions of SO_2 and NO_x from electric generating units (EGUs), the CAIR may satisfy the requirements for BART for these pollutants from these sources. However, the State must determine whether its BART-eligible EGUs are subject to review under BART for direct emissions of particulate matter (PM). Because the task of predicting the impacts of PM on visibility is a relatively straight-forward exercise, unlike predicting the impacts of SO_2 and NO_x, we would recommend the use of CALPUFF on a pollutant specific basis to model only the impact of PM emissions on visibility. Using the results of such an analysis, States may then determine whether a source should be subject to review for PM controls, or alternatively, that the source is not subject to BART for PM.

Estimating Natural Visibility Conditions

The BART Guidelines explain that States should estimate a source's impact on visibility by "calculat[ing] daily visibility values for each receptor as the change in deciviews compared against natural visibility conditions." 70 Fed. Reg. 39104, 39162 (July 6, 2005). EPA has provided guidance to the States specifically for the complex task of estimating natural visibility conditions, *see* "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule," EPA-454/B-3-005 (September 2003), but neither the BART Guidelines nor the guidance described above specify whether for purposes of determining whether a source is subject to BART, States should use annual values in calculating natural background visibility estimates or some other averaging period. The preamble to the BART Guidelines, however, states that the BART Guidelines suggest that States use a natural visibility baseline for the 20% best days for determining a source's impact on visibility.

We are clarifying here that the EPA did not intend to limit States to the use of the 20% best visibility days for this comparison through the statement in the preamble describing the BART Guidelines. States may use the 20% best visibility days or an annual average. The BART Guidelines allow for this flexibility, and we believe that either value would allow for States to determine appropriately whether a source is reasonably anticipated to cause or contribute to any impairment in visibility.

I am requesting that in your role as sublead Region for PM and Regional Haze, you transmit this memo to the other Regions. I would like to thank you in advance for your assistance.

If you have any questions about either of these issues, please contact either Kathy Kaufman or Todd Hawes in my office.

ATTACHMENT B –
SUMMARY OF BART EXEMPTION MODELING RESULTS

ATTACHMENT C –
CONTROL COST SPREADSHEETS

TABLE C-1
ESCANABA PAPER COMPANY
BART EVALUATION CAPITAL AND ANNUALIZED COSTS
NO. 8 BOILER NO_x CONTROL
SELECTIVE CATALYTIC REDUCTION (SCR)

CAPITAL COSTS

	COST ITEM	FACTOR	NO. 8 BOILER COST ($)
	Costs to Purchase and Install Equipment		
	<u>Purchased Equipment Costs</u>		
(a)	catalyst		$511,000
(c)	Platform materials to support the new equipment		$75,000
(c)	New fan		$500,000
(c)	New stack		$200,000
(c)	Electrical for the fan		$300,000
	Purchased Equipment Costs Subtotal	*A*	*$1,586,000*
(b)	Instrumentation	0.100 A	$158,600
(b)	Sales taxes	0.030 A	$47,580
(b)	Freight	0.050 A	$79,300
	Total Purchased Equipment Cost	*B*	*$1,871,480*
	<u>Direct Installation Costs</u>		
(c)	Installation of SCR system including urea storage and delivery system, platform, demolition of old stack, demo of old fan, installation of new fan, new stack, foundations and supports, electrical, piping, insulation, and painting	1.85 B	$3,462,238
	Direct Installation Cost	*C*	*$3,462,238*
	Total Direct Cost	*D*	*$5,333,718*
	<u>Indirect Costs (Installation)</u>		
(b)	General Facilities	0.05 D	$266,686
(b)	Engineering and Home Office Fees	0.10 D	$533,372
(b)	Process Contingency	0.05 D	$266,686
(b)	Project Contingency	0.15 (D+Gen Fac+Eng+Proc Cont)	$960,069
(b)	Total Plant Cost	(D+Gen Fac+Eng+Proc Cont+Proj Cont)	$7,360,531
(b)	Preproduction Cost	0.02 Total Plant Cost	$147,211
	Total Capital Investment (TCI)...	(Tot Plt Cost+Preprod Cost)	*$7,507,741*

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
	Annual Operating Costs			
	<u>*Direct Annual Costs*</u>			
	<u>*Operating Labor*</u>			
(c)	Labor, one employee	0.5 hours/shift	$56.00 per hour	$27,594
	<u>*Maintenance*</u>			
(b)	Maintenance Labor and Materials	0.015 TCI		$112,616
	<u>*Utilities*</u>			
(a),(c)	Reagent	47304 gal/yr	$1.25 per gal	$59,130
(a),(c)	Electricity	0.1 KWh	$0.05 per kWh	$42
(a)	Catalyst replacement	22 m^3	$298,000 per 12,000 hours	$195,786
(a),(c)	Spent catalyst disposal (assuming 1000	5.1 tons of catalyst	$18.00 per ton per 12,000 hours	$60
	Total Direct Annual Costs		*DAC*	*$395,228*
	<u>*Indirect Annual Costs*</u>			
(b)	Overhead	60% of sum of operating & maintenance costs		$84,128
(b)	Administrative Charges	2% of TCI		$150,155
(b)	Property Taxes	1% of TCI		$75,077
(b)	Insurance	1% of TCI		$75,077
	Total Indirect Annual Costs		*IAC*	*$384,436*
	Total Annual O&M Costs		*O&M*	*$779,664*
	Cost Effectiveness			
	Expected lifetime of equipment, years	10		
	Interest rate, %/yr	10.0%		
	Capital recovery factor	0.163		
	Total capital investment cost	$7,507,741		
	Annualized capital investment cost			*$1,221,850*
	Total Annualized Cost (including O&M)			*$2,001,514*
	Cost Effectiveness			
	Uncontrolled Emissions (Worst-Case Scenario if current FGR control is decommissioned and NOT in Use)	143.2 tons NOx/yr		*NOx Evaluation*
	Annual Cost/Ton Removed	128.9 tons NOx/yr	90% NOx removal	*$15,527*
	Incremental Cost Effectiveness			
	Controlled Emissions if the Mill were to Utilize current FGR on a Year-Round Basis and Also Install SCR	115.7 tons NOx/yr		*NOx Evaluation*
	Annual Cost/Ton Removed	104.1 tons NOx/yr	90% NOx removal	*$19,224*

Notes:

(a) Cost information obtained from Mr. Ed Schindler at Combustion Components Associates (CCA) on December 16, 2006.
(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.
(c) Cost information estimated by the Mill. Direct installation costs were approximated using a combination of Mill historical information and experience with multiple capital equipment installations. This experience indicates that the total capital investment should equal four times the purchased capital equipment cost because of the complexity of the installation that would need to occur at high elevations. Operating labor and maintenance costs were estimated using an assumption of one employee per shift, 3 shifts per day, and 90% utilization.

TABLE C-2
ESCANABA PAPER COMPANY
BART EVALUATION CAPITAL AND ANNUALIZED COSTS
NO. 8 BOILER NO_x CONTROL
LOW NO_x BURNERS

CAPITAL COSTS

COST ITEM	FACTOR	NO. 8 BOILER COST ($)
Costs to Purchase and Install Equipment		
Purchased Equipment Costs		
(a) Burners		$198,290
Purchased Equipment Costs Subtotal	*A*	*$198,290*
(b) Instrumentation	0.100 A	$19,829
(b) Sales taxes	0.030 A	$5,949
(b) Freight	0.050 A	$9,915
Total Purchased Equipment Cost	*B*	*$233,982*
Direct Installation Costs		
(c) Guns, piping, electrical, refractory, misc.	1.14 B	$266,740
Direct Installation Cost	*C*	*$266,740*
Total Direct Cost	*D*	*$500,722*
Indirect Costs (Installation)		
(b) General Facilities	0.05 D	$25,036
(b) Engineering and Home Office Fees	0.10 D	$50,072
(b) Process Contingency	0.05 D	$25,036
(b) Project Contingency	0.15 (D+Gen Fac+Eng+Proc Cont)	$90,130
(b) Total Plant Cost	(D+Gen Fac+Eng+Proc Cont+Proj Cont)	$690,996
(b) Preproduction Cost	0.02 Total Plant Cost	$13,820
Total Capital Investment (TCI)	Tot Plt Cost+Pre Prod Cost	*$704,816*

ANNUALIZED COSTS

COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
Annual Operating Costs			
Direct Annual Costs			
Operating Labor			
(c) Labor, one employee	0.5 hours/shift	$56.00 per hour	$27,594
Maintenance			
(b) Maintenance Labor and Materials	0.015 TCI		$10,572
Utilities			
Total Direct Annual Costs		*DAC*	*$38,166*
Indirect Annual Costs			
(b) Overhead	60% of sum of operating & maintenance costs		$22,900
(b) Administrative Charges	2% of TCI		$14,096
(b) Property Taxes	1% of TCI		$7,048
(b) Insurance	1% of TCI		$7,048
Total Indirect Annual Costs		*IAC*	*$51,092*
Total Annual O&M Costs		*O&M*	*$89,259*
Cost Effectiveness			
Expected lifetime of equipment, years	10		
Interest rate, %/yr	10.0%		
Capital recovery factor	0.163		
Total capital investment cost	$704,816		
Annualized capital investment cost			*$114,706*
Total Annualized Cost (including O&M)			*$203,964*
Cost Effectiveness			
Uncontrolled Emissions (Worst-Case Scenario if current FGR control is decommissioned and NOT in Use)	143.2 tons NOx/yr		*NOx Evaluation*
Annual Cost/Ton Removed	57.3 tons NOx/yr	40% NOx removal	*$3,560*
Incremental Cost Effectiveness			
Controlled Emissions if the Mill were to Utilize current FGR on a Year-Round Basis and Also Install LNB	115.7 tons NOx/yr		
Annual Cost/Ton Removed	46.3 tons NOx/yr	40% NOx removal	*NOx Evaluation* *$4,408*

Notes:

(a) Cost information obtained from Coen as part of the Mill's April, 2003 engineering study evaluated by Mr. Joe Peterson.
(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.
(c) Cost information estimated by the Mill. Direct installation costs were approximated using a combination of Mill historical information and experience with multiple capital equipment installations. This experience indicates that the total capital investment should equal three times the purchased capital equipment cost (for relatively simple installations such as this). Operating labor and maintenance costs were estimated using an assumption of one employee per shift, 3 shifts per day, and 90% utilization.

TABLE C-3
ESCANABA PAPER COMPANY
BART EVALUATION CAPITAL AND ANNUALIZED COSTS
NO. 8 BOILER NO_X CONTROL
SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

CAPITAL COSTS

	COST ITEM	FACTOR	NO. 8 BOILER COST ($)
Costs to Purchase and Install Equipment			
Purchased Equipment Costs			
(a)	SNCR urea-based system including storage and delivery		$750,000
(c)	Platform materials to support the new equipment		$75,000
(c)	Controls		$250,000
(c)	Contingency		$100,000
	Purchased Equipment Costs Subtotal	*A*	*$1,175,000*
(b)	Sales taxes	0.030 A	$35,250
(b)	Freight	0.050 A	$58,750
	Total Purchased Equipment Cost	*B*	*$1,269,000*
Direct Installation Costs			
(c)	Installation of platform, foundations and supports, electrical, piping, and insulation	1.85 B	$2,347,650
	Direct Installation Cost	C	*$2,347,650*
	Total Direct Cost	*D*	*$3,616,650*
Indirect Costs (Installation)			
(b)	General Facilities	0.05 D	$180,833
(b)	Engineering and Home Office Fees	0.10 D	$361,665
(b)	Process Contingency	0.05 D	$180,833
(b)	Project Contingency	0.15 (D+Gen Fac+Eng+Proc Cont)	$650,997
(b)	Total Plant Cost	(D+Gen Fac+Eng+Proc Cont)+Proj Cont)	$4,990,977
(b)	Preproduction Cost	0.02 Total Plant Cost	$99,820
	Total Capital Investment (TCI)..	(Tot Plant Cost+Pre Prod Cost)	*$5,090,797*

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ANNUALIZED COSTS

	COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
Annual Operating Costs				
Direct Annual Costs				
Operating Labor				
(c)	Labor, one employee	0.5 hours/shift	$56.00 per hour	$27,594
Maintenance				
(b)	Maintenance Labor and Materials	0.015 TCI		$76,362
Utilities				
(c),(d)	Urea reagent	2.2 gal/hr	$1.25 per gal	$21,795
(c),(d)	Fresh Water usage	10.1 gal/hr	$0.14 per 1000 gal	$10,767
(c),(d)	Additional fuel requirement due to loss o	0.1 MMBtu/hr	$4.80 per MMBtu	$3,219
(c),(d)	Electricity	2.3 KWh	$0.05 per kWh	$959
	Total Direct Annual Costs		*DAC*	*$140,696*
Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		$62,374
(b)	Administrative Charges	2% of TCI		$101,816
(b)	Property Taxes	1% of TCI		$50,908
(b)	Insurance	1% of TCI		$50,908
	Total Indirect Annual Costs		*IAC*	*$266,005*
	Total Annual O&M Costs		*O&M*	*$406,702*
	Cost Effectiveness			
	Expected lifetime of equipment, years	10		
	Interest rate, %/yr	10.0%		
	Capital recovery factor	0.163		
	Total capital investment cost	$5,090,797		
	Annualized capital investment cost			*$828,504*
	Total Annualized Cost (Including O&M)			*$1,235,205*
Cost Effectiveness				
Uncontrolled Emissions (Worst-Case Scenario if current FGR control is decommissioned and NOT in Use)		143.2 tons NOx/yr		*NOx Evaluation*
Annual Cost/Ton Removed		28.6 tons NOx/yr	20% NOx removal (guarantee from vendor)	*$43,120*
Incremental Cost Effectiveness				
Controlled Emissions if the Mill were to Utilize current FGR on a Year-Round Basis and Also Install SNCR		115.7 tons NOx/yr		
Annual Cost/Ton Removed		23.1 tons NOx/yr	20% NOx removal (guarantee from vendor)	*NOx Evaluation* *$53,387*

Notes:

(a) Cost information obtained from Mr. Ed Schindler at CCA, Inc. via telephone conversation on December 6, 2006 for the SNCR equipment.
(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.
(c) Cost information estimated by the Mill. Direct installation costs were approximated using a combination of Mill historical information and experience with multiple capital equipment installations. This experience indicates that the total capital investment should equal four times the purchased capital equipment cost because of the complexity of the installation that would need to occur at high elevations. Operating labor and maintenance costs were estimated using an assumption of one employee per shift, 3 shifts per day, and 90% utilization.
(d) Usage information estimated based on other similar SNCR installations.

TABLE C-4
ESCANABA PAPER COMPANY
BART EVALUATION ANNUAL COSTS
NO. 8 POWER BOILER NOx CONTROL
UTILIZING EXISTING FLUE GAS RECIRCULATION SYSTEM YEAR-ROUND

2005 heat input during the ozone season	468,168	MMBtu during ozone season
2005 heat input during the rest of the year	633,587	MMBtu during the rest of the year
2006 emission factor during the ozone season	0.21	lb/MMBtu for oil & gas cofiring during the ozone season
2006 emission factor during the rest of the year	0.26	lb/MMBtu for oil & gas cofiring during the rest of the year
Estimated NOx during the ozone control season	49.2	tons
Estimated NOx during the rest of the year	82.4	tons
Estimated NOx if FGR was not in operation at all	143.2	tons
Estimated NOx if FGR was operated year-round	115.7	tons
Difference in NOx emissions with and without year-round FGR	15.8	tons NOx reduction
Annualized $ to install a new fan to support the system (see below)	$706,626	per year
Cost per ton of NOx removal	$44,611	**Incremental cost per ton of NOx removed**

Notes:

The 2006 calendar year was not yet completed at the time of these calculations. As a result, heat input data for 2005 was used to estimate emissions for the purposes of these cost calculations. Since fuel oil was introduced to the boiler in 2006, partial-year CEMS data for fuel oil and natural gas cofiring was used to evaluate the change in emissions with FGR on and off. The CEMS data was taken from May 1 - Sep 30 for the ozone control season with FGR on, and from Oct 1 - Dec 5 for the rest of the year with FGR off and the average emission factors and estimated NOx emissions were calculated using these time periods. This was determined to be a conservative approach since a slight reduction in NOx was observed when cofiring fuel oil and natural gas with and without FGR. It should be noted that zero NOx reductions were observed during periods of time when only fuel oil or only natural gas was being fired and this is a common operating scenario. As a result, actual NOx reductions that would occur if utilizing FGR year-round are expected to be less than what has been conservatively estimated here and because the reductions would only be observed during periods of time when fuel oil and natural gas would be cofired together.

CAPITAL COSTS

	COST ITEM	FACTOR	FGR YEAR-ROUND COST ($)
	Costs to Purchase and Install Equipment		
	Purchased Equipment Costs		
	New fan		$500,000
	Motor and starter		$300,000
	Purchased Equipment Costs Subtotal	*A*	*$800,000*
(a)	Instrumentation	0.100 A	$80,000
(a)	Sales taxes	0.030 A	$24,000
(a)	Freight	0.050 A	$40,000
	Total Purchased Equipment Cost	*B*	*$944,000*
	Direct Installation Costs		
	Demo of old fan, installation of new fan and electrical	1.65 B	$1,557,600
	Direct Installation Cost	C	*$1,557,600*
	Total Direct Cost	*D*	*$2,501,600*
	Indirect Costs (Installation)		
(a)	**Engineering**	0.10 B	$94,400
(a)	**Construction & field expenses**	0.10 B	$94,400
(a)	**Contractor fees**	0.10 B	$94,400
(a)	**Start-up**	0.01 B	$9,440
(a)	**Performance Test**	0.01 B	$9,440
(a)	Contingencies	0.03 B	$28,320
	Total Indirect Cost		*$330,400*
	Total Capital Investment (TCI)		*$2,832,000*

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
	Annual Operating Costs			
	Direct Annual Costs			
	Operating Labor			
	Labor, one employee	0.5 hours/shift	**$56.00 per hour**	***$27,594***
	Maintenance			
	Maintenance Labor	0.5 hours/shift	**$56.00 per hour**	***$27,594***
	Maintenance Materials	100% of maintenance labor		*$27,594*
	Utilities			
	Electricity	assume negligible	$0.05 per kWh	
	Total Direct Annual Costs		*DAC*	***$82,782***
	Indirect Annual Costs			
(a)	**Overhead**	**60% of sum of operating & maintenance costs**		$49,669
(a)	Administrative Charges	2% of TCI		$56,640
(a)	Property Taxes	1% of TCI		$28,320
(a)	**Insurance**	1% of TCI		$28,320
	Total Indirect Annual Costs		*IAC*	***$162,949***
	Total Annual O&M Costs		***O&M***	***$245,731***
	Cost Effectiveness			
	Expected lifetime of equipment, years	10		
	Interest rate, %/yr	10.0%		
	Capital recovery factor	0.163		
	Total capital investment cost	$2,832,000		
	Annualized capital investment cost			***$460,895***
	Total Annualized Cost (including O&M)			***$706,626***

Notes:

(a) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dr1/c_allchs.pdf.

All other costs were estimated by the Mill. Operating labor and maintenance costs were estimated using an assumption of one employee per shift, 3 shifts per day, and 90% utilization.

Direct installation costs were approximated using a combination of Mill historical information and experience with multiple capital equipment installations. This experience indicates that the total capital investment should equal three times the purchased capital equipment cost (for relatively simple installations such as this).

TABLE C-5
ESCANABA PAPER COMPANY
BART EVALUATION ANNUAL COSTS
NO. 8 POWER BOILER SO_2 CONTROL
SWITCHING TO BURN ONLY NATURAL GAS (NO FUEL OIL)

Gas related SO_2 emissions	0.3	2005 TPY
No. 6 Fuel Oil related SO_2 emissions	114.4	2005 TPY
No. 6 Fuel Oil usage	2,556,101	2005 gal
No. 6 Fuel Oil heat value	156,004	2005 Btu/gal
No. 6 Fuel Oil %S	0.57%	2005 %S
SO_2 emission factor (gas)	0.6	lb/MMft^3 (AP-42)
SO_2 emission factor (oil)	89.49	lb/M gal (AP-42), 157*%S
Annual heat input from fuel oil	398,762	MMBtu/yr
Equivalent amount of gas	399	MMft^3 gas equal to heat from fuel oil
SO_2 from equivalent amount of gas	0.12	TPY
Cost of fuel oil	$6.84	per MMBtu (2006 pricing)
Cost of natural gas	$8.05	per MMBtu (2006 pricing)
Theoretical SO_2 removed by switching from fuel oil to natural gas	114.3	TPY (actual oil SO_2 minus equivalent gas SO_2)
Theoretical SO_2 following a switch to only burn natural gas	0.4	TPY
Cost to fire fuel oil	$2,727,532	per year
Cost to fire natural gas instead of fuel oil	$3,210,034	per year
Incremental cost associated with switching from fuel oil to natural gas	$482,502	per year
Cost per ton of SO_2 removal	**$4,222**	**Incremental cost per ton of SO_2 removed**

Notes:

All costs were estimated based on Mill information.

TABLE C-6
ESCANABA PAPER COMPANY
BART EVALUATION ANNUAL COSTS
NO. 8 POWER BOILER SO_2 CONTROL
SWITCHING TO BURN ONLY LOW SULFUR NO. 2 FUEL OIL

Gas related SO_2 emissions	0.3	2005 TPY
No. 6 Fuel Oil related SO_2 emissions	114.4	2005 TPY
No. 6 Fuel Oil usage	2,556,101	2005 gal
No. 6 Fuel Oil heat value	156,004	2005 Btu/gal
No. 2 Fuel Oil heat value	140,000	Assumed Btu/gal
No. 2 Fuel Oil sulfur content	0.05%	2005 %S
SO_2 emission factor (gas)	0.6	lb/MMft^3 (AP-42)
SO_2 emission factor (No. 2 fuel oil)	7.85	lb/Mgal (AP-42), 157*%S
Annual heat input from fuel oil	398,762	MMBtu/yr
SO_2 from No. 2 Fuel Oil	10.0	2005 TPY from No. 2 instead of No. 6 Fuel Oil
Cost of No. 6 Fuel Oil	$6.84	per MMBtu (2006 pricing)
Cost of No. 2 Fuel Oil	$2.30	Per gallon (http://tonto.eia.doe.gov/dnav/pet/pet_pri_dist_dcu_nus_m.htm)
Theoretical SO_2 removed by switching from No. 6 to No. 2 Fuel Oil	104.4	TPY
Cost to fire No. 6 Fuel Oil	$2,727,532	per year
Cost to fire No. 2 Fuel Oil	$6,551,090	per year
Cost difference between No. 6 and No. 2 Fuel Oil	$3,823,558	per year
Annualized $ to install a dedicated No. 2 Fuel Oil system (see below)	$291,246	per year
Total incremental $ per year to switch from No. 6 to No. 2 Fuel Oil	$4,114,804	per year
Cost per ton of SO_2 removal	$39,426	Incremental $ per ton of SO_2 removed

CAPITAL COSTS

	COST ITEM	FACTOR	NO. 2 FUEL OIL SYSTEM COST ($)
	Costs to Purchase and Install Equipment		
	Purchased Equipment Costs		
	No. 2 Fuel Oil storage tank		$150,000
	Piping		$60,000
	Electrical/Pumps		15,000
	Purchased Equipment Costs Subtotal	A	*$225,000*
(a)	Instrumentation	0.100 A	$22,500
(a)	Sales taxes	0.030 A	$6,750
(a)	Freight	0.050 A	$11,250
	Total Purchased Equipment Cost	B	*$265,500*
	Direct Installation Costs		
	Installation of purchased equipment	1.6 B	$424,800
	Direct Installation Cost	C	*$424,800*
	Total Direct Cost	D	*$690,300*
	Indirect Costs (Installation)		
(a)	Engineering	0.10 B	$26,550
(a)	Construction & field expenses	0.10 B	$26,550
(a)	Contractor fees	0.10 B	$26,550
(a)	Start-up	0.01 B	$2,655
(a)	Performance Test	0.01 B	$2,655
(a)	Contingencies	0.03 B	$7,965
	Total Indirect Cost		*$92,925*
	Total Capital Investment (TCI)................		*$783,225*

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
	Annual Operating Costs			
	Direct Annual Costs			
	Operating Labor			
	Labor, one employee	0.5 hours/shift	$56.00 per hour	$27,594
	Maintenance			
	Maintenance Labor	0.5 hours/shift	$56.00 per hour	$27,594
	Maintenance Materials	100% of maintenance labor		$27,594
	Utilities			
	Electricity	assume negligible	$0.05 per kWh	
	Total Direct Annual Costs		*DAC*	*$82,782*
	Indirect Annual Costs			
(a)	Overhead	60% of sum of operating & maintenance costs		$49,659
(a)	Administrative Charges	2% of TCI		$15,665
(a)	Property Taxes	1% of TCI		$7,832
(a)	Insurance	1% of TCI		$7,832
	Total Indirect Annual Costs		*IAC*	*$80,998*
	Total Annual O&M Costs		*O&M*	*$163,780*
	Cost Effectiveness			
	Expected lifetime of equipment, years	10		
	Interest rate, %/yr	10.0%		
	Capital recovery factor	0.163		
	Total capital investment cost	$783,225		
	Annualized capital investment cost			*$127,466*
	Total Annualized Cost (including O&M)			*$291,246*

Notes:

(a) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dr1/c_allchs.pdf.

All other costs were estimated by the Mill. Operating labor and maintenance costs were estimated using an assumption of one employee per shift, 3 shifts per day, and 90% utilization.

Direct installation costs were approximated using a combination of Mill historical information and experience with multiple capital equipment installations. This experience indicates that the total capital investment should equal three times the purchased capital equipment cost (for relatively simple installations such as this).

TABLE C-7
ESCANABA PAPER COMPANY
BART EVALUATION CAPITAL AND ANNUALIZED COSTS
NO. 8 BOILER SO_2 CONTROL
HIGH PRESSURE DROP WET SCRUBBER

CAPITAL COSTS

	COST ITEM	FACTOR	NO. 8 BOILER COST ($)
	Costs to Purchase and Install Equipment		
	Purchased Equipment Costs		
(a)	Venturi, separator, & instrumentation		$597,000
(c)	New stack		$200,000
(c)	Platform materials to support the new equipment		$75,000
(c)	New fan to compensate for loss in pressure across boiler		$500,000
(c)	Electrical		$300,000
	Purchased Equipment Costs Subtotal	*A*	*$1,672,000*
(b)	Instrumentation	0.100 A	included above
(b)	Sales taxes	0.030 A	$50,160
(b)	Freight	0.050 A	$83,600
	Total Purchased Equipment Cost	*B*	*$1,805,760*
	Direct Installation Costs		
(c)	Installation of scrubber and ancillary equipment, demolition of existing fan and stack, installation of platform to support the new equipment at high elevation, installation of new fan, installation of new stack	2.20 B	$3,972,672
(b)	Foundations and supports	0.12 B	$216,691
(b)	Electrical	0.01 B	$18,058
(b)	Piping	0.30 B	$541,728
(b)	Insulation	0.01 B	$18,058
(b)	Painting	0.01 B	$18,058
	Direct Installation Cost	*C*	*$4,785,264*
	Total Direct Cost	*D*	*$6,591,024*
	Indirect Costs (Installation)		
(b)	Engineering	0.10 B	$180,576
(b)	Construction & field expenses	0.10 B	$180,576
(b)	Contractor fees	0.10 B	$180,576
(b)	Start-up	0.01 B	$18,058
(b)	Performance Test	0.01 B	$18,058
(b)	Contingencies	0.03 B	$54,173
	Total Indirect Cost		*$632,016*
	Total Capital Investment (TCI)		*$7,223,040*

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
	Annual Operating Costs			
	Direct Annual Costs			
	Operating Labor			
(c)	Labor, one employee	1 hour/shift	$56.00 per hour	$55,188
	Maintenance			
(c)	Maintenance Labor	1 hour/shift	$56.00 per hour	$55,188
(c)	Maintenance Materials	100% of maintenance labor		$55,188
	Utilities			
(a),(c)	Chemicals	32 lbs/hr NaOH	$420.60 per ton NaOH	$53,056
(a),(c)	Fresh Water usage	54 gpm	$0.14 per 1000 gal	$3,453
(a),(c)	Wastewater Disposal (based on water usage above)	25,544 kgal/yr	$0.20 per 1000 gal	$5,124
(a),(c)	Electricity	884 kWh	$0.05 per kWh	$371,402
	Total Direct Annual Costs		*DAC*	*$598,600*
	Indirect Annual Costs			
(b)	Overhead	60% of sum of operating & maintenance costs		$99,338
(b)	Administrative Charges	2% of TCI		$144,461
(b)	Property Taxes	1% of TCI		$72,230
(b)	Insurance	1% of TCI		$72,230
	Total Indirect Annual Costs		*IAC*	*$388,260*
	Total Annual O&M Costs		*O&M*	*$986,860*
	Cost Effectiveness			
	Expected lifetime of equipment, years	10		
	Interest rate, %/yr	10.0%		
	Capital recovery factor	0.163		
	Total capital investment cost	$7,223,040		
	Annualized capital investment cost			*$1,175,516*
	Total Annualized Cost (Including O&M)			*$2,162,376*
	Uncontrolled Emissions	114.9 tons SO_2/yr		***SO_2 Evaluation***
	Annual Cost/Ton Removed	70.1 tons SO_2/yr	61% SO_2 removal (guarantee from vendor)	*$30,852*

Notes:

(a) Cost information obtained from Turbosonic via email on November 28, 2006.
(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.
(c) Cost information estimated by the Mill. Direct installation costs were approximated using a combination of Mill historical information and experience with multiple capital equipment installations. This experience indicates that the total capital investment should equal four times the purchased capital equipment cost because of the complexity of the installation due to the demolition work and the new equipment installation that would need to occur at high elevations. Operating labor and maintenance costs were estimated using an assumption of one employee per shift, 3 shifts per day, and 90% utilization.

TABLE C-8
ESCANABA PAPER COMPANY
BART EVALUATION CAPITAL AND ANNUALIZED COSTS
NO. 8 BOILER SO_2 CONTROL
DRY SCRUBBER FOLLOWED BY A BAGHOUSE

CAPITAL COSTS

	COST ITEM	FACTOR	NO. 8 BOILER COST ($)
	Costs to Purchase and Install Equipment		
	Purchased Equipment Costs		
(a)	Lime storage tank, loading and delivery system, rotary valves, and blowers		$700,000
(c)	Baghouse system		$500,000
(c)	New stack		$200,000
(c)	Platform materials to support the new equipment		$75,000
(c)	New fan to compensate for loss in pressure across boiler		$500,000
(c)	Baghouse ash handling system		$400,000
(c)	Lime reagent delivery and storage system		$150,000
(c)	Electrical		$300,000
	Purchased Equipment Costs Subtotal	A	*$2,825,000*
(b)	Instrumentation	0.100 A	$282,500
(b)	Sales taxes	0.030 A	$84,750
(b)	Freight	0.050 A	$141,250
	Total Purchased Equipment Cost	B	*$3,333,500*
	Direct Installation Costs		
(c)	Demolition of existing fan and stack, installation of new stack, platform, new fan, baghouse ash handling system, and lime reagent delivery and storage system	1.80 B	$6,000,300
(b)	Foundations and supports	0.12 B	$400,020
(b)	Handling & erection for the dry scrubber and ESP	0.40 B	$1,333,400
(b)	Electrical	0.01 B	$33,335
(b)	Piping	0.30 B	$1,000,050
(b)	Insulation	0.01 B	$33,335
(b)	Painting	0.01 B	$33,335
	Direct Installation Cost	C	*$8,833,775*
	Total Direct Cost	D	*$12,167,275*
	Indirect Costs (Installation)		
(b)	Engineering	0.10 B	$333,350
(b)	Construction & field expenses	0.10 B	$333,350
(b)	Contractor fees	0.10 B	$333,350
(b)	Start-up	0.01 B	$33,335
(b)	Performance Test	0.01 B	$33,335
(b)	Contingencies	0.03 B	$100,005
	Total Indirect Cost		*$1,166,725*
	Total Capital Investment (TCI)....................................		*$13,334,000*

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
	Annual Operating Costs			
	Direct Annual Costs			
	Operating Labor			
(c)	Labor, two employees	3 hours/shift	$56.00 per hour	$331,128
	Maintenance			
(c)	Maintenance Labor	2 hours/shift	$56.00 per hour	$110,376
(c)	Maintenance Materials	100% of maintenance labor		$110,376
	Utilities			
(a),(c)	Chemicals	36 lbs/hr	$88.52 per ton Lime	$12,562
(a),(c)	Fresh Water usage	26 gpm	$0.14 per 1000 gal	$1,663
(a),(c)	Waste disposal	90 lbs/hr	$18.00 per ton	$6,386
(a),(c)	Electricity	261 KWh	$0.05 per kWh	$109,697
	Total Direct Annual Costs		*DAC*	*$682,188*
	Indirect Annual Costs			
(b)	Overhead	60% of sum of operating & maintenance costs		$331,128
(b)	Administrative Charges	2% of TCI		$266,680
(b)	Property Taxes	1% of TCI		$133,340
(b)	Insurance	1% of TCI		$133,340
	Total Indirect Annual Costs		*IAC*	*$864,488*
	Total Annual O&M Costs		*O&M*	*$1,546,676*
	Cost Effectiveness			
	Expected lifetime of equipment, years	10		
	Interest rate, %/yr	10.0%		
	Capital recovery factor	0.163		
	Total capital investment cost	$13,334,000		
	Annualized capital investment cost			*$2,170,047*
	Total Annualized Cost (including O&M)			*$3,716,723*
	Uncontrolled Emissions	114.9 tons SO_2/yr		*SO_2 Evaluation*
	Annual Cost/Ton Removed	28.7 tons SO_2/yr	25% SO2 removal (est.)	*$129,390*

Notes:

(a) Cost information obtained from Mr. Ed Schindler on December 18, 2006 via email.
(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.
(c) Cost information estimated by the Mill. Operating labor and maintenance costs were estimated using an assumption of two employees per shift, 3 shifts per day, and 90% utilization. Utility requirements were estimated using the same information for the semi-dry scrubber option. Percent removal efficiency was assumed to be the same as for the semi-dry scrubber option.

TABLE C-9
ESCANABA PAPER COMPANY
BART EVALUATION CAPITAL AND ANNUALIZED COSTS
NO. 8 BOILER SO_2 CONTROL
SEMI DRY SCRUBBER FOLLOWED BY A BAGHOUSE

CAPITAL COSTS

	COST ITEM	FACTOR	NO. 8 BOILER COST ($)
	Costs to Purchase and Install Equipment		
	Purchased Equipment Costs		
(a)	Lime preparation spray dryer, baghouse, & instrumentation		$1,115,000
(c)	New stack		$200,000
(c)	Platform materials to support the new equipment		$75,000
(c)	New fan to compensate for loss in pressure across boiler		$500,000
(c)	Baghouse ash handling system		$400,000
(c)	Lime reagent delivery and storage system		$150,000
(c)	Electrical		$300,000
	Purchased Equipment Costs Subtotal	*A*	*$2,740,000*
(b)	Instrumentation	0.100 A	included above
(b)	Sales taxes	0.030 A	$82,200
(b)	Freight	0.050 A	$137,000
	Total Purchased Equipment Cost	*B*	*$2,959,200*
	Direct Installation Costs		
(c)	Demolition of existing fan and stack, installation of new stack, platform, new fan, baghouse ash handling system, and lime reagent delivery and storage system	1.80 B	$5,326,560
(b)	Foundations and supports	0.12 B	$355,104
(b)	Handling & erection for lime preparation spray dryer, baghouse, & instrumentation	0.40 B	$1,183,680
(b)	Electrical	0.01 B	$29,592
(b)	Piping	0.30 B	$887,760
(b)	Insulation	0.01 B	$29,592
(b)	Painting	0.01 B	$29,592
	Direct Installation Cost	*C*	*$7,841,880*
	Total Direct Cost	*D*	*$10,801,080*
	Indirect Costs (Installation)		
(b)	Engineering	0.10 B	$295,920
(b)	Construction & field expenses	0.10 B	$295,920
(b)	Contractor fees	0.10 B	$295,920
(b)	Start-up	0.01 B	$29,592
(b)	Performance Test	0.01 B	$29,592
(b)	Contingencies	0.03 B	$88,776
	Total Indirect Cost		*$1,035,720*
	Total Capital Investment (TCI)		*$11,836,800*

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
	Annual Operating Costs			
	Direct Annual Costs			
	Operating Labor			
(c)	Labor, two employees	3 hours/shift	$56.00 per hour	$331,128
	Maintenance			
(c)	Maintenance Labor	2 hours/shift	$56.00 per hour	$110,376
(c)	Maintenance Materials	100% of maintenance labor		$110,376
	Utilities			
(a),(c)	Chemicals	36 lbs/hr	$88.52 per ton Lime	$12,562
(a),(c)	Fresh Water usage	26 gpm	$0.14 per 1000 gal	$1,663
(a),(c)	Waste disposal	90 lbs/hr	$18.00 per ton	$6,386
(a),(c)	Electricity	261 KWh	$0.05 per kWh	$109,697
	Total Direct Annual Costs		*DAC*	*$682,188*
	Indirect Annual Costs			
(b)	Overhead	60% of sum of operating & maintenance costs		$331,128
(b)	Administrative Charges	2% of TCI		$236,736
(b)	Property Taxes	1% of TCI		$118,368
(b)	Insurance	1% of TCI		$118,368
	Total Indirect Annual Costs		*IAC*	*$804,600*
	Total Annual O&M Costs		*O&M*	*$1,486,788*
	Cost Effectiveness			
	Expected lifetime of equipment, years	10		
	Interest rate, %/yr	10.0%		
	Capital recovery factor	0.163		
	Total capital investment cost	$11,836,800		
	Annualized capital investment cost			*$1,926,385*
	Total Annualized Cost (Including O&M)			*$3,413,172*
	Uncontrolled Emissions	114.9 tons SO_2/yr		***SO_2 Evaluation***
	Annual Cost/Ton Removed	28.7 tons SO_2/yr	25% SO_2 removal (guarantee from vendor)	*$118,822*

Notes:

(a) Cost information obtained from Turbosonic via email on November 28, 2006.
(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.
(c) Cost information estimated by the Mill. Direct installation costs were approximated using a combination of Mill historical information and experience with multiple capital equipment installations. This experience indicates that the total capital investment should equal four times the purchased capital equipment cost because of the complexity of the installation due to the demolition work and the new equipment installation that would need to occur at high elevations. Operating labor and maintenance costs were estimated using an assumption of two employees per shift, 3 shifts per day, and 90% utilization.

TABLE C-10
ESCANABA PAPER COMPANY
BART EVALUATION CAPITAL AND ANNUALIZED COSTS
NO. 9 BOILER NO_x CONTROL
SELECTIVE CATALYTIC REDUCTION (SCR) WITH AIR HEATER

CAPITAL COSTS

	COST ITEM	FACTOR	NO. 9 BOILER COST ($)
	Costs to Purchase and Install Equipment		
	Purchased Equipment Costs		
(a)	SCR system including urea storage and delivery system, catalyst, and air heater		$711,000
(c)	Platform materials to support the new equipment		$75,000
(c)	New fan		$303,030
(c)	New stack		$200,000
(c)	Electrical for the fan		$181,818
	Purchased Equipment Costs Subtotal	*A*	*$1,470,848*
(b)	Instrumentation	0.100 A	$147,085
(b)	Sales taxes	0.030 A	$44,125
(b)	Freight	0.050 A	$73,542
	Total Purchased Equipment Cost	*B*	*$1,735,601*
	Direct Installation Costs		
(c)	Installation of SCR system including air heater, urea storage and delivery system, platform, demolition of old stack, installation of new fan, new stack, foundations and supports, electrical, piping, insulation, and painting	1.85 B	$3,210,862
	Direct Installation Cost	C	*$3,210,862*
	Total Direct Cost	*D*	*$4,946,463*
	Indirect Costs (Installation)		
(b)	General Facilities	0.05 D	$247,323
(b)	Engineering and Home Office Fees	0.10 D	$494,646
(b)	Process Contingency	0.05 D	$247,323
(b)	Project Contingency	0.15 (D+Gen Fac+Eng+Proc Cont)	$890,363
(b)	Total Plant Cost	(D+Gen Fac+Eng+Proc Cont+Proj Cont)	$6,826,120
(b)	Preproduction Cost	0.02 Total Plant Cost	$136,522
	Total Capital Investment (TCI)..	(Tot Plt Cost+Pre Prod Cost)	*$6,962,642*

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
	Annual Operating Costs			
	Direct Annual Costs			
	Operating Labor			
(c)	Labor, one employee	0.5 hours/shift	$56.00 per hour	$27,594
	Maintenance			
(b)	Maintenance Labor and Materials	0.015 TCI		$104,440
	Utilities			
(a),(c)	Reagent	339012 gal/yr	$1.25 per gal	$423,765
(a),(c)	Natural gas for air heater system (350F to 600F)	22.3 MMBtu/hr	$8.05 per MMBtu	$1,415,296
(a),(c)	Electricity	0.1 KWh	$0.05 per kWh	$42
(a),(c)	Catalyst replacement	20 m^3	$321,000 per 12,000 hours	$210,897
(a),(c)	Spent catalyst disposal (assuming 1000 kg/m^3 density)	tons of 5 catalyst	$18.00 per ton per 12,000 hours	$54
	Total Direct Annual Costs		*DAC*	*$2,182,088*
	Indirect Annual Costs			
(b)	Overhead	60% of sum of operating & maintenance costs		$79,220
(b)	Administrative Charges	2% of TCI		$139,253
(b)	Property Taxes	1% of TCI		$69,626
(b)	Insurance	1% of TCI		$69,626
	Total Indirect Annual Costs		*IAC*	*$357,726*
	Total Annual O&M Costs		*O&M*	*$2,539,814*
	Cost Effectiveness			
	Expected lifetime of equipment, years	10		
	Interest rate, %/yr	10.0%		
	Capital recovery factor	0.163		
	Total capital investment cost	$6,962,642		
	Annualized capital investment cost			*$1,133,138*
	Total Annualized Cost (Including O&M)			*$3,672,952*
	Uncontrolled Emissions (Updated Estimate of Emissions)	296.6 tons NOx/yr		*NOx Evaluation*
	Annual Cost/Ton Removed	266.9 tons NOx/yr	90% NOx removal	*$13,761*

Notes:

(a) Cost information obtained from Mr. Ed Schindler at Combustion Components Associates (CCA) on December 16, 2006.
(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.
(c) Cost information estimated by the Mill. Direct installation costs were approximated using a combination of Mill historical information and experience with multiple capital equipment installations. This experience indicates that the total capital investment should equal four times the purchased capital equipment cost because of the complexity of the installation that would need to occur at high elevations. Operating labor and maintenance costs were estimated using an assumption of one employee per shift, 3 shifts per day, and 90% utilization.

TABLE C-11
ESCANABA PAPER COMPANY
BART EVALUATION CAPITAL AND ANNUALIZED COSTS
NO. 9 BOILER NO_x CONTROL
LOW NO_X NATURAL GAS BURNERS

CAPITAL COSTS

COST ITEM	FACTOR	NO. 9 BOILER COST ($)
Costs to Purchase and Install Equipment		
Purchased Equipment Costs		
(a) Burners		$198,290
Purchased Equipment Costs Subtotal	*A*	*$198,290*
(b) Instrumentation	0.100 A	$19,829
(b) Sales taxes	0.030 A	$5,949
(b) Freight	0.050 A	$9,915
Total Purchased Equipment Cost	*B*	*$233,982*
Direct Installation Costs		
(c) Guns, piping, electrical, refractory, misc.	1.84 B	$430,527
Direct Installation Cost	C	*$430,527*
Total Direct Cost	*D*	*$664,509*
Indirect Costs (Installation)		
(b) General Facilities	0.05 D	$33,225
(b) Engineering and Home Office Fees	0.10 D	$66,451
(b) Process Contingency	0.05 D	$33,225
(b) Project Contingency	0.15 (D+Gen Fac+Eng+Proc Cont)	$119,612
(b) Total Plant Cost	(D+Gen Fac+Eng+Proc Cont+Proj Cont)	$917,023
(b) Preproduction Cost	0.02 Total Plant Cost	$18,340
Total Capital Investment (TCI)............	Tot Plt Cost+Pre Prod Cost	*$935,363*

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ANNUALIZED COSTS

COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
Annual Operating Costs			
Direct Annual Costs			
Operating Labor			
(c) Labor, one employee	0.5 hours/shift	$56.00 per hour	$27,594
Maintenance			
(b) Maintenance Labor and Materials	0.015 TCI		$14,030
Utilities			
Total Direct Annual Costs		*DAC*	*$41,624*
Indirect Annual Costs			
(b) Overhead	60% of sum of operating & maintenance costs		$24,975
(b) Administrative Charges	2% of TCI		$18,707
(b) Property Taxes	1% of TCI		$9,354
(b) Insurance	1% of TCI		$9,354
Total Indirect Annual Costs		*IAC*	*$62,389*
Total Annual O&M Costs		*O&M*	*$104,014*
Cost Effectiveness			
Expected lifetime of equipment, years	10		
Interest rate, %/yr	10.0%		
Capital recovery factor	0.163		
Total capital investment cost	$935,363		
Annualized capital investment cost			*$152,226*
Total Annualized Cost (Including O&M)			*$256,240*
Cost Effectiveness			
Uncontrolled Emissions due to Gas Firing Only	33.9 tons NOx/yr (using 2005 operating data & AP-42 e.f.)		*NOx Evaluation*
Annual Cost/Ton Removed	13.6 tons NOx/yr	40% NOx removal	*$18,884*

Notes:

(a) Cost information obtained from Coen as part of the Mill's April, 2003 engineering study evaluated by Mr. Joe Peterson for the No. 8 Boiler. An assumption was made that the capital, installation, and operating costs for the two systems would be similar.
(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.
(c) Cost information estimated by the Mill. Direct installation costs were approximated using a combination of Mill historical information and experience with multiple capital equipment installations. This experience indicates that the total capital investment should equal four times the purchased capital equipment cost (for relatively complicated installations such as this). Operating labor and maintenance costs were estimated using an assumption of one employee per shift, 3 shifts per day, and 90% utilization.

TABLE C-12
ESCANABA PAPER COMPANY
BART EVALUATION CAPITAL AND ANNUALIZED COSTS
NO. 9 BOILER NO_x CONTROL
SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

CAPITAL COSTS

	COST ITEM	FACTOR	NO. 9 BOILER COST ($)
	Costs to Purchase and Install Equipment		
	Purchased Equipment Costs		
(a)	SNCR urea-based system including storage and delivery system		$750,000
(c)	Platform materials to support the new equipment		$75,000
(c)	Controls		$200,000
	Purchased Equipment Costs Subtotal	A	*$1,025,000*
(b)	Sales taxes	0.030 A	$30,750
(b)	Freight	0.050 A	$51,250
	Total Purchased Equipment Cost	B	*$1,107,000*
	Direct Installation Costs		
(c)	SNCR system including urea storage and delivery system, platform, electrical, piping, insulation, and painting	1.65 B	$1,826,550
	Direct Installation Cost	C	*$1,826,550*
	Total Direct Cost	D	*$2,933,550*
	Indirect Costs (Installation)		
(b)	General Facilities	0.05 D	$146,678
(b)	Engineering and Home Office Fees	0.10 D	$293,355
(b)	Process Contingency	0.05 D	$146,678
(b)	Project Contingency	0.15 (D+Gen Fac+Eng+Proc Cont)	$528,039
(b)	Total Plant Cost	(D+Gen Fac+Eng+Proc Cont)+Proj Cont)	$4,341,654
(b)	Preproduction Cost	0.02 Total Plant Cost	$86,833
	Total Capital Investment (TCI)**...**	(Tot Plant Cost+Pre Prod Cost)	*$4,428,487*

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ANNUALIZED COSTS

	COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
	Annual Operating Costs			
	Direct Annual Costs			
	Operating Labor			
(c)	Labor, one employee	0.5 hours/shift	$56.00 per hour	$27,594
	Maintenance			
(b)	Maintenance Labor and Materials	0.015 TCI		$66,427
	Utilities			
(c),(d)	Urea reagent	44,700 gal/yr	$1.25 per gal	$55,875
(c),(d)	Fresh Water usage	204,188 gal/yr	$0.14 per 1000 gal	$28
(c),(d)	Additional fuel requirement due to loss of (	0.2 MMBtu/hr	$4.80 per MMBtu	$8,252
(c),(d)	Electricity	5.9 KWh	$0.05 per kWh	$2,458
	Total Direct Annual Costs		***DAC***	*$160,635*
	Indirect Annual Costs			
(b)	Overhead	60% of sum of operating & maintenance costs		$56,413
(b)	Administrative Charges	2% of TCI		$88,570
(b)	Property Taxes	1% of TCI		$44,285
(b)	Insurance	1% of TCI		$44,285
	Total Indirect Annual Costs		***IAC***	*$233,552*
	Total Annual O&M Costs		***O&M***	*$394,187*
	Cost Effectiveness			
	Expected lifetime of equipment, years	10		
	Interest rate, %/yr	10.0%		
	Capital recovery factor	0.163		
	Total capital investment cost	$4,428,487		
	Annualized capital investment cost			*$720,716*
	Total Annualized Cost (Including O&M)			*$1,114,903*
	Uncontrolled Emissions (Updated Estimate of Emissions)	296.6 tons NOx/yr		***NOx Evaluation***
	Annual Cost/Ton Removed	103.8 tons NOx/yr	35% NOx removal (guarantee from vendor)	*$10,741*

Notes:

(a) Cost information obtained from Mr. Ed Schindler at CCA, Inc. via telephone conversation on December 6, 2006 for the SNCR equipment.
(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.
(c) Cost information estimated by the Mill. Direct installation costs were approximated using a combination of Mill historical information and experience with multiple capital equipment installations. This experience indicates that the total capital investment should equal four times the purchased capital equipment cost because of the complexity of the installation that would need to occur at high elevations. Operating labor and maintenance costs were estimated using an assumption of one employee per shift, 3 shifts per day, and 90% utilization.
(d) Usage information estimated based on other similar SNCR installations.

TABLE C-13
ESCANABA PAPER COMPANY
BART EVALUATION CAPITAL AND ANNUALIZED COSTS
NO. 9 POWER BOILER NO_X CONTROL
FLUE GAS RECIRCULATION

CAPITAL COSTS

COST ITEM	FACTOR	NO. 9 BOILER COST ($)
Costs to Purchase and Install Equipment		
Purchased Equipment Costs		
(a) Flue gas recirculation system		$600,000
(c) New fan		$500,000
(c) Motor and starter		$300,000
Purchased Equipment Costs Subtotal	*A*	*$1,400,000*
(b) Instrumentation	0.100 A	$140,000
(b) Sales taxes	0.030 A	$42,000
(b) Freight	0.050 A	$70,000
Total Purchased Equipment Cost	*B*	*$1,652,000*
Direct Installation Costs		
(c) Installation of flue gas recirculation system, new fan, and electrical	1.65 B	$2,725,800
Direct Installation Cost	*C*	*$2,725,800*
Total Direct Cost	*D*	*$4,377,800*
Indirect Costs (Installation)		
(b) Engineering	0.10 B	$165,200
(b) Construction & field expenses	0.10 B	$165,200
(b) Contractor fees	0.10 B	$165,200
(b) Start-up	0.01 B	$16,520
(b) Performance Test	0.01 B	$16,520
(b) Contingencies	0.03 B	$49,560
Total Indirect Cost		*$578,200*
Total Capital Investment (TCI)		*$4,956,000*

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ANNUALIZED COSTS

COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
Annual Operating Costs			
Direct Annual Costs			
Operating Labor			
(c) Labor, one employee	0.5 hours/shift	$56.00 per hour	$27,594
Maintenance			
(c) Maintenance Labor	0.5 hours/shift	$56.00 per hour	$27,594
(c) Maintenance Materials	100% of maintenance labor		$27,594
Utilities			
(c) Electricity	assume negligible	$0.05 per kWh	
Total Direct Annual Costs		*DAC*	*$82,782*
Indirect Annual Costs			
(b) Overhead	60% of sum of operating & maintenance costs		$49,669
(b) Administrative Charges	2% of TCI		$99,120
(b) Property Taxes	1% of TCI		$49,560
(b) Insurance	1% of TCI		$49,560
Total Indirect Annual Costs		*IAC*	*$247,909*
Total Annual O&M Costs		*O&M*	*$330,691*
Cost Effectiveness			
Expected lifetime of equipmer	10		
Interest rate, %/yr	10.0%		
Capital recovery factor	0.163		
Total capital investment cost	$4,956,000		
Annualized capital investment cost			*$806,566*
Total Annualized Cost (Including O&M)			*$1,137,257*
Uncontrolled Emissions (Updated Estimate of Emissions)	296.6 tons NOx/yr		***NOx Evaluation***
Annual Cost/Ton Removed	59.3 tons NOx/yr	20% NOx removal (est. from Jansen)	*$19,173*

Notes:

(a) Rough estimate cost information obtained from Mr. Arie Verloop at Jansen Boiler Co. via telephone conversation on December 16, 2006 for the FGR equipment.
(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.
(c) Cost information estimated by the Mill. Direct installation costs were approximated using a combination of Mill historical information and experience with multiple capital equipment installations. This experience indicates that the total capital investment should equal three times the purchased capital equipment cost for relatively simple installations such as this. Operating labor and maintenance costs were estimated using an assumption of one employee per shift, 3 shifts per day, and 90% utilization.

TABLE C-14
ESCANABA PAPER COMPANY
BART EVALUATION ANNUAL COSTS
NO. 9 POWER BOILER SO_2 CONTROL
PUTTING CAUSTIC ON THE SCRUBBERS

CAPITAL COSTS

COST ITEM	FACTOR	NO. 9 BOILER COST ($)
Costs to Purchase and Install Equipment		
Purchased Equipment Costs		
Storage Tank		$150,000
Piping		$100,000
Electrical		$100,000
Controls		$100,000
Contingency		$50,000
Purchased Equipment Costs Subtotal	*A*	***$500,000***
(a) Sales taxes	0.030 A	$15,000
(a) Freight	0.050 A	$25,000
Total Purchased Equipment Cost	*B*	***$540,000***
Direct Installation Costs		
Installation costs for storage tank, piping, insulation, electrical, and instrumentation	1.65 B	$891,000
Direct Installation Cost	*C*	***$891,000***
Total Direct Cost	*D*	***$1,431,000***
Indirect Costs (Installation)		
(a) Engineering	0.10 B	$54,000
(a) Construction & field expenses	0.10 B	$54,000
(a) Contractor fees	0.10 B	$54,000
(a) Start-up	0.01 B	$5,400
(a) Performance Test	0.01 B	$5,400
(a) Contingencies	0.03 B	$16,200
Total Indirect Cost		***$189,000***
Total Capital Investment (TCI)..		***$1,620,000***

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ANNUALIZED COSTS

COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
Annual Operating Costs			
Direct Annual Costs			
Operating Labor			
Labor, one employee	0.5 hour/shift	$56.00 per hour	$27,594
Maintenance			
Maintenance Labor	0.5 hour/shift	$56.00 per hour	$27,594
Maintenance Materials	100% of maintenance labor		$27,594
Utilities			
Caustic (1 lb NaOH to remove 1 lb SO2)	21.6 tons NaOH/yr	$420.60 per ton NaOH	$9,064
Total Direct Annual Costs		***DAC***	***$91,846***
Indirect Annual Costs			
(a) Overhead	60% of sum of operating & maintenance costs		$49,669
(a) Administrative Charges	2% of TCI		$32,400
(a) Property Taxes	1% of TCI		$16,200
(a) Insurance	1% of TCI		$16,200
Total Indirect Annual Costs		***IAC***	***$114,469***
Total Annual O&M Costs		***O&M***	***$206,315***
Cost Effectiveness			
Expected lifetime of equipment, years	10		
Interest rate, %/yr	10.0%		
Capital recovery factor	0.163		
Total capital investment cost	$1,620,000		
Annualized capital investment cost			***$263,648***
Total Annualized Cost (Including O&M)			***$469,963***
Uncontrolled Emissions	43.1 tons SO_2/yr		***SO_2 Evaluation***
Annual Cost/Ton Removed	21.6 tons SO_2/yr	50% SO_2 removal (est.)	***$21,808***

Notes:

(a) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

All other costs were estimated by the Mill. Operating labor and maintenance costs were estimated using an assumption of one employee per shift, 3 shifts per day, and 90% utilization.

Direct installation costs were approximated using a combination of Mill historical information and experience with multiple capital equipment installations. This experience indicates that the total capital investment should equal three times the purchased capital equipment cost (for relatively simple installations such as this).

TABLE C-15
ESCANABA PAPER COMPANY
BART EVALUATION ANNUAL COSTS
RECOVERY FURNACE SO_2 CONTROL
SWITCHING TO BURN ONLY LOW SULFUR NO. 2 FUEL OIL

No. 6 Fuel Oil related SO_2 emissions	44.6	2004 TPY
No. 6 Fuel Oil usage	1,071,764	2004 gal
No. 6 Fuel Oil heat value	159,829	2004 Btu/gal
No. 2 Fuel Oil Sulfur Content	0.05%	2005 %S
No. 2 Fuel Oil heat value	140,000	Assumed Btu/gal
SO_2 emission factor (gas)	0.6	lb/MMft3 (AP-42)
SO_2 emission factor (No. 2 fuel oil)	7.85	lb/M gal (AP-42), 157*%S
Heat value from fuel oil	171,299	MMBtu/yr
SO_2 from No. 2 Fuel Oil	4.2	2005 TPY from No. 2 instead of No. 6 Fuel Oil
Cost of No. 6 Fuel Oil	$6.64	per MMBtu (2006 pricing)
Cost of No. 2 Fuel Oil	$2.30	Per gallon (http://tonto.eia.doe.gov/dnav/pet/pet_pri_dist_dcu_nus_m.htm)
Theoretical SO_2 removed by switching from No. 6 to No. 2 Fuel Oil	40.4	TPY
Cost to fire No. 6 Fuel Oil	$1,171,685	per year
Cost to fire No. 2 Fuel Oil	$2,814,197	per year
Cost difference between No. 6 and No. 2 Fuel Oil	$1,642,512	per year
Annualized $ to install a dedicated No. 2 Fuel Oil system (see below)	$277,789	per year
Total incremental $ per year to switch from No. 6 to No. 2 Fuel Oil	$1,920,302	per year
Cost per ton of SO_2 removal	$47,540	Incremental $ per ton of SO_2 removed

CAPITAL COSTS

	COST ITEM	FACTOR	NO. 2 FUEL OIL SYSTEM COST ($)
	Costs to Purchase and Install Equipment		
	Purchased Equipment Costs		
	No. 2 Fuel Oil storage tank		$150,000
	Piping		$60,000
	Electrical/Pumps		$15,000
	Purchased Equipment Costs Subtotal	A	*$225,000*
(a)	Instrumentation	0.100 A	$22,500
(a)	Sales taxes	0.030 A	$6,750
(a)	Freight	0.050 A	$11,250
	Total Purchased Equipment Cost	B	*$243,000*
	Direct Installation Costs		
	Installation of purchased equipment	1.6 B	$388,800
	Direct Installation Cost	C	*$388,800*
	Total Direct Cost	D	*$631,800*
	Indirect Costs (Installation)		
(a)	Engineering	0.10 B	$24,300
(a)	Construction & field expenses	0.10 B	$24,300
(a)	Contractor fees	0.10 B	$24,300
(a)	Start-up	0.01 B	$2,430
(a)	Performance Test	0.01 B	$2,430
(a)	Contingencies	0.03 B	$7,290
	Total Indirect Cost		*$85,050*
	Total Capital Investment (TCI)		*$716,850*

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	UNIT COST	ANNUAL COST ($)
	Annual Operating Costs			
	Direct Annual Costs			
	Operating Labor			
	Labor, one employee	0.5 hours/shift	$56.00 per hour	$27,594
	Maintenance			
	Maintenance Labor	0.5 hours/shift	$56.00 per hour	$27,594
	Maintenance Materials	100% of maintenance labor		$27,594
	Utilities			
	Electricity	assume negligible	$0.05 per kWh	
	Total Direct Annual Costs		DAC	*$82,782*
	Indirect Annual Costs			
(a)	Overhead	60% of sum of operating & maintenance costs		$49,669
(a)	Administrative Charges	2% of TCI		$14,337
(a)	Property Taxes	1% of TCI		$7,169
(a)	Insurance	1% of TCI		$7,169
	Total Indirect Annual Costs		IAC	*$78,343*
	Total Annual O&M Costs		O&M	*$161,125*
	Cost Effectiveness			
	Expected lifetime of equipment, years	10		
	Interest rate, %/yr	10.0%		
	Capital recovery factor	0.163		
	Total capital investment cost	$716,850		
	Annualized capital investment cost			*$116,664*
	Total Annualized Cost (Including O&M)			*$277,789*

Notes:

(a) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS. The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

All other costs were estimated by the Mill. Operating labor and maintenance costs were estimated using an assumption of one employee per shift, 3 shifts per day, and 90% utilization.

Direct installation costs were approximated using a combination of Mill historical information and experience with multiple capital equipment installations. This experience indicates that the total capital investment should equal three times the purchased capital equipment cost (for relatively simple installations such as this).

Appendix 9L

New Page- Paper Company BART Letter

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February 2, 2010

Mr. Bob Irvine
Michigan Department of Natural Resources and Environment
525 West Allegan Street
P.O. Box 30260
Lansing, Michigan 48909-0260

Re: Escanaba Paper Company (EPC) Best Available Retrofit Technology (BART) Response

Dear Mr. Irvine:

NewPage Corporation Escanaba Paper Company (EPC) has prepared the following response to address outstanding issues related to the Best Available Retrofit Technology (BART) analyses. EPC has prepared this response to reaffirm the conclusions of the original BART analysis and to reiterate that EPC believes that the original BART analysis is consistent with the intent of the BART guidance contained in 40 CFR Part 51 Appendix Y as well as the current U.S. EPA interpretation of BART requirements.

Background

There are five (5) emission units at the EPC mill that have start-up dates between August 7, 1962 and August 7, 1977. EPC conducted a visibility modeling analysis using 24-hour worst-case actual emissions for each VIP for the BART-eligible source (i.e., each of the five emission units) at the mill. The results of the baseline visibility modeling indicated the BART-eligible source could contribute to visibility impairment under worst-case meteorological conditions and when all of the BART-eligible sources at the mill were emitting at their maximum 24-hour actual emission rates. Therefore the emission units (i.e. the BART-eligible source) are *subject to BART*. EPC then conducted a case-by-case five-step BART analysis for each emission unit comprising the BART-eligible source. The conclusions of the five-step BART analysis were provided to Michigan DEQ in a January 2007 report. Supplemental information has been submitted to Michigan DEQ to clarify and expand on the original BART report. The most recent information related directly to the BART report was submitted to Michigan DEQ in May 2008 and reflected the use of the 20% best days background data and the use of U.S. EPA's refined Interagency Monitoring of Protected Visual Environments (IMPROVE) equation.

EPC's BART Analysis

The BART report that EPC prepared and submitted to Michigan DEQ in January 2007 outlined the potential control options for each of the five (5) emission units at the EPC mill. Using vendor quotes for control equipment and U.S. EPA's 2003 Air Pollution Control Cost Manual, EPC provided costs for installing and operating the control options where it was technically feasible to install control equipment. The control costs for all emission units were generally greater than $10,000 per ton of VIP removed except for the No. 8 Power Boiler where select control costs for sulfur dioxide (SO_2) and oxides of

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nitrogen (NO_X) were approximately $4,000 per ton of VIP removed. EPC believes that the SO_2 and NO_X control costs for the No. 8 Power Boiler are at the high range of cost effectiveness. However, the consideration of a control cost by itself is an incomplete review under the Five Step case-by-case BART analysis. The five step evaluation of visibility impacts must be included in the case-by-case BART analysis.

The visibility modeling performed by EPC included pre-control and post control visibility impacts for each of the five emission units where control options were technically feasible. The visibility modeling demonstrated that the application of a control technology did not result in a meaningful improvement in visibility. For example, the addition of low NO_X burners on the No. 8 Power Boiler would result in 0.12 deciview change in the 98th percentile visibility value. It is important to note that the procedures identified in 40 CFR Part 51 Appendix Y state the evaluation of visibility modeling is just a portion of the overall BART process and that even if modeled visibility impacts above 0.5 deciviews are predicted, the visibility impacts can be judged on a relative basis not an absolute basis. This means that 98th percentile results above 0.5 deciview can be judged to be acceptable.

Considering all of the factors in the five step case-by-case BART analysis, EPC believes there is no best available retrofit technology that would apply to any of the five (5) emission units at the mill. Therefore, since there is no BART, there are no control requirements and no enforceable emission limits that need to be established. As described in 40 CFR Part 51 Appendix Y enforceable emission limits are necessary <u>when</u> there are <u>BART requirements</u> (i.e., emission controls).

If Michigan DNRE has questions concerning this letter or the information that was presented in the January 2007 BART report, please do not hesitate to contact me at 906-233-2929.

Sincerely

Todd Schmidt
Environmental Manager

Appendix 9M

Emission Limits – Excerpts from ROP for New Page Paper Company

EU #8 Boiler System
EMISSION UNIT CONDITIONS

DESCRIPTION: The #8 Boiler (EG8B13) is a Combustion Engineering boiler rated for 450,000 pounds of steam per hour (approximately 594 million BTU per hour heat input) that provides steam for mill processes and steam turbine-generator sets for producing electricity. A Flu Gas Recirculation system was installed on the # 8 Boiler. The #8 Boiler burns natural gas and fuel oil

POLLUTION CONTROL EQUIPMENT NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Underlying Applicable Requirements
1. NOx	The Permittee shall comply with the appropriate NOx emission limitations averaged over the ozone control season. a. The emission limitation when firing gas is 0.20 lbs/MMBtu. b. The emission limitation when firing residual oil is 0.40 lbs/MMBtu. The ozone control period is May 1 through September 30.	**(R336.1801)**[1] **(R336.1801(13)**[1] **(R336.1801(13)**[1] **(R336.1801(1)(f))**[1]

II. MATERIAL LIMIT(S)

Material	Limit	Underlying Applicable Requirements
1. Fuel Oil	The fuel oil burned in #8 Boiler shall not exceed a maximum sulfur content of 1.0 percent by weight, calculated on the basis of 18,000 BTU per pound.	**(R336.1201, R336.1401)**

III. PROCESS/OPERATIONAL RESTRICTION(S) : NA

IV. DESIGN/EQUIPMENT PARAMETER(S): NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall measure NOx emissions using a NOX CEMS during the ozone control period in accordance with the provisions of R336.1801(11). **(R336.1801(8))**[1]

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall obtain and keep records of the sulfur and BTU content of the fuel oil burned in #8 Boiler. For each shipment received, the permittee shall obtain from the supplier a laboratory analysis of the fuel oil sulfur and BTU content. The permittee shall also record the date received, fuel oil grade, source of fuel oil and

EU #9 Boiler System
EMISSION UNIT CONDITIONS

DESCRIPTION: The # 9 Boiler (EU9B03) is a Babcock & Wilcox boiler rated for 250,000 pounds of steam per hour (approximately 360 million BTU per hour heat input) that provides steam for mill processes and steam turbine-generators for producing electricity. The # 9 boiler burns primarily wood residue, but may also burn natural gas, and paper cores. The boiler system has two emission units, the #9 Boiler and Wood Residue Surge Bin.

POLLUTION CONTROL EQUIPMENT: Multiclone and two wet scrubbers on the # 9 boiler exhaust; Cyclone dust collector on Wood Residue Surge Bin.

Flexible Grouping ID: FGRMPMOD

I. EMISSION LIMIT(S)

Pollutant	Limit	Underlying Applicable Requirements
1. NOx	The permittee shall comply with applicable oxides of nitrogen emission limits for the # 9 boiler, as specified in Table 81 of Rule 801, during years when the boiler meets the definition of a fossil fuel fired emission unit per the definition in R336.1801(1)(b).	**(R336.1801)**[1]
2. Particulate	If the wood residue heat input to # 9 boiler is greater than 75 percent of the total heat input to the boiler, the particulate emission from# 9 boiler shall not exceed 0.50 pounds per 1000 pounds of exhaust gases, measured at operating conditions, corrected to 50 percent excess air.	**(R336.1201, R336.1331)**
3. Particulate	If the wood residue heat input to the # 9 boiler is less than or equal to 75 percent of the total heat input to the boiler, the particulate emission from # 9 boiler shall not exceed the fraction of total heat input from the wood residue times 0.67 pounds per 1000 pounds of exhaust gases, measured at operating conditions, corrected to 50 percent excess air.	**(R336.1201, R336.1331)**
4. Particulate	The particulate emission from the cyclone dust collector serving the wood residue surge bin shall not exceed 0.10 pounds per 1000 pounds of exhaust gases, measured at operating conditions.	**(R336.1331)**

II. MATERIAL LIMIT(S): NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EU9B03 while burning wood residue and/or paper cores unless the multiclone dust collector and two wet scrubbers are operating properly. **(R336.1201, R336.1910)**

2. The permittee shall immediately cease wood residue input feed to EU9B03, consistent with safe operating procedures, upon initiation of scrubber bypass. During a scrubber bypass, the permittee shall burn only natural gas in EU9B03. Wood residue fuel input shall not be restarted until the scrubber is back on line and functioning properly. **(R336.1201, R336.1331, R336.1910)**

EU Chemical Recovery Furnace System
EMISSION UNIT CONDITIONS

DESCRIPTION: The **Chemical Recovery Furnace System** is used to regenerate chemicals used in the kraft process. The #10 Recovery Furnace is rated for 565,000 pounds of steam per hour (approximately 950 million BTU per hour heat input), and burns black liquor, natural gas, #6 fuel oil, and used oil. Also, the #10 Recovery Furnace receives and incinerates HVLC noncondensible gases from the Digester System, Brownstock System, Evaporator System, and Chemical Recovery Furnace System. The Chemical Recovery Furnace System has one emitting units: #10 Recovery Furnace (EURF15).

POLLUTION CONTROL EQUIPMENT: Electrostatic precipitator on #10 Recovery Furnace.

I. EMISSION LIMIT(S)

Pollutant	Limit	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Arsenic	The arsenic emission from EURF15 while burning used oil and/or # 6 fuel oil shall not exceed 0.004 milligrams per cubic meter, corrected to 70 degrees Fahrenheit and 29.92 inches Hg.		**(R336.1901)**[1]
2. Cadmium	The cadmium emission from EURF15 while burning used oil and/or #6 fuel oil shall not exceed 0.038 milligrams per cubic meter, corrected to 70 degrees Fahrenheit and 29.92 inches Hg.		**(R336.1901)**[1]
3. Carbon Monoxide	The carbon monoxide emission from EURF15 shall not exceed 2000 parts per million by volume nor 1424 pounds per hour, based upon a one-hour average.		**(R336.1201, 40 CFR 52.21)**
4. Carbon Monoxide	The carbon monoxide emission from EURF15 shall not exceed 800 parts per million by volume nor 570 pounds per hour, based upon an eight-hour average.		**(R336.1201, 40 CFR 52.21)**
5.Chromium	The chromium emission from EURF15 while burning used oil and/or #6 fuel oil shall not exceed 0.016 milligrams per cubic meter, corrected to 70 degrees Fahrenheit and 29.92 inches Hg.		**(R336.1901)**[1]

Pollutant	Limit	Monitoring/ Testing Method	Underlying Applicable Requirements
6. HAP Metals measured as Particulate Matter (PM)	The permittee shall comply with the emission limits specified in one of the following options as provided in 40 CFR 63 Subpart MM: a. The Particulate Matter (PM) concentration in the # 10 Recovery Furnace exhaust gases shall not exceed 0.044 grain per dry standard cubic foot corrected to 8 percent oxygen; OR b. Alternative Particulate Matter (PM) emission limits established for each existing recovery furnace, smelt dissolving tank, and lime kiln that operates 6,300 hours per year or more as provided under 40 CFR 63.862(a)(1)(ii), subject to the limitations specified.		**(40 CFR 63.861)** **(40 CFR 63.862 (a)(1)(i)(A), 40 CFR 63.865(b))** **(40 CFR 63.862 (a)(1)(ii), 40 CFR 63.865(a), 40 CFR 63.865 (b))**
7. Nitrogen Oxides	The nitrogen oxides emission from EURF15 shall not exceed 400 parts per million by volume, nor 468 pounds per hour.		**(R336.1201, 40 CFR 52.21)**
8. Particulate	The particulate emission from EURF15 shall not exceed 0.033grains per dry standard cubic foot corrected to 8 percent oxygen, nor 60.5 pounds per hour. The permittee may petition the Department for an alternate particulate limit up to, but not exceeding, 0.044 grains per dry standard cubic foot of exhaust gases corrected to 8 percent oxygen. Such alternate particulate emission limit shall not be established by the Department unless the Department is reasonably convinced of all the following: a. All reasonable measures to reduce particulate emissions have been implemented or will be implemented in accordance with a schedule approved by the Department. b. Compliance with the original particulate emission limit is either technically or economically unreasonable. c. The requested alternate particulate limit is the limit that reflects the level of emission that can be reasonably achieved on a consistent basis.		**(R336.1201, R336.1331, 40 CFR 52.21)**
9. Polychlorinated Biphenyls	The polychlorinated biphenyls emission from EURF15 while burning used oil and/or #6 fuel oil shall not exceed 0.014 milligrams per cubic meter, corrected to 70 degrees Fahrenheit and 29.92 inches Hg.		**(R336.1901)**[1]
10. Sulfur Dioxide	The sulfur dioxide emission from EURF15 shall not exceed 250 parts per million by volume, nor 407 pounds per hour.		**R336.1201, 40 CFR 52.21)**
11. Total Reduced Sulfur	The total reduced sulfur emission from EURF15 shall not exceed 5 parts per million based upon a 12-hour average, corrected to 8 percent oxygen, nor 5.6 pounds per hour.		**(R336.1201, 40 CFR 52.21, 40 CFR 60.283)**

EU Smelt Dissolving Tank System
EMISSION UNIT CONDITIONS

DESCRIPTION: The Smelt Dissolving Tank System is used to regenerate chemicals used in the kraft process. The Smelt Dissolving Tank receives smelt from the # 10 Recovery Furnace, which it mixes with weak wash to generate green liquor that is transported to the Recausticizing System. The Smelt Dissolving Tank System has one emitting unit: The Smelt Dissolving Tank (EUST15).

POLLUTION CONTROL EQUIPMENT: Wet scrubber and mist eliminator on Smelt Dissolving Tank.

I. EMISSION LIMIT(S)

Pollutant	Limit	Monitoring/ Testing Method	Underlying Applicable Requirements
1.Particulate	a. The Particulate Matter (PM) concentration in the Smelt Dissolving Tank exhaust gases shall not exceed 0.20 pounds per ton of black liquor solids fired. b. Alternate Particulate Matter (PM) emission limits may be established for each existing smelt dissolving tank that operates 6,300 hours per year or more as provided under 40 CFR 63.862(a)(1)(ii), subject to limitations specified. c. The Particulate emission from the Smelt Dissolving Tank shall not exceed 0.15 lbs/1000 lbs of exhaust gases, calculated on a dry gas basis.		**a. (40 CFR 63.862(a)(i)(B), 40 CFR 63.865(b))** **b. (40 CFR 63.862(a)(1)(ii), 40 CFR 63.865(a), 40 CFR 63.865(b)** **c. (R336.1201, R336.1331, 40 CFR 52.21)**
2. Total Reduced Sulfur (TRS)	The total reduced sulfur emission from the Smelt Dissolving Tank shall not exceed 0.0084 grams per kilogram of black liquor solids based upon a 12 hour average.		**(R336.1201, 40 CFR 52.21)**

II. MATERIAL LIMIT(S): NA

III. PROCESS/OPERATIONAL RESTRICTION(S): NA

IV. DESIGN/EQUIPMENT PARAMETER(S): NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall test for particulate and total reduced sulfur emissions from the Smelt Dissolving Tank once every three years from the date of issuance of this permit. Test results shall be submitted in an acceptable manner with in 60 days of completion of the test. **(R336.1201, R336.1213(3))**

2. Performance tests shall be conducted according to procedures and test methods specified or approved by the Air Quality Division. Not less than 30 days prior to testing, a test plan shall be submitted to the AQD for review and approval. **(R336.2001, R336.2003)**

See Appendix 5

EU Lime Kiln System
EMISSION UNIT CONDITIONS

DESCRIPTION: The Lime Kiln System (EULK29) includes the Lime Kiln and two Lime Storage Bins, one for hot lime storage, one for purchased lime storage. The Lime Kiln is fired with natural gas and/or fuel oil. Also, the Lime Kiln is a backup incineration device for the Thermal Oxidizer System

POLLUTION CONTROL EQUIPMENT: Venturi scrubber and mist eliminator on EULK29. A common baghouse dust collector serves the two Lime Storage Bins.

I. EMISSION LIMIT(S)

Pollutant	Limit	Monitoring/ Testing Method	Underlying Applicable Requirements
1. HAP Metals measured as Particulate Matter (PM)	Pursuant to 40 CFR 63 Subpart MM, the permittee shall comply with the emission limits specified in one of the following options: a. The Particulate Matter (PM) concentration for EULK29 exhaust gases shall not exceed (0.064 grains per dry standard cubic foot) corrected to 10 percent oxygen based on a 3 hour averaging time at all times except during a SSM and as specified in 40 CFR 63.443(e), 40 CFR 36.446(g) and 40 CFR 63.864(k)(2). or b. Alternative Particulate Matter (PM) emission limits established for each existing recovery furnace, EUST15, and EULK29 that operates 6,300 hours per year or more as provided under 40 CFR 63.862(a)(1)(ii), subject to the limitations specified.		**(40 CFR 63.861)** **(40 CFR 63.6(f), 63.862(a)(1)(i)(c))** **(40 CFR 63.862(a)(1)(ii), 40 CFR 63.865(a), 40 CFR 63.865(b))**
2. Particulate	The particulate emission from EULK29 shall not exceed 0.20 pounds per 1000 pounds of exhaust gases measured at operating conditions.		**(R336.1201, R336.1331)**
3. Particulate	The particulate emission from the two Lime Storage Bins shall not exceed 0.10 pounds per 1000 pounds of exhaust gas, measured at operating conditions.		**(R336.1331)**
4. Sulfur Dioxide	The sulfur dioxide emission from EULK29 shall not exceed 9 pounds per hour.		**(R336.1201)**
5. Total Reduced Sulfur	The TRS concentration from EULK29 exhaust gases shall not exceed 20 parts per million by volume, based on a twelve hour average, corrected to 10 percent oxygen.		**(R336.1201)**

Appendix 9N

Smurfit-Stone Container Company BART Technical Analysis

Section	Page

Appendices

1.0 Introduction to The Regional Haze Rule

On July 1, 1999, the Environmental Protection Agency (EPA) finalized a rules package known as the "Regional Haze Regulations. The purpose of the regulation is to limit visibility-impairing emissions of particulate matter, sulfur and nitrogen compounds that impact federal Class I areas. These Class I areas include national parks, wilderness areas, and select areas of the country for which scenic views are considered an important attribute. As required by Section 169B of the Clean Air Act, the Regional Haze Regulations include Best Available Retrofit Technology (BART) provisions for certain sources that may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area. More specifically, BART applied to sources within 26 specific source categories that were constructed between 1962 and 1977 and that have the potential to emit 250 tons per year of visibility impairing pollutants. The rule requires states to submit implementation plans for visibility improvement to EPA no later than December 31, 2007. The state must revise the implementation plan and submit the revision by July 31, 2018 and every ten years thereafter.

On July 6, 2005, EPA issued another final rule, titled "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology." This rule lays out the procedural requirements for determination of Best Available Retrofit Technology (BART) for control of visibility-impairing pollutants for sources that may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area. The EPA defines BART as follows:

> *"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 a BART-eligible source. 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, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."*
>
> *The BART analysis identifies the best system of continuous emission reduction taking into account:*
>
> 1. *The available retrofit control options*
> 2. *Any pollution control equipment in use at the source (which affects the availability of options and their impacts).*
> 3. *The costs of compliance with control options*

4. *The remaining useful life of the facility*
5. *The energy and non-air quality environmental impacts of control options*
6. *The visibility impacts analysis*

Only one source at the Smurfit-Stone facility in Ontonagon, Michigan, the Riley Boiler #1, meets the BART eligibility requirements. This report documents the BART applicability determination process for that boiler. The report includes a review of the state/regional planning organization efforts at determining BART eligibility, updating the baseline conditions to 2005-2006 emission averages so as to reflect emission reductions already implemented at the source. Based on the information presented in the following sections, Smurfit Stone does not believe that BART requirements apply to the Ontonagon facility.

2.0 Existing Equipment

2.1 Riley Boiler

The Riley Boiler #1, installed in 1966, was designed to burn pulverized coal, wood waste, natural gas, and oil. When the mill installed emission control equipment for the Pulp and Paper MACT, the boiler was modified to also burn non-condensable gases (NCG). Wood waste is no longer fired and natural gas and oil are seldom fired.

Rated heat input is 375 MMBtu/hr. Flue gas emissions are controlled with multiclones and a Belco electrostatic precipitator which was installed in 1983. The design flue gas flow at the boiler outlet is 160,000 ACFM at a temperature of 475ºF.

2.2 Electrostatic Precipitator

A weighted-wire electrostatic precipitator (ESP) has been in place at the facility since 1983. The ESP removes particulates in the flue gas via electric forces. The particulates are given an electrical charge as they pass through the ESP and an electrical field forces the particulates to the collector plates. The collector plates are rapped to remove particulates from the collector which are then collected in a hopper at the bottom of the ESP. The ESP was designed for a gas flow rate of 160,000 ACFM at a temperature of 475ºF. Recent stack test reports have shown the ESP to be in excellent working condition with particulate removal efficiencies exceeding 99.9%.

2.3 Low NOx Burners

Riley Boiler #1 was retrofitted in 1995 with four low-NOx burners designed to burn pulverized coal. Low-NOx burners (LNBs) are designed to "stage" combustion. In this technology, a fuel-rich combustion zone is created by forcing additional air to the outside of the firing zone and by delaying the combustion of coal.

The burners are DB Riley model 3A Controlled Combustion Venturi (CCV). The design of these burners incorporates a venturi coal nozzle and spreader to reduce NOx emissions. The venturi nozzle concentrates the pulverized coal and primary air into a fuel-rich mixture. The fuel/air mixture passes over spreader blades that divide the mixture into distinct streams. Devolatilization of the coal in the fuel-rich mixture occurs at the burner exit in an oxygen-lean primary combustion zone, resulting in lower fuel NOx conversion. The streams enter the furnace in a helical pattern, resulting in gradual mixing of the coal and secondary air. Secondary air is introduced outside the primary combustion zone to further burn the fuel. Peak flame temperature is thus reduced and thermal NOx formation is suppressed.

Following installation of the LNBs, the NOx emission from Boiler #1 was approximately 0.75 lbs/MMBtu (2004).

2.4 Flame Stabilization Rings

To improve combustion and lower the NOx emissions after installation of the LNBs, flame stabilizer rings were installed during the fall of 2004. The most recent stack test resulted in a NOx emission rate of 0.403 pounds NOx per MMBtu.

2.5 Boiler MACT Compliance

SSCC has been required to address emissions of mercury and hydrogen chloride from the Riley Boiler under the NESHAP for Industrial/Commercial/Institutional Boilers and Process Heaters, commonly referred to as the Boiler MACT. To meet these requirements SSCC has begun installation of a multi-pollutant control system from Mobotec USA.

Mobotec System

The design and construction of a pollution control system from MobotecUSA is currently underway in an effort to ensure compliance with Boiler MACT. The Mobotec system was chosen to meet Boiler MACT requirements in large part due to their system's inherent reduction in NOx and because the system provides the potential for incorporating pollutant control upgrades for other pollutants.

The Mobotec control package is based on a Rotating Opposed Fired Air (ROFA) fan system. The ROFA fan system will supply high velocity air to multiple ROFA boxes installed at key locations inside the furnace of the boiler. This allows the boiler to achieve higher combustion efficiencies and lower pollutant emissions. The design and locations of the ROFA boxes are determined through computational fluid dynamics (CFD).

Below is Mobotec's description of their ROFA system taken from their website:

> *The volume of the furnace is set in rotation via special asymmetrically placed air nozzles. The combustion gases mix well with the added air, making a combustion gas swirl. This generates turbulence and rotation in the entire furnace. Rotation prevents laminated flow and the whole volume of the furnace can be used more effectively for the combustion process. The ROFA® swirl reduces the maximum temperature of the flames and increases heat absorption, which in turn improves the boilers overall efficiency. With the ROFA® technique surplus air can be reduced without increasing CO or other unwanted substances. The combustion*

air is mixed more effectively. The result is less cooling of the furnace due to unused combustion air, thereby increasing efficiency.

Some of the documented advantages of the ROFA techniques are:

- *Less temperature variation in the cross section of the furnace.*
- *A more even distribution of combustion products in the cross-section of the furnace (e.g., CO, NOx, SOx etc.)*
- *Rotary mixing dramatically reduces fly ash (i.e. unburnt content in the flue gas).*
- *Lower CO levels mean less surplus air. Less surplus air (O2) means less NOx and higher overall efficiency.*
- *Increased heat absorption from the furnace itself results in lower outgoing furnace temperature and potential increased energy output.*
- *Less temperature variation of superheated steam.*

To meet Boiler MACT requirements, Smurfit Stone is installing the ROFA system and a sorbent injection system (MinPlus) for control of mercury emissions. Smurfit-Stone expects that this system will also provide further NOx reductions from the Riley Boiler.

3.0 BART Applicability Determination

The regional haze rules established a multi-step process for determining which existing sources must apply BART.

3.1 BART 'Eligible' Sources

In the first step of the process, the state, on its own or through its Regional Planning Organization (RPO) develops a list of sources that; were installed between August 1962 and August 1977, belong to one of the 26 named source categories listed in Table 1., and have aggregated potential emissions within a single category exceeding 250 tons per year for any one of the BART pollutants; sulfur dioxide, nitrogen oxides, particulate matter, VOC.

Table 1. 26 Named Source Categories Where BART-Eligible Source May be Found

(1) Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input
(2) Coal cleaning plants (thermal dryers)
(3) Kraft pulp mills
(4) Portland cement plants
(5) Primary zinc smelters
(6) Iron and steel mill plants
(7) Primary aluminum ore reduction plants
(8) Primary copper smelters
(9) Municipal incinerators capable of charging more than 250 tons of refuse per day
(10) Hydrofluoric, sulfuric, and nitric acid plants
(11) Petroleum refineries
(12) Lime plants
(13) Phosphate rock processing plants
(14) Coke oven batteries
(15) Sulfur recovery plants
(16) Carbon black plants (furnace process)
(17) Primary lead smelters
(18) Fuel conversion plants
(19) Sintering plants
(20) Secondary metal production facilities
(21) Chemical process plants
(22) Fossil-fuel boilers of more than 250 million British thermal units per hour heat input
(23) Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels
(24) Taconite ore processing facilities
(25) Glass fiber processing plants
(26) Charcoal production facilities.

The Riley Boiler at the Ontonagon facility is subject to BART under source category 22, Fossil-fuel boilers of more than 250 million British thermal units per hour heat input.

3.2 Determine 'Reasonable Cause or Contribution to Visibility Impairment'

Following identification of BART-eligible sources, the states were to determine whether the sources collectively impaired visibility at a Class I area, and whether a specific source could cause or contribute to impairment. In general terms, this involved determining whether the amount of pollutant emitted and the distance of the source from the Class I area allowed emissions from the source to impact visibility in the Class I area. In the *Guidelines for BART Determinations Under the Regional Haze Rules* (Appendix Y to 40 CFR Part 51), EPA defined 'causing impairment' as demonstrating a modeled impact on visibility exceeding 1.0 deciviews. A source was said to 'contribute to impairment' if its modeled visibility impact exceeded 0.5 deciviews. Further, EPA specified that those thresholds be evaluated based on the 98th percentile modeled impact, which means that the impacts must be indicated for more than seven days per year.

> ***What is a deciview? A deciview is defined as an atmospheric haze metric that expresses uniform changes in visibility regardless of the background. A one deciview change in visibility is thought to be the level of perceptible change that can be noted with the human eye. The measure is related mathematically to the common visibility parameters of light extinction coefficients and visual range; however, it remains a somewhat subjective measure.***

The states were given a variety of options for determining whether the BART-eligible source could reasonably cause or contribute to impairment.

- Decide that all BART-eligible sources in the state do cause or contribute to visibility impairment.
- Demonstrate that all of the BART-eligible sources do NOT cause or contribute to visibility impairment.
- Evaluate BART-eligible sources individually to determine whether they contribute to visibility impairment. This could be accomplished by using an emission rate-to-distance (Q/D) from the Class I area metric, or via regional modeling.
- Use a conservative 'model facility' approach that establishes very conservative parameters for a facility, then modeling the impacts of that facility to estimate which BART eligible sources may cause or contribute to visibility impairment.

Michigan has chosen to use the individual source evaluation method.

3.3 State/RPO BART Applicability Determinations

The Michigan Department of Environmental Quality (MDEQ), through the regional planning organization, Lake Michigan Air Directors Consortium (LADCO), conducted modeling of all sources to determine impacts to visibility in Class I areas. The model was developed by LADCO using 2004 MAERS inventory data for the Riley Boiler at the Smurfit-Stone facility (although PM emissions were omitted). The model evaluated visibility impacts from the Riley Boiler upon four Class I areas that fall within the 500 kilometer radius of the facility. Of the four Class I areas evaluated, Voyageur's National Park and Boundary Water Canoe Area in Minnesota, and Seney Wilderness and Isle Royale in Michigan, impacts were indicated only at Isle Royale.

The LADCO model indicated visibility impacts exceeding 0.5 deciviews for more than seven days for the years 2002, 2003 and 2004 meteorological data sets. We have rerun the original LADCO model using their selected model settings and background concentration assumptions, but with two exceptions: LADCO had originally modeled using background values for ammonium sulfate and organic carbon that were established for the Western U.S. – we have changed those background values to reflect the more appropriate Eastern U.S. values. Secondly, we have included the PM emissions that were mistakenly omitted from the original LADCO analysis.

Table 2. LADCO Model Results Using 2004 MAERS Data

Met Year	Days > 0.5 dv
2002	22
2003	21
2004	11

The results of the LADCO model run using the 2004 MAERS emission data, predicts that the Riley Boiler contributes to visibility impairment at Isle Royale.

3.4 Updating the Baseline

Since the baseline emissions were established in 2004, SSCC has implemented additional controls that have reduced the emission of visibility impairing pollutants. As a result, the visibility impact of the Riley Boiler has also been reduced from that indicated by the LADCO baseline model results. In the preamble to the July 20, 2001 Proposed BART Determination Guidelines, EPA says "For purposes of estimating actual emissions, these guidelines take a similar approach to the current definition of actual emissions in NSR programs. That is, the baseline emissions are the average annual emissions from the two most recent years…" This approach was unchanged in the July 6, 2005 final rule. Table 3 presents the MAERS emission inventory information for years 2005 and 2006 and the average of emissions during those two years.

Table 3. 2005, 2006 and Average MAERS Data for Smurfit Stone

Pollutant	2005 (TPY)	2006 (TPY)	Two-Year Average
SO2	2914	2846	2880
NOx	715	628	671.5
PM10	37	38	37.5

Modeling of visibility impacts at Isle Royale was then completed using the updated baseline condition. Table 4 lists the number of days each modeled year with visibility impacts exceeding the 0.5 dv change threshold. Use of the updated baseline period shows that reductions already made by SSCC have significantly reduced the predicted impacts.

Table 4. Model-Predicted Visibility Impacts Using the Updated 2005-2006 Emissions Data

Met Year	Days > 0.5 dv
2002	17
2003	15
2004	7

3.5 Impacting Isle Royale?

As stated on the official Isle Royale Park Service website, Isle Royale "*is one of the few national parks to close during the winter.*" The Park is closed from November 1 through April 16 and operates under reduced hours during May, June and September. Due to harsh conditions, even park management leaves the island during the winter months, relocating to Houghton, Michigan. Not only is the park 'closed' during the winter months, the Park Services states on their website that it is not possible to reach the park during these months:

> *"A National Atmospheric Deposition Program/National Trends Network (NADP/NTN) wet deposition monitor has been operating at Wallace Lake in Isle Royale NP (site #MI97) since 1985. Because the site can't be accessed for winter sampling, data don't meet the completeness criteria required by NADP/NTN for a trend analysis."*

(From http://www2.nature.nps.gov/air/Permits/ARIS/isro/ (accessed March 21, 2007))

Isle Royale differs from the majority of Class I areas because there is no physical way for the park to be observed by visitors, day or night, for nearly half of the year. This brings into question whether it is appropriate to calculate visibility impact values in the same manner for Isle Royale as for other Class I areas which are staffed and open to visitors on a year-round basis. Considering that the park is closed for 5.5 months, or 46 percent of the year, SSCC proposes that the updated baseline case could be represented as shown in Table 5 below, where the number of days with predicted impact exceeding 0.5 dv is multiplied by the 54 percent of the year that the park is operating. It should also be noted that no additional adjustment was made for the significant amount of time that the park is open, but operating under reduced hours.

Table 5. Updated Baseline Model Results Scaled for Park Closure Period

Met Year	Days > 0.5 dv
2002	9.18
2003	8.10
2004	3.78

Taking the average of the values shown in Table 5 leads to an average of 7.02 days with predicted visibility impact greater than 0.5 dv. This is less than the 98th percentile value for number of days per year : (365 * (1-0.98) = 7.3 days with deciview changes greater than 0.5 dv) , which indicates that the Riley Boiler does not contribute to visibility impairment at Isle Royale. Per the Regional Haze Regulations, BART requirements apply only to sources that may reasonably be anticipated to cause or contribute to impairment of visibility in a Class I area.

SSCC urges that MDEQ determine that the Riley Boiler can not be found to reasonably cause or contribute to appreciable visibility degradation at Isle Royale, and therefore BART does not apply to the Riley Boiler.

4.0 Summary

Smurfit Stone Container Corporation (SSCC) believes that the Riley Boiler at the Ontonagon, Michigan facility does not sufficiently impact visibility at Isle Royale to require installation of BART controls. The continuous improvement in boiler operation and control over recent years, and the current installation of controls to meet requirements of the Boiler MACT have or will reduce potential visibility impacts from the boiler. This claim is further strengthened by the fact that Isle Royale is unique among Class I areas in that there is virtually no access to the park for nearly half of the year. By discounting the modeled visibility impacts to reflect this lack of access, it appears that the Riley Boiler may produce visibility impacts of greater than 0.5 deciviews on an average of only 7.02 days per year, which is below the 7.3 day threshold that is the 98th percentile value as specified in the BART regulations. SSCC therefore concludes that the Riley Boiler does not cause or contribute to visibility impairment in a Class I areas and therefore, is not subject to the requirement to install BART controls.

Appendix A

CALPUFF Protocol

CALPUFF Protocol

The following model settings were employed in all modeling described in this report. In an effort to facilitate the MDEQ review process, SSCC chose to use the regional modeling approach conducted by LADCO with only minor modifications or corrections. Model output files from CALPUFF and the CALPOST utility are included in the appendices to this report.

CALPUFF Modeling Protocol for SSCC BART Impacts Analysis

Model Selection

Regional visibility modeling was performed for the Smurfit Stone Container Corporation (SSCC) in Ontonagon, Michigan, using Bee-Line Software's Professional CALPUFF Version 2.34.0, a Graphical User Interface (GUI) which interfaces with the EPA CALPUFF 2004 Version. This program implements CALPUFF version 5.756 and CALPOST version 5.6393.

Modeling Protocol

The modeling protocols supplied by the Midwest Regional Planning Organization (MRPO) and LADCO were consulted during the development of the SSCC facility model. Recommended default model values were taken from the LADCO protocol. The Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Report and Recommendations for Modeling Long Range Transport Impacts was also consulted during the development of the model and served as the starting point for the SSCC modeling effort.

Modeling Domain

The CALPUFF modeling domain is the RPO grid used by LADCO, a Lambert conformal grid projection centered at 97W, 40N with true latitudes at 33N and 45N and origin at -900 km, -1620 km. There are 97 36-km grid cells in the east-west direction and 90 36-km grid cells in the north –south direction to make up the horizontal domain. The vertical domain contains 16 layers up to 15 km in the atmosphere with higher resolution in the boundary layer.

Meteorological Data

Meteorological data were supplied by LADCO. The CALMET data files were created using MM5 output files. All meteorological data are in 36 km resolution. Each met file contains the data for one day. To retain consistency with the LADCO model, no observation data were added to the MM5-generated CALMET files. The LADCO data set includes calendar years 2002, 2003 and 2004.

Terrain

Terrain effects were incorporated by LADCO in the development of the MM5 data and 36-km grid development.

Receptors

Pre-defined receptors established by the Federal Land Managers were added to the Federal Class I Area of Isle Royale. A total of 966 receptors at ground level are included in the Class I area.

Species Modeled

Sulfur dioxide, sulfate, nitrogen oxides, nitric acid, nitrates and particulate matter less than 10 micrometers in diameter (PM_{10}) are the species modeled for the SSCC facility. Sulfur dioxide, nitrogen oxides and PM_{10} are modeled as emitted and all species are modeled as deposited. The CALPUFF chemical transformation algorithms general sulfate and nitrate concentrations.

Model Settings

The model was set to output for concentrations and visibility in 24-hour averages. Visibility settings identified sulfate, nitrate, and coarse particles (PM_{10}) to be included in computing total light extinction. Rayleigh scattering was set equal to 10. The particle growth curve for hygroscopic species was set to the FLAG (2000) f(RH) tabulation. The method used for background light extinction is Method 6; FLAG RH adjustment factor applied to observed and modeled sulfates and nitrates computed using monthly relative humidity factors. The relative humidity factors used for each month are listed in Table 6 below. Table 7 shows the monthly background concentrations used. In both cases, values are taken directly from LADCO.

Table 6. Assumed Background Relative Humidity Values

Month	Relative Humidity	Month	Relative Humidity
January	3.1	July	3.0
February	2.5	August	3.2
March	2.7	September	3.8
April	2.4	October	2.7
May	2.2	November	3.3
June	2.6	December	3.3

Table 7. Assumed Monthly Background Concentrations

Component	Background Concentration ($\mu g/m^3$)
Ammonium sulfate	0.2
Ammonium nitrate	0.1

Component	Background Concentration (μg/m³)
Coarse particles	3.0
Organic carbon	1.5
Soil	0.5
Elemental carbon	0.02

Model Settings Compared to Default Values

Both IWAQM and LADCO recommend default model settings in their modeling protocols. These default settings have been used for most variables in the model. The CALPUFF variables, the IWAQM default value, the LADCO default value and the value used in the SSCC model are shown in Table 8 below. Any differences are highlighted in gray and are explained below. Where IWAQM and LADCO guidance differed, the SSCC model generally follows the LADCO methodology. CALPOST defaults are shown in Table 9.

Table 8. CALPUFF Settings and Default Values

Input Group	Variable	Description	IWAQM Default	LADCO Default	SSCC Model Value
1	AVET	Minutes	60	60	60
1	PGTIME	Minutes		60	60
2	MGAUSS	1=Gaussian	1	1	1
2	MCTADJ	3=partial plume path adjustment	3	3	3
2	MCTSG	Subgrid-scale complex terrain flag modeled?	No	No	No
2	MSLUG	Near-field puffs modeled as elongated?	No	No	No
2	MTRANS	Transitional plume rise modeled?	Yes	Yes	Yes
2	MTIP	Stack Tip Downwash Used?	Yes	Yes	Yes
2	MSHEAR	Vertical wind shear modeled?	No	No	No
2	MSPLIT	Puff splitting allowed?	No	No	No
2	MAQCHEM	Aqueous phase transformation modeled?		No	No
2	MWET	Wet removal modeled?	Yes	Yes	Yes
2	MDRY	Dry deposition modeled?	Yes	Yes	Yes
2	MDISP	Dispersion Coefficients used	3 PG dispersion coefficients for RURAL areas (computed using ISCST multi-segment approximation) and MP coefficients in	3 PG dispersion coefficients for RURAL areas (computed using ISCST multi-segment approximation) and MP coefficients in	3 PG dispersion coefficients for RURAL areas (computed using ISCST multi-segment approximation)

Input Group	Variable	Description	IWAQM Default	LADCO Default	SSCC Model Value
			urban areas	urban areas	and MP coefficients in urban areas
2	MROUGH	PG sigma-y,z adjusted for roughness?	No	No	No
2	MPARTL	Model partial plume penetration?	Yes	Yes	Yes
2	MPDF	Use PDF for convective dispersion	No	No	No
2	MSGTIBL	Use TIBL module?	No	No	No
4	MESHDN	Nesting factor for sampling grid?	Yes	Yes	Yes
9	RCUTR	Reference cuticle resistance (s/cm)	30	30	30
9	RGR	Reference ground resistance (s/cm)	10	10	10
9	REACTR	Reference reactivity	8	8	8
9	NINT	Number of particle-size intervals	9	9	9
9	IVEG	Vegetation state in unirrigated areas active and unstressed?	Yes	Yes	Yes
11	BCKO3	Background Ozone concentrations (ppb per month)	80, 80, 80, 80, 80, 80, 80, 80, 80, 80, 80, 80	31, 31, 31, 37, 37, 37, 33, 33, 33, 27, 27, 27	31, 31, 31, 37, 37, 37, 33, 33, 33, 27, 27, 27
11	BCKNH3	Background ammonia concentrations (ppb per month)	10, 10, 10, 10, 10, 10, 10, 10, 10, 10, 10, 10	0.3, 0.3, 0.3, 0.5, 0.5, 0.5, 0.5, 0.5, 0.5, 0.5, 0.5, 0.5	0.3, 0.3, 0.3, 0.5, 0.5, 0.5, 0.5, 0.5, 0.5, 0.5, 0.5, 0.5
11	RNITE1	Nighttime SO2 loss rate (%/hr)	0.2	0.2	0.2
11	RNITE2	Nighttime NOx loss rate (%/hr)	2.0	2.0	2.0
11	RNITE3	Nighttime HNO3 loss rate (%/hr)	2.0	2.0	2.0
12	SYTDEP	Horizontal size (m) to switch to time dependence	550	550	550
12	MHFTSZ	Use Heffter for vertical dispersion?	No	No	No
12	JSUP	PG Stability class above mixed layer	5	5	5
12	CONK1	Stable dispersion constant	0.01	0.01	0.01
12	CONK2	Neutral dispersion constant	0.1	0.1	0.1
12	TBD	Transition for downwash algorithms	0.5 ISC Transition-point	0.5 ISC Transition-point	0.5 ISC Transition-point
12	IURB1	Beginning urban landuse type	10	10	10
12	IURB2	Ending urban landuse type	19	19	19
12	XMXLEN	Maximum slug length in units of DGRIDKM	1.0	1.0	1.0

Input Group	Variable	Description	IWAQM Default	LADCO Default	SSCC Model Value
12	XSAMLEN	Maximum puff travel distance per sampling step (units of DGRIDKM)	1.0	1.0	1.0
12	MXNEW	Maximum number of puffs per hour	99	99	99
12	MXSAM	Maximum sampling steps per hour	99	99	99
12	NCOUNT	Number of iterations used when computing the transport wind for a sampling step that includes gradual rise		2	2
12	SYMIN	Minimum lateral dispersion of new purr (m)	1.0	1.0	1.0
12	SZMIN	Minimum vertical dispersion of new puff (m)	1.0	1.0	1.0
12	SVMIN	Array of minimum lateral turbulence (m/s)	0.5, 0.5, 0.5, 0.5, 0.5, 0.5 for land 0.37, 0.37, 0.37, 0.37, 0.37, 0.37 for water	0.5, 0.5, 0.5, 0.5, 0.5, 0.5 for land 0.37, 0.37, 0.37, 0.37, 0.37, 0.37 for water	0.5, 0.5, 0.5, 0.5, 0.5, 0.5 for land 0.37, 0.37, 0.37, 0.37, 0.37, 0.37 for water
12	SWMIN	Array of minimum vertical turbulence (m/s)	0.20, 0.12, 0.08, 0.06, 0.03, 0.016	0.20, 0.12, 0.08, 0.06, 0.03, 0.016	0.20, 0.12, 0.08, 0.06, 0.03, 0.016
12	CDIV	Divergence criterion for dw/dz across puff used to initiate adjustment for horizontal convergence (1/s)	0.01	0.00, 0.00	0.00, 0.00
12	WSCALM	Minimum wind speed (m/s) allowed for non-calm conditions	0.5	0.5	0.5
12	XMAXZI	Maximum mixing height (m)	3000	3000	3000
12	XMINZI	Minimum mixing height (m)	50	50	50
12	WSCAT	Default wind speed classes		1.54, 3.09, 5.14, 8.23, 10.8	1.54, 3.09, 5.14, 8.23, 10.8
12	PLX0	Default wind speed profile power-law exponents for stabilities 1-6		0.07, 0.07, 0.10, 0.15, 0.35, 0.55	0.07, 0.07, 0.10, 0.15, 0.35, 0.55
12	PTG0	Default potential temperature gradient for stable classes E, F (deg K/m)	0.020, 0.035	0.020, 0.035	0.020, 0.035
12	PPC	Default plume path coefficients for each stability class	0.50, 0.50, 0.50, 0.50, 0.35, 0.35	0.50, 0.50, 0.50, 0.50, 0.35, 0.35	0.50, 0.50, 0.50, 0.50, 0.35, 0.35
12	SL2PF	Slug-to-puff transition criterion factor equal to sigma-y/length of slug		10	10

Input Group	Variable	Description	IWAQM Default	LADCO Default	SSCC Model Value
12	NSPLIT	Number of puffs that result every time a puff is split vertically	3	3	3
12	IRESPLIT	Time of day when split puffs are eligible to be split once again; typically set once per day around sunset before nocturnal shear develops	User Defined	17	17
12	ZISPLIT	Previous hour's mixing height (minimum) (m)	100	100	100
12	ROLDMAX	Previous maximum mixing height / current mixing height ratio, must be less than this value to allow puff split	0.25	0.25	0.25
12	NSPLITH	Number of puffs that result every time a puff is split horizontally		5	5
12	SYSPLITH	Minimum sigma-y (grid cell units) of puff before it may be split		1.0	1.0
12	SHSPLITH	Minimum puff elongation rate (SYSPLIT/hr) due to wind shear before it may be split		2.0	2.0
12	CNSPLITH	Minimum concentration (g/m3) of each species in puff before it may be split		1.0E-07	1.0E-07
12	EPSSLUG	Fractional convergence criterion for numerical SLUG sampling integration	1.0E-04	1.0E-04	1.0E-04
12	EPSAREA	Fractional convergence criterion for numerical AREA source integration	1.0E-06	1.0E-06	1.0E-06
12	DSRISE	Trajectory step-length (m) used for numerical rise integration		1.0	1.0

The SSCC model uses the same defaults as employed by LADCO for CALPOST. IWAQM did not provide default CALPOST values in the Phase 2 report.

Table 9. CALPOST Settings and Default Values for Extinction Efficiency

Variable	LADCO Default	SSCC Model Value
EEPMC	0.6 Modeled PM Coarse	0.6 Modeled PM Coarse
EEPMF	1.0 Modeled PM Fine	1.0 Modeled PM Fine
EEPMCBK	0.6 Background PM Coarse	0.6 Background PM Coarse
EESO4	3.0 Ammonium Sulfate	3.0 Ammonium Sulfate

Variable	LADCO Default	SSCC Model Value
EENO3	3.0 Ammonium Nitrate	3.0 Ammonium Nitrate
EEOC	4.0 Organic Carbon	4.0 Organic Carbon
EESOIL	1.0 Soil	1.0 Soil
EEEC	10.0 Elemental Carbon	10.0 Elemental Carbon

Variables Adjusted from IWAQM and/or LADCO Defaults

CDIV

The LADCO default and the value used for the SSCC model for CDIV, the divergence criterion for dw/dz across the puff used to initiate adjustment for horizontal convergence (1/s) was set at 0.0, 0.0. This differs from the IWAQM recommended setting value equal to 0.01.

BCK03

The IWAQM recommended default for background ozone concentrations is 80 ppb for all months. This value should only be used for missing data. SSCC employed the LADCO defaults for background ozone concentration of 31 ppb for January, February and March; 37 ppb for April, May and June; 33 ppb for July, August, September, and 27 ppb for October, November and December.

BCKNH3

The background ammonia concentration recommended by IWAQM is 10 ppb for all months. The LADCO background concentrations for ammonia are 0.3 ppb in January, February and March and 0.5 ppb for the rest of the year. The LADCO default values were used in the SSCC model.

Source Parameters

The source parameters for the Riley Boiler as entered into the CALPUFF model in Input Group 13 are shown in Table 10 below.

Table 10. Source Parameters Modeled for the Riley Boiler

Variable	Parameter
Source ID	1
UTM X (km)	780.0257
UTM Y (km)	5197.3649
Zone	15
Stack Height (m)	61.1400
Base Elevation (m)	198.0000
Stack Diameter (m)	2.2900
Exit Velocity (m/s)	17.6200
Exit Temperature (K)	445.3700

Appendix B

2005-2006
Baseline Model Output Files

Appendix 9O

Emission Limits – Excerpts from ROP for Smurfit- Stone Container Company

Michigan Department of Environmental Quality
Air Quality Division

EFFECTIVE DATE: January 1, 2007
REVISION DATES: June 13, 2007; November 13, 2007; June 29, 2009

ISSUED TO:

Smurfit-Stone Container Enterprises, Inc.
d/b/a Smurfit-Stone Container Corporation

State Registration Number (SRN): A5754

LOCATED AT:

One Superior Way, Ontonagon, Michigan 49953

RENEWABLE OPERATING PERMIT

Permit Number: MI-ROP-A5754-2007c

Expiration Date: December 31, 2011

Administratively Complete ROP Renewal Application Due Between July 1, 2010 and July 1, 2011

This Renewable Operating Permit (ROP) is issued in accordance with and subject to Section 5506(3) of Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (Act 451). Pursuant to Michigan Air Pollution Control Rule 210(1), this ROP constitutes the permittee's authority to operate the stationary source identified above in accordance with the general conditions, special conditions and attachments contained herein. Operation of the stationary source and all emission units listed in the permit are subject to all applicable future or amended rules and regulations pursuant to Act 451 and the federal Clean Air Act.

SOURCE-WIDE PERMIT TO INSTALL

Permit Number: MI-PTI-A5754-2007c

This Permit to Install (PTI) is issued in accordance with and subject to Section 5505(5) of Act 451. Pursuant to Michigan Air Pollution Control Rule 214a, the terms and conditions herein, identified by the underlying applicable requirement citation of Rule 201(1)(a), constitute a federally enforceable PTI. The PTI terms and conditions do not expire and remain in effect unless the criteria of Rule 201(6) are met. Operation of all emission units identified in the PTI is subject to all applicable future or amended rules and regulations pursuant to Act 451 and the federal Clean Air Act.

Michigan Department of Environmental Quality

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William A. Presson, Acting Permit Section Supervisor

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AUTHORITY AND ENFORCEABILITY

For the purpose of this permit, the **permittee** is defined as any person who owns or operates an emission unit at a stationary source for which this permit has been issued. The **department** is defined in Rule 104(d) as the Director of the Michigan Department of Environmental Quality (MDEQ) or his or her designee.

The permittee shall comply with all specific details in the permit terms and conditions and the cited underlying applicable requirements. All terms and conditions in this ROP are both federally enforceable and state enforceable unless otherwise footnoted. Certain terms and conditions are applicable to most stationary sources for which an ROP has been issued. These general conditions are included in Part A of this ROP. Other terms and conditions may apply to a specific emission unit, several emission units which are represented as a flexible group, or the entire stationary source which is represented as a source-wide group. Special conditions are identified in Parts B, C, D and/or the appendices.

In accordance with Rule 213(2)(a), all underlying applicable requirements will be identified for each ROP term or condition. All terms and conditions that are included in a PTI, are streamlined or subsumed, or are state-only enforceable will be noted as such.

In accordance with Section 5507 of Act 451, the permittee has included in the ROP application a compliance certification, a schedule of compliance, and a compliance plan. For applicable requirements with which the source is in compliance, the source will continue to comply with these requirements. For applicable requirements with which the source is not in compliance, the source will comply with the detailed schedule of compliance requirements that are incorporated as an appendix in this ROP. Furthermore, for any applicable requirements effective after the date of issuance of this ROP, the stationary source will meet the requirements on a timely basis, unless the underlying applicable requirement requires a more detailed schedule of compliance.

Issuance of this permit does not obviate the necessity of obtaining such permits or approvals from other units of government as required by law.

A. GENERAL CONDITIONS

Permit Enforceability

- All conditions in this permit are both federally enforceable and state enforceable unless otherwise noted. **(R 336.1213(5))**

- Those conditions that are hereby incorporated in a state only enforceable Source-wide PTI pursuant to Rule 201(2)(d) are designated by footnote one. **(R 336.1213(5)(a), R 336.1214a(5))**

- Those conditions that are hereby incorporated in federally enforceable Source-wide PTI No. MI-PTI-A5754-2007c pursuant to Rule 201(2)(c) are designated by footnote two. **(R 336.1213(5)(b), R 336.1214a(3))**

General Provisions

1. The permittee shall comply with all conditions of this ROP. Any ROP noncompliance constitutes a violation of Act 451, and is grounds for enforcement action, for ROP revocation or revision, or for denial of the renewal of the ROP. All terms and conditions of this ROP that are designated as federally enforceable are enforceable by the Administrator of the United States Environmental Protection Agency (USEPA) and by citizens under the provisions of the federal Clean Air Act (CAA). Any terms and conditions based on applicable requirements which are designated as “state only” are not enforceable by the USEPA or citizens pursuant to the CAA. **(R 336.1213(1)(a))**

2. It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this ROP. **(R 336.1213(1)(b))**

3. This ROP may be modified, revised, or revoked for cause. The filing of a request by the permittee for a permit modification, revision, or termination, or a notification of planned changes or anticipated noncompliance does not stay any ROP term or condition. This does not supersede or affect the ability of the permittee to make changes, at the permittee’s own risk, pursuant to Rule 215 and Rule 216. **(R 336.1213(1)(c))**

4. The permittee shall allow the department, or an authorized representative of the department, upon presentation of credentials and other documents as may be required by law and upon stating the authority for and purpose of the investigation, to perform any of the following activities **(R 336.1213(1)(d))**:
   a. Enter, at reasonable times, a stationary source or other premises where emissions-related activity is conducted or where records must be kept under the conditions of the ROP.
   b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the ROP.
   c. Inspect, at reasonable times, any of the following:
      i. Any stationary source.
      ii. Any emission unit.
      iii. Any equipment, including monitoring and air pollution control equipment.
      iv. Any work practices or operations regulated or required under the ROP.
   d. As authorized by Section 5526 of Act 451, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the ROP or applicable requirements.

5. The permittee shall furnish to the department, within a reasonable time, any information the department may request, in writing, to determine whether cause exists for modifying, revising, or revoking the ROP or to determine compliance with this ROP. Upon request, the permittee shall also furnish to the department copies of any records that are required to be kept as a term or condition of this ROP. For information which is claimed by the permittee to be confidential, consistent with the requirements of the 1976 PA 442, MCL §15.231 et seq.,

and known as the Freedom of Information Act, the person may also be required to furnish the records directly to the USEPA together with a claim of confidentiality. **(R 336.1213(1)(e))**

6. A challenge by any person, the Administrator of the USEPA, or the department to a particular condition or a part of this ROP shall not set aside, delay, stay, or in any way affect the applicability or enforceability of any other condition or part of this ROP. **(R 336.1213(1)(f))**

7. The permittee shall pay fees consistent with the fee schedule and requirements pursuant to Section 5522 of Act 451. **(R 336.1213(1)(g))**

8. This ROP does not convey any property rights or any exclusive privilege. **(R 336.1213(1)(h))**

Equipment & Design

9. Any collected air contaminants shall be removed as necessary to maintain the equipment at the required operating efficiency. The collection and disposal of air contaminants shall be performed in a manner so as to minimize the introduction of contaminants to the outer air. Transport of collected air contaminants in Priority I and II areas requires the use of material handling methods specified in Rule 370(2). **(R 336.1370)**

10. Any air cleaning device shall be installed, maintained, and operated in a satisfactory manner and in accordance with the Michigan Air Pollution Control rules and existing law. **(R 336.1910)**

Emission Limits

11. Except as provided in Subrules 2, 3, and 4 of Rule 301, states in part; “a person shall not cause or permit to be discharged into the outer air from a process or process equipment a visible emission of a density greater than the most stringent of Rule 301(1)(a) or (b) unless otherwise specified in this ROP.” The grading of visible emissions shall be determined in accordance with Rule 303. **(R 336.1301(1) in pertinent part)**:
    a. A 6-minute average of 20 percent opacity, except for one 6-minute average per hour of not more than 27 percent opacity.
    b. A limit specified by an applicable federal new source performance standard.

12. The permittee shall not cause or permit the emission of an air contaminant or water vapor in quantities that cause, alone or in reaction with other air contaminants, either of the following:
    a. Injurious effects to human health or safety, animal life, plant life of significant economic value, or property. [1]**(R 336.1901(a))**
    b. Unreasonable interference with the comfortable enjoyment of life and property. [1]**(R 336.1901(b))**

Testing/Sampling

13. The department may require the owner or operator of any source of an air contaminant to conduct acceptable performance tests, at the owner’s or operator’s expense, in accordance with Rule 1001 and Rule 1003, under any of the conditions listed in Rule 1001(1). **(R 336.2001)**

14. Any required performance testing shall be conducted in accordance with Rule 1001(2), Rule 1001(3) and Rule 1003. **(R 336.2001(2), R 336.2001(3), R 336.2003(1))**

15. Any required test results shall be submitted to the Air Quality Division (AQD) in the format prescribed by the applicable reference test method within 60 days following the last date of the test. **(R 336.2001(4))**

Monitoring/Recordkeeping

16. Records of any periodic emission or parametric monitoring required in this ROP shall include the following information specified in Rule 213(3)(b)(i), where appropriate **(R 336.1213(3)(b))**:
    a. The date, location, time, and method of sampling or measurements.
    b. The dates the analyses of the samples were performed.
    c. The company or entity that performed the analyses of the samples.
    d. The analytical techniques or methods used.
    e. The results of the analyses.
    f. The related process operating conditions or parameters that existed at the time of sampling or measurement.

17. All required monitoring data, support information and all reports, including reports of all instances of deviation from permit requirements, shall be kept and furnished to the department upon request for a period of not less than five years from the date of the monitoring sample, measurement, report or application. Support information includes all calibration and maintenance records and all original strip-chart recordings, or other original data records, for continuous monitoring instrumentation and copies of all reports required by the ROP. **(R 336.1213(1)(e), R 336.1213(3)(b)(ii))**

Certification & Reporting

18. Except for the alternate certification schedule provided in Rule 213(3)(c)(iii)(B), any document required to be submitted to the department as a term or condition of this ROP shall contain an original certification by a responsible official which states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. **(R 336.1213(3)(c))**

19. A responsible official shall certify to the appropriate AQD District Office and to the USEPA that the stationary source is and has been in compliance with all terms and conditions contained in the ROP except for deviations that have been or are being reported to the appropriate AQD District Office pursuant to Rule 213(3)(c). This certification shall include all the information specified in Rule 213(4)(c)(i) through (v) and shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the certification are true, accurate, and complete. The USEPA address is: USEPA, Air Compliance Data - Michigan, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604. **(R 336.1213(4)(c))**

20. The certification of compliance shall be submitted annually for the term of this ROP as detailed in the special conditions, or more frequently if specified in an applicable requirement or in this ROP. **(R 336.1213(4)(c))**

21. The permittee shall promptly report any deviations from ROP requirements and certify the reports. The prompt reporting of deviations from ROP requirements is defined in Rule 213(3)(c)(ii) as follows, unless otherwise described in this ROP. **(R 336.1213(3)(c))**
    a. For deviations that exceed the emissions allowed under the ROP, prompt reporting means reporting consistent with the requirements of Rule 912 as detailed in Condition 25. All reports submitted pursuant to this paragraph shall be promptly certified as specified in Rule 213(3)(c)(iii).
    b. For deviations which exceed the emissions allowed under the ROP and which are not reported pursuant to Rule 912 due to the duration of the deviation, prompt reporting means the reporting of all deviations in the semiannual reports required by Rule 213(3)(c)(i). The report shall describe reasons for each deviation and the actions taken to minimize or correct each deviation.
    c. For deviations that do not exceed the emissions allowed under the ROP, prompt reporting means the reporting of all deviations in the semiannual reports required by Rule 213(3)(c)(i). The report shall describe the reasons for each deviation and the actions taken to minimize or correct each deviation.

22. For reports required pursuant to Rule 213(3)(c)(ii), prompt certification of the reports is described in Rule 213(3)(c)(iii) as either of the following **(R 336.1213(3)(c))**:

a. Submitting a certification by a responsible official with each report which states that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.
b. Submitting, within 30 days following the end of a calendar month during which one or more prompt reports of deviations from the emissions allowed under the ROP were submitted to the department pursuant to Rule 213(3)(c)(ii), a certification by a responsible official which states that, "based on information and belief formed after reasonable inquiry, the statements and information contained in each of the reports submitted during the previous month were true, accurate, and complete". The certification shall include a listing of the reports that are being certified. Any report submitted pursuant to Rule 213(3)(c)(ii) that will be certified on a monthly basis pursuant to this paragraph shall include a statement that certification of the report will be provided within 30 days following the end of the calendar month.

23. Semiannually for the term of the ROP as detailed in the special conditions, or more frequently if specified, the permittee shall submit certified reports of any required monitoring to the appropriate AQD District Office. All instances of deviations from ROP requirements during the reporting period shall be clearly identified in the reports. **(R 336.1213(3)(c)(i))**

24. On an annual basis, the permittee shall report the actual emissions, or the information necessary to determine the actual emissions, of each regulated air pollutant as defined in Rule 212(6) for each emission unit utilizing the emissions inventory forms provided by the department. **(R 336.1212(6))**

25. The permittee shall provide notice of an abnormal condition, start-up, shutdown, or malfunction that results in emissions of a hazardous or toxic air pollutant which continue for more than one hour in excess of any applicable standard or limitation, or emissions of any air contaminant continuing for more than two hours in excess of an applicable standard or limitation, as required in Rule 912, to the appropriate AQD District Office. The notice shall be provided not later than two business days after the start-up, shutdown, or discovery of the abnormal conditions or malfunction. Notice shall be by any reasonable means, including electronic, telephonic, or oral communication. Written reports, if required under Rule 912, must be submitted to the appropriate AQD District Supervisor within 10 days after the start-up or shutdown occurred, within 10 days after the abnormal conditions or malfunction has been corrected, or within 30 days of discovery of the abnormal conditions or malfunction, whichever is first. The written reports shall include all of the information required in Rule 912(5) and shall be certified by a responsible official in a manner consistent with the CAA. **(R 336.1912)**

Permit Shield

26. Compliance with the conditions of the ROP shall be considered compliance with any applicable requirements as of the date of ROP issuance, if either of the following provisions is satisfied. **(R 336.1213(6)(a)(i), R 336.1213(6)(a)(ii))**
a. The applicable requirements are included and are specifically identified in the ROP.
b. The permit includes a determination or concise summary of the determination by the department that other specifically identified requirements are not applicable to the stationary source.

Any requirements identified in Part E of this ROP have been identified as non-applicable to this ROP and are included in the permit shield.

27. Nothing in this ROP shall alter or affect any of the following:
a. The provisions of Section 303 of the CAA, emergency orders, including the authority of the USEPA under Section 303 of the CAA. **(R 336.1213(6)(b)(i))**
b. The liability of the owner or operator of this source for any violation of applicable requirements prior to or at the time of this ROP issuance. **(R 336.1213(6)(b)(ii))**
c. The applicable requirements of the acid rain program, consistent with Section 408(a) of the CAA. **(R 336.1213(6)(b)(iii))**
d. The ability of the USEPA to obtain information from a source pursuant to Section 114 of the CAA. **(R 336.1213(6)(b)(iv))**

28. The permit shield shall not apply to provisions incorporated into this ROP through procedures for any of the following:
    a. Operational flexibility changes made pursuant to Rule 215. **(R 336.1215(5))**
    b. Administrative Amendments made pursuant to Rule 216(1)(a)(i)-(iv). **(R 336.1216(1)(b)(iii))**
    c. Administrative Amendments made pursuant to Rule 216(1)(a)(v) until the amendment has been approved by the department. **(R 336.1216(1)(c)(iii))**
    d. Minor Permit Modifications made pursuant to Rule 216(2). **(R 336.1216(2)(f))**
    e. State-Only Modifications made pursuant to Rule 216(4) until the changes have been approved by the department. **(R 336.1216(4)(e))**

29. Expiration of this ROP results in the loss of the permit shield. If a timely and administratively complete application for renewal is submitted not more than 18 months, but not less than 6 months, before the expiration date of the ROP, but the department fails to take final action before the end of the ROP term, the existing ROP does not expire until the renewal is issued or denied, and the permit shield shall extend beyond the original ROP term until the department takes final action. **(R 336.1217(1)(c), R 336.1217(1)(a))**

Revisions

30. For changes to any process or process equipment covered by this ROP that do not require a revision of the ROP pursuant to Rule 216, the permittee must comply with Rule 215. **(R 336.1215, R 336.1216)**

31. A change in ownership or operational control of a stationary source covered by this ROP shall be made pursuant to Rule 216(1). **(R 336.1219(2))**

32. For revisions to this ROP, an administratively complete application shall be considered timely if it is received by the department in accordance with the time frames specified in Rule 216. **(R 336.1210(9))**

33. Pursuant to Rule 216(1)(b)(iii), Rule 216(2)(d) and Rule 216(4)(d), after a change has been made, and until the department takes final action, the permittee shall comply with both the applicable requirements governing the change and the ROP terms and conditions proposed in the application for the modification. During this time period, the permittee may choose to not comply with the existing ROP terms and conditions that the application seeks to change. However, if the permittee fails to comply with the ROP terms and conditions proposed in the application during this time period, the terms and conditions in the ROP are enforceable. **(R 336.1216(1)(c)(iii), R 336.1216(2)(d), R 336.1216(4)(d))**

Reopenings

34. A ROP shall be reopened by the department prior to the expiration date and revised by the department under any of the following circumstances:
    a. If additional requirements become applicable to this stationary source with three or more years remaining in the term of the ROP, but not if the effective date of the new applicable requirement is later than the ROP expiration date. **(R 336.1217(2)(a)(i))**
    b. If additional requirements pursuant to Title IV of the CAA become applicable to this stationary source. **(R 336.1217(2)(a)(ii))**
    c. If the department determines that the ROP contains a material mistake, information required by any applicable requirement was omitted, or inaccurate statements were made in establishing emission limits or the terms or conditions of the ROP. **(R 336.1217(2)(a)(iii))**
    d. If the department determines that the ROP must be revised to ensure compliance with the applicable requirements. **(R 336.1217(2)(a)(iv))**

Renewals

35. For renewal of this ROP, an administratively complete application shall be considered timely if it is received by the department not more than 18 months, but not less than 6 months, before the expiration date of the ROP. **(R 336.1210(7))**

Stratospheric Ozone Protection

36. If the permittee is subject to Title 40 of the Code of Federal Regulations (CFR), Part 82 and services, maintains, or repairs appliances except for motor vehicle air conditioners (MVAC), or disposes of appliances containing refrigerant, including MVAC and small appliances, or if the permittee is a refrigerant reclaimer, appliance owner or a manufacturer of appliances or recycling and recovery equipment, the permittee shall comply with all applicable standards for recycling and emissions reduction pursuant to 40 CFR, Part 82, Subpart F.

37. If the permittee is subject to 40 CFR, Part 82, and performs a service on motor (fleet) vehicles when this service involves refrigerant in the MVAC, the permittee is subject to all the applicable requirements as specified in 40 CFR, Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners. The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed by the original equipment manufacturer. The term MVAC as used in Subpart B does not include the air-tight sealed refrigeration system used for refrigerated cargo or an air conditioning system on passenger buses using Hydrochlorofluorocarbon-22 refrigerant.

Risk Management Plan

38. If subject to Section 112(r) of the CAA and 40 CFR, Part 68, the permittee shall register and submit to the USEPA the required data related to the risk management plan for reducing the probability of accidental releases of any regulated substances listed pursuant to Section 112(r)(3) of the CAA as amended in 40 CFR, Part 68.130. The list of substances, threshold quantities, and accident prevention regulations promulgated under 40 CFR, Part 68, do not limit in any way the general duty provisions under Section 112(r)(1).

39. If subject to Section 112(r) of the CAA and 40 CFR, Part 68, the permittee shall comply with the requirements of 40 CFR, Part 68, no later than the latest of the following dates as provided in 40 CFR, Part 68.10(a):
    a. June 21, 1999,
    b. Three years after the date on which a regulated substance is first listed under 40 CFR, Part 68.130, or
    c. The date on which a regulated substance is first present above a threshold quantity in a process.

40. If subject to Section 112(r) of the CAA and 40 CFR, Part 68, the permittee shall submit any additional relevant information requested by any regulatory agency necessary to ensure compliance with the requirements of 40 CFR, Part 68.

41. If subject to Section 112(r) of the CAA and 40 CFR, Part 68, the permittee shall annually certify compliance with all applicable requirements of Section 112(r) as detailed in Rule 213(4)(c)). **(40 CFR, Part 68)**

Emission Trading

42. Emission averaging and emission reduction credit trading are allowed pursuant to any applicable interstate or regional emission trading program that has been approved by the Administrator of the USEPA as a part of Michigan’s State Implementation Plan. Such activities must comply with Rule 215 and Rule 216. **(R 336.1213(12))**

Permit To Install (PTI)

43. The process or process equipment included in this permit shall not be reconstructed, relocated, or modified unless a PTI authorizing such action is issued by the department, except to the extent such action is exempt from the PTI requirements by any applicable rule.[2] **(R 336.1201(1))**

44. The department may, after notice and opportunity for a hearing, revoke PTI terms or conditions if evidence indicates the process or process equipment is not performing in accordance with the terms and conditions of the PTI or is violating the department's rules or the CAA.[2] **(R 336.1201(8), Section 5510 of Act 451)**

45. The terms and conditions of a PTI shall apply to any person or legal entity that now or hereafter owns or operates the process or process equipment at the location authorized by the PTI. If a new owner or operator submits a written request to the department pursuant to Rule 219 and the department approves the request, this PTI will be amended to reflect the change of ownership or operational control. The request must include all of the information required by Subrules (1)(a), (b) and (c) of Rule 219. The written request shall be sent to the appropriate AQD District Supervisor, MDEQ.[2] **(R 336.1219)**

46. If the installation, reconstruction, relocation, or modification of the equipment for which PTI terms and conditions have been approved has not commenced within 18 months, or has been interrupted for 18 months, the applicable terms and conditions from that PTI shall become void unless otherwise authorized by the department. Furthermore, the person to whom that PTI was issued, or the designated authorized agent, shall notify the department via the Supervisor, Permit Section, MDEQ, AQD, P. O. Box 30260, Lansing, Michigan 48909, if it is decided not to pursue the installation, reconstruction, relocation, or modification of the equipment allowed by the terms and conditions from that PTI.[2] **(R 336.1201(4))**

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

B. SOURCE-WIDE CONDITIONS

Part B outlines the Source-Wide Terms and Conditions that apply to this stationary source. The permittee is subject to these special conditions for the stationary source in addition to the general conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply to this source, N/A (not applicable) has been used in the table. If there are no Source-Wide Conditions, this section will be left blank.

C. EMISSION UNIT CONDITIONS

Part C outlines terms and conditions that are specific to individual emission units listed in the Emission Unit Summary Table. The permittee is subject to the special conditions for each emission unit in addition to the General Conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply, N/A (not applicable) has been used in the table. If there are no conditions specific to individual emission units, this section will be left blank.

EMISSION UNIT SUMMARY TABLE

The descriptions provided below are for informational purposes and do not constitute enforceable conditions.

Emission Unit ID	Emission Unit Description (Including Process Equipment & Control Device(s))	Control Device	Installation Date/ Modification Date	Flexible Group ID
EUCOPE	The Copeland Reactor is a chemical recovery furnace rated at 131 million BTU/hour; the Emission Unit includes a Chemical Recovery Storage Tank and a dissolving tank.	Cyclone, Venturi Scrubber, Packed Column Scrubber, Dissolving Tank Baghouse, Regenerative Thermal Oxidizer.	12/01/1989 01/01/1990 6/2009	N/A
EURB1	The No. 1 Riley Boiler is rated for 375 million BTU/hour and is capable of firing coal, wood, natural gas, No. 2 thru No. 6 fuel oil and noncondensible gases (NCGs) in compliance with 40 CFR 63 Subpart S.	Electro Static Precipitator, Cyclone.	01/01/1965 01/01/1983	N/A
EUFA1	An Ash Silo used to collect ash from the burning of coal or wood in the No. 1 Riley boiler.	Baghouse.	01/01/1965 01/01/1983	N/A
EUPB2A	The No. 2A package boiler is rated for 136 million BTUs/hour and is fired by natural gas with backup by No. 2 thru No. 6 fuel oil. It is also capable of incinerating NCGs in compliance with 40 CFR 63 Subpart S.		06/30/1986	N/A
EUPB3	The No. 3 package boiler is rated at 136 million BTU/hour and is fired by natural gas with backup by No. 2 thru No. 6 fuel oil. It is also capable of incinerating NCGs in compliance with 40 CFR 63 Subpart S.		06/01/1978	N/A
EUPB4	The No. 4 package boiler, rated for 65 million BTU/hour, is fired by natural gas. It is also capable of incinerating NCGs in compliance with 40 CFR 63 Subpart S.		06/01/1989	N/A

EUCOPE
EMISSION UNIT CONDITIONS

DESCRIPTION: The Copeland Reactor is a chemical recovery furnace rated at 131 million BTUs per hour heat input. Emission controls are by a cyclone, venturi scrubber, packed tower scrubber and a Regenerative Thermal Oxidizer (RTO).

POLLUTION CONTROL EQUIPMENT: Cyclone, venturi scrubber, packed tower scrubber and a regenerative thermal oxidizer.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Particulate matter (PM)	16 lbs/hour[2]	Per hour limit based on 3 hour average.	EUCOPE	V.1	R 336.1331, 40 CFR 52.21
2. Sulfur Dioxide (SO_2)	a. 2.62 lbs/hour[2]		EUCOPE	V.1	R 336.1402(2), 40 CFR 52.21
	b. Less than 0.02 lbs per MM BTUs heat input[2]	24 hour average.	EUCOPE	V.1	R 336.1201(3), 40 CFR 52.21
3. Nitrogen Oxides (NOx)	a. Less than 2.62 lbs per hour when controlled by the cyclone, venturi scrubber and packed tower scrubber[2]	Per hour.	EUCOPE	V.1	R366.1201(3), 40 CFR 52.21
	b. Less than 0.02 lbs per million BTUs heat input when controlled by the cyclone, venturi scrubber and packed tower scrubber[2]	24 hour average	EUCOPE	V.1	R 336.1201(3), 40 CFR 52.21
	c. Less than 63.0 lbs per hour when controlled by the cyclone, venturi scrubber, packed tower scrubber followed by the RTO[2]	24 hour average	EUCOPE	V.1	R 336.1201(3), 40 CFR 52.21
4. Carbon Monoxide (CO)	Less than 157.0 lbs per hour when controlled by the cyclone, venturi scrubber, packed tower scrubber followed by the RTO[2]	24 hour average	EUCOPE	V.1	R 336.1201(3), 40 CFR 52.21

II. MATERIAL LIMIT(S) N/A

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Permittee shall operate the Copeland reactor in accordance with a malfunction abatement plan to prevent, detect, and correct malfunctions or equipment failures resulting in emissions exceeding any applicable emission limitations. **(R 336.1911)**[1]

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. Permittee shall equip and maintain each scrubber with a liquid flow indicator. **(R 336.1201(3), R 336.1910)**[1]

2. Permittee shall not operate the Copeland reactor unless the cyclone, venture scrubber, and packed tower scrubber, are installed and operating properly. **(R 336.1201(3), R 336.1910, 40 CFR 52.21, 40 CFR 63 Subpart MM)**[2]

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall conduct stack testing of the Copeland/RTO, at the owner's expense, to verify compliance with the CO, PM, NOx, SO_2, RTO (VOC/HAP) destruction efficiency, and Gaseous organic HAPs. Testing shall be within the five year life of this permit and in accordance with Department requirements. A complete and acceptable test plan must be submitted 30 days prior to the test and approved prior to testing. See IX 5. **(R 336.1201(3))**

2. Acceptable performance testing shall be conducted by the permittee in accordance with R 336.2003. **(R 336.2003, R 336.2004)**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))]**

1. Permittee shall maintain records of the emission rates of PM, SO_2, and NOx from the Copeland reactor to demonstrate compliance with the pounds per hour and tons per year emission rates. **(R 336.1201(3))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1.SVCR-9S	60	144	**R 336.1201(3)**[1]
2.SVPSG-10S	76	144	**R 336.1201(3)**[1]

IX. OTHER REQUIREMENT(S)

1. Permittee shall ensure that the HAP emissions from the RTO as measured by total hydrocarbons reported as carbon, are reduced by at least 90 percent prior to discharge. **(R 336.1201(3), 40 CFR 63.862(c)(2)(ii))**

2. Permittee shall established an RTO operating temperature range as specified in 40 CFR 63.864(j) and operate the RTO within that range per 40 CFR 63.864(k). Permittee shall monitor and record the RTO operating temperature in a continuous basis and with instrumentation acceptable to the AQD. **(R 336.1201(3), R 336.1910, 40 CFR 63.864(j) & (k))**

3. The permittee shall comply with the general monitoring requirements under 40 CFR Section 63.864(a); and the on-going compliance provisions of 40 CFR Section 63.864 (k)(1)(iii). **(R 336.1910, 40 CFR 63.864(a))**

4. The permittee shall comply with the applicable recordkeeping requirements specified in 40 CFR Section 63.866(a)-(c)(1) and (c)(3)-(5) and the reporting requirements under 40 CFR Section 63.867(a), (b)(3)(i), (b)(3)(iii) and (c). **(R 336.1201(3), 40 CFR 63.866(a)-(c)(1), (c)(3)-(5), 40 CFR 63.867(a)(b)(3)(i) & (iii) and (c))**

5. The RTO efficiency test methods and procedures shall use Method 25A in appendix A of 40 CFR Part 60 as well as paragraphs (b)(5)(i)-(iv) of 40 CFR Part 63 Subpart MM Section 63.865. **(R 336.1201(3), 40 CFR 60 Appendix A, 40 CFR 63.865)**

6. The permittee shall not use any fuel other than natural gas or charcoal for start up of the Copeland reactor. **(R 336.1201(3), 40 CFR 52.21)**

7. The permittee shall not use any fuel other than natural gas and ultra low sulfur diesel oil as an auxiliary fuel in the Copeland reactor. **(R 336.1201(3), 40 CFR 52.21)**

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EURB1
EMISSION UNIT CONDITIONS

DESCRIPTION: The number 1 Riley Boiler, rated at 375 million BTU per hour, is capable of firing coal, wood, natural gas, and No. 2 through No. 6 fuel oil. The boiler is also capable of incinerating noncondensible gases (NCGs) in compliance with 40 CFR 63 Subpart S.

POLLUTION CONTROL EQUIPMENT: Particulate matter is controlled by a cyclone and an electrostatic precipitator.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. SO_2	a. The SO_2 emission rate while firing coal in the Riley Boiler shall not exceed 2.50 pounds per million BTUs heat input.[2]	24 hours	Riley Boiler	V.1	**R 336.1402**
	b. The SO_2 emission rate while firing coal in the Riley Boiler may be measured as usage of coal with a sulfur content not exceeding 1.5 % at a heat value of 12,000 BTUs per pound of coal[2]	N/A	Riley Boiler	V.1	**R 336.1402**
	c. The maximum sulfur content of fuel oil fired in the Riley Boiler shall not exceed 1.5% based on a heat value of 18,000 BTUs per pound of oil.[2]	N/A	Riley Boiler	V.1	**R 336.1201(3)**
2. NOx	Nitrogen oxides emissions shall not exceed 0.95 pounds per million BTU heat input averaged over the ozone control period. Total NOx emissions shall not exceed 350 pounds per hour.[1]	Ozone control period average (May 1 through September 30)	Riley Boiler	V.2	**R 336.1801(8)**
3. PM	The particulate emission from the Riley Boiler shall not exceed 0.25 pounds per 1,000 pounds of exhaust gases, corrected to 50% excess air.[2]	N/A	Riley Boiler	V.1	**R 336.1330, R 336.1331**

II. MATERIAL LIMIT(S) N/A

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Upon initiation of collector bypass, the input feed (excluding natural gas) to the Riley boiler shall cease immediately, consistent with safe operating procedures. Coal, oil, and or wood feed to the Riley boiler shall not restart until the collector is back on line and functioning properly. **(R 336.1301, R 336.1331)**[2]

2. The blow tank and evaporator systems shall be enclosed and vented into a closed vent system and routed to the No. 1 Riley boiler, or other onsite boiler capable of incinerating NCGs, and the permittee shall comply with the compliance date under 40 CFR 63.440(d) and the applicable requirements under 40 CFR 63.443 (d) and (e)(1). The enclosures and closed vent system shall meet the applicable requirements specified in 40 CFR 63.450. **(40 CFR 63, Subpart S)**[2]

IV. DESIGN/EQUIPMENT PARAMETER(S) N/A

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Permittee shall conduct a performance stack testing of the boiler to verify PM emission rates from the Riley boiler during the five year life of this ROP. Test method as specified in 40 CFR 63, Subpart S. **(R 336.1201(3), R 336.2001; 40 CFR 63, Subpart S; 40 CFR 60 Appendix A)**[2]

2. Permittee shall measure nitrogen oxides emissions from Riley Boiler by any of the following. **(R 336.1801(8))**
   a. Performance tests described in Rule 801(9).
   b. Through the use of continuous emission monitoring in accordance with the provisions of Rule 801(11).
   c. According to a schedule and method acceptable to the department.

3. The permittee shall obtain and keep records of the sulfur, ash, and BTU content of the coal burned in No. 1 Riley Boiler, as detailed in Appendix 4. **(R 336.1201(3))**[2]

See Appendix 4

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall operate the continuous opacity monitoring system on the duct serving No. 1 Riley Boiler. The permittee shall keep records of the opacity on a continuous basis and with instrumentation acceptable to the Air Quality Division. **(R 336.1201(3))**

2. The continuous opacity monitoring system shall comply with 40 CFR Part 60 Appendix B, Performance Specification 1. **(R 336.2150)**

3. The continuous opacity monitoring system shall comply with the cycling time requirements specified in Rule 1152. **(R 336.2152)**

4. The continuous opacity monitoring system shall comply with the zero and drift requirements specified in Rule 1153. **(R 336.2153)**

5. The continuous opacity monitoring system shall comply with the instrument span requirements specified in Rule 1154. (**R 336.2154)**

6. The continuous opacity monitoring system shall comply with the monitor location requirements specified in Rule 1155. **(R 336.2155)**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Within 60 days after the end of the ozone control period, the permittee shall submit a summary report in an acceptable format to the Air Quality Division to include all of the information specified in rule 801(12).[1] **(R 336.1801(12))**

3. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

4. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1.SVPSG-7S	120	195	**R 336.1201(3)**[1]

IX. OTHER REQUIREMENT(S) N/A

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUFA1
EMISSION UNIT CONDITIONS

DESCRIPTION: Ash silo, used to collect ash from the burning of coal and/or wood in the No. 1 Riley boiler.

POLLUTION CONTROL EQUIPMENT

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. PM	Emission from the fly ash silo shall not exceed 0.10 pounds per 1,000 lbs. of exhaust gases, calculated on a dry gas basis[2]	Test Protocol	Ash Silo	N/A	**R 336.1331**

II. MATERIAL LIMIT(S) N/A

III. PROCESS/OPERATIONAL RESTRICTION(S: N/A

IV. DESIGN/EQUIPMENT PARAMETER(S) N/A

V. TESTING/SAMPLING N/A

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Permittee shall keep records of Fugitive Dust Control Program specified in IX below. **(R 336.1213(3))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1.SVPSG-8S	N/A	N/A	N/A

IX. OTHER REQUIREMENT(S)

1. The permittee shall establish and implement a Fugitive Dust Control Program, which will include keeping a log for recording inspections, problems identified, repairs and/or corrective actions taken, and scheduled and completed maintenance to enclosures or other dust control or suppression mechanisms. The log shall also include observations of the Ash Handling and Storage activities and other actions taken to control fugitive dust. **(R 336.1213(3), R 336.1370)**

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUPB2A
EMISSION UNIT CONDITIONS

DESCRIPTION: The No. 2A package boiler is rated at 136 million BTUs per hour and is fired by natural gas with No. 2 through No. 6 fuel oils as back up. The boiler is capable of incinerating noncondensible gases in compliance with 40 CFR 63, Subpart S.

Flexible Group ID: N/A

POLLUTION CONTROL EQUIPMENT N/A

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. SO_2	a. SO_2 emissions shall not exceed 1.67 lbs. per billion BTUs heat input[2]	Per 24 hour period.	# 2A Package Boiler	Test Protocol	**R 336.1401, Table 42**
	b. SO_2 emissions shall not exceed117 tons[2]	Per year	# 2A Package Boiler	Test Protocol	**R 336.1201(3)**
	c. The maximum sulfur content of oil fired in the No. 2A boiler shall not exceed 1.5 percent[2]	Percent sulfur based on heat value of 18,000 BTUs per lb. of oil.	# 2A Package Boiler	Test Protocol	**R 336.1201(3)**
2. NOx	a. NOx emissions shall not exceed 74.8 lbs	per hour	# 2A Package Boiler	Test Protocol	**R 336.1201(3) AP-42**
	b. NOx emissions shall not exceed 150 tons	per year	# 2A Package Boiler	Test Protocol	**R 336.1201(3) AP-42**
3. PM	Visible emissions from the boiler shall not exceed a 6 minute average of 20% opacity while burning No. 2 through No. 6 fuel oil, except as specified in Rule 336.1301(1)(a)[2]		# 2A Package Boiler		**R 336.1301(1)(a), R 336.1303**

II. MATERIAL LIMIT(S)

Material	Limit	Equipment	Underlying Applicable Requirements
1. Fuel Oil	Permittee shall not burn more than 990,000 gallons of No. 6 fuel oil per year.	# 2A Package Boiler	**R 336.1201(3), 40 CFR 52.21**

Material	Limit	Equipment	Underlying Applicable Requirements
2. Natural Gas	Permittee shall not burn more than 545.4 million cubic feet of natural gas per year, except when No. 6 fuel oil is used in the 2A package boiler, the maximum allowed natural gas usage shall be reduced by applying the following equation: (545.4 – 0.122G) million cubic feet of natural gas per year, where G is No. 6 fuel oil usage in thousands of gallons.	# 2A Package Boiler	**R 336.1201(3), 40 CFR 52.21**

III. PROCESS/OPERATIONAL RESTRICTION(S) N/A

IV. DESIGN/EQUIPMENT PARAMETER(S) N/A

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Permittee shall conduct performance stack testing of one package boiler (Package Boiler # 2A, #3, or #4) to determine compliance with the NOx emission limitations within five years of issuance of this ROP. The package boiler tested and the test method shall be approved by the Department. **(R 336.1213(3), R 336.2001)**

2. Visible observation of the boiler emissions shall be conducted as specified in the Inspection and Maintenance Program. **(R 336.1301, R 336.1303)**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Records shall be kept in accordance with the Inspection and Maintenance Program, specified in IX. The records shall include but not be limited to, records of inspections, problems identified, repairs and or corrective action taken, scheduled and completed maintenance, and records of visual observations to assure compliance with Rule 336.1301 and Rule 336.1901. **(R 336.1213(3), R 336.1301(1)(a), R 336.1303)**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. The Permittee shall submit quarterly reports of fuel usage pursuant to Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by June 15 for the January 1 to March 31 reporting period, and by September 15 for the April 1 to June 30 reporting period, December 15 for the July 1 to September 30 reporting period, and March 15 for the October 1 to December 31 reporting period. (**R 336.1213(3)(c)(i))**

4. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1.SVPSG-91011S	55	195	**R 336.1201(3)**[1]

IX. OTHER REQUIREMENT(S)

1. The permittee shall carry out an Inspection and Maintenance Program for the No. 2A Package boiler, including keeping a log, to assure that the process equipment is maintained and operated in a satisfactory manner and in accordance with the Michigan Air Pollution Control Rules and existing law. **(R 336.1301, R 336.1331)**

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUPB3
EMISSION UNIT CONDITIONS

DESCRIPTION: The number 3 package boiler, rated at 136 million BTUs per hour, is fired by natural gas with No. 2 through No. 6 fuel oil back up. The boiler is also capable of incinerating noncondensible gases (NCGs) in compliance with 40 CFR 63 Subpart S.

POLLUTION CONTROL EQUIPMENT

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. SO_2	SO_2 emissions shall not exceed 1.67 pounds per million BTUs heat input[2]	Per 24 hour period	No. 3 boiler	Test Protocol	**R 336.1401**

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. No. 2 through No. 6 fuel oil	The maximum sulfur content of oil fired in the No. 3 boiler shall not exceed 1.5 %, based on a heating value of 18,000 BTUs per pound of oil[2]	N/A	No. 3 boiler	Test protocol	**R 336.1201(3)**

III. PROCESS/OPERATIONAL RESTRICTION(S) N/A

IV. DESIGN/EQUIPMENT PARAMETER(S) N/A

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Permittee shall conduct performance stack testing of one package boiler (Package Boiler # 2A, #3, or #4) to determine compliance with the NOx emission limitations within five years of issuance of this ROP. The package boiler tested and the test method shall be approved by the Department. **(R 336.1213(3), R 336.2001)**

2. Visible observations of the boiler emissions shall be conducted as specified in the Inspection and Maintenance Program. **(R 336.1301, R 336.1303)**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. On a monthly basis permittee shall record fuel usage rates and total SO_2 emissions. The SO_2 emissions may be calculated from the fuel usage. **(R 336.1201(3))**

2. Records shall be kept in accordance with the Inspection and Maintenance Program, specified in IX. The records shall include but not be limited to, records of inspections, problems identified, repairs and or corrective action taken, scheduled and completed maintenance, and records of visual observations to assure compliance with Rule 336.1301 and R 336.1901. **(R 336.1213(3), R 336.1301(1)(a), R 336.1303)**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. The Permittee shall submit quarterly reports of fuel usage pursuant to Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by June 15 for the January 1 to March 31 reporting period, and by September 15 for the April 1 to June 30 reporting period, December 15 for the July 1 to September 30 reporting period, and March 15 for the October 1 to December 31 reporting period. **(R 336.1213(3)(c)(i))**

4. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1.SVPSG-91011S	55	195	**R 336.1201(3)**[1]

IX. OTHER REQUIREMENT(S)

1. The permittee shall carry out an Inspection and Maintenance Program for the No. 3 Package boiler, including keeping a log, to assure that the process equipment is maintained and operated in a satisfactory manner and in accordance with the Michigan Air Pollution Control Rules and existing law. **(R 336.1301, R 336.1331)**

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUPB4
EMISSION UNIT CONDITIONS

DESCRIPTION: The number 4 package boiler, rated at 65 million BTUs per hour and 50,000 pounds of steam (at 250 psi.) per hour, is fired by natural gas. This boiler is also capable of incinerating noncondensible gases (NCGs) in compliance with 40 CFR 63 Subpart S.

POLLUTION CONTROL EQUIPMENT N/A

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NOx	a. NOx emissions when firing natural gas shall not exceed 0.14 lbs per million BTUs heat input	Per 24 hour average	No. 4 boiler	Approved method per R 336.2004, may be calculated based on fuel use	**R 336.1201(3)**
	b. Emissions shall not exceed 9.09 pounds	Per hour	No. 4 boiler	Approved method per R 336.2004, may be calculated based on fuel use	**R 336.1201(3)**

II. MATERIAL LIMIT(S) N/A

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Permittee shall not fire any fuel in the boiler other than sweet natural gas. **R 336.1201(1)**

IV. DESIGN/EQUIPMENT PARAMETER(S) N/A

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Permittee shall conduct performance stack testing of one package boiler (Package Boiler # 2A, #3, or #4) to determine compliance with the NOx emission limitations within five years of issuance of this ROP. The package boiler tested and the test method shall be approved by the Department. **(R 336.1213(3), R 336.2001)**

2. Visible observation of the boiler emissions shall be conducted as specified in the Inspection and Maintenance Program. **(R 336.1301, R 336.1303)**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

N/A

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The Permittee shall submit quarterly reports of fuel usage pursuant to Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by June 15 for the January 1 to March 31 reporting period, and by September 15 for the April 1 to June 30 reporting period, December 15 for the July 1 to September 30 reporting period, and March 15 for the October 1 to December 31 reporting period. **(R 336.1213(3)(c)(i))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1.SVPSG-91011S	55	195	**R 336.1201(3)**[1]

IX. OTHER REQUIREMENT(S)

1. The permittee shall carry out an Inspection and Maintenance Program for the No.4 Package boiler, including keeping a log, to assure that the process equipment is maintained and operated in a satisfactory manner and in accordance with the Michigan Air Pollution Control Rules and existing law. **(R 336.1301, R 336.1331)**

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

D. FLEXIBLE GROUP CONDITIONS

Part D outlines terms and conditions that apply to more than one emission unit. The permittee is subject to the special conditions for each flexible group in addition to the General Conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply, N/A (not applicable) has been used in the table. If there are no special conditions that apply to more than one emission unit, this section will be left blank.

E. NON-APPLICABLE REQUIREMENTS

At the time of the ROP issuance, the AQD has determined that no non-applicable requirements have been identified for incorporation into the permit shield provision set forth in the General Conditions in Part A pursuant to Rule 213(6)(a)(ii).

APPENDICES

Appendix 1: Abbreviations and Acronyms

The following is an alphabetical listing of abbreviations/acronyms that may be used in this permit.

AQD	Air Quality Division	MM	Million
acfm	Actual cubic feet per minute	MSDS	Material Safety Data Sheet
BACT	Best Available Control Technology	MW	Megawatts
BTU	British Thermal Unit	N/A	Not Applicable
°C	Degrees Celsius	NAAQS	National Ambient Air Quality Standards
CAA	Federal Clean Air Act	NESHAP	National Emission Standard for Hazardous Air Pollutants
CAM	Compliance Assurance Monitoring	NMOC	Non-methane Organic Compounds
CEM	Continuous Emission Monitoring	NOx	Oxides of Nitrogen
CFR	Code of Federal Regulations	NSPS	New Source Performance Standards
CO	Carbon Monoxide	NSR	New Source Review
COM	Continuous Opacity Monitoring	PM	Particulate Matter
department	Michigan Department of Environmental Quality	PM-10	Particulate Matter less than 10 microns in diameter
dscf	Dry standard cubic foot	pph	Pound per hour
dscm	Dry standard cubic meter	ppm	Parts per million
EPA	United States Environmental Protection Agency	ppmv	Parts per million by volume
EU	Emission Unit	ppmw	Parts per million by weight
°F	Degrees Fahrenheit	PS	Performance Specification
FG	Flexible Group	PSD	Prevention of Significant Deterioration
GACS	Gallon of Applied Coating Solids	psia	Pounds per square inch absolute
gr	Grains	psig	Pounds per square inch gauge
HAP	Hazardous Air Pollutant	PeTE	Permanent Total Enclosure
Hg	Mercury	PTI	Permit to Install
hr	Hour	RACT	Reasonable Available Control Technology
HP	Horsepower	ROP	Renewable Operating Permit
H_2S	Hydrogen Sulfide	SC	Special Condition
HVLP	High Volume Low Pressure *	scf	Standard cubic feet
ID	Identification (Number)	sec	Seconds
IRSL	Initial Risk Screening Level	SCR	Selective Catalytic Reduction
ITSL	Initial Threshold Screening Level	SO_2	Sulfur Dioxide
LAER	Lowest Achievable Emission Rate	SRN	State Registration Number
lb	Pound	TAC	Toxic Air Contaminant
m	Meter	Temp	Temperature
MACT	Maximum Achievable Control Technology	THC	Total Hydrocarbons
MAERS	Michigan Air Emissions Reporting System	tpy	Tons per year
MAP	Malfunction Abatement Plan	µg	Microgram
MDEQ	Michigan Department of Environmental Quality	VE	Visible Emissions
mg	Milligram	VOC	Volatile Organic Compounds
mm	Millimeter	yr	Year

*For HVLP applicators, the pressure measured at the gun air cap shall not exceed 10 pounds per square inch gauge (psig).

Appendix 2. Schedule of Compliance

The permittee certified in the ROP application that this stationary source is in compliance with all applicable requirements and the permittee shall continue to comply with all terms and conditions of this ROP. A Schedule of Compliance is not required. **(R 336.1213(4)(a), R 336.1119(a)(ii))**

Appendix 3. Monitoring Requirements

Specific monitoring requirement procedures, methods or specifications are detailed in Part A or the appropriate Source-Wide, Emission Unit and/or Flexible Group Special Conditions. Therefore, this appendix is not applicable.

Appendix 4. Recordkeeping

The permittee shall use the following approved formats and procedures for the recordkeeping requirements referenced in EURB1Number 1 Riley Boiler. Alternative formats must be approved by the AQD District Supervisor.

1. **<u>Coal Analysis</u>**

a) For each coal shipment received, the permittee shall obtain from the coal supplier a laboratory analysis of the ash content, sulfur content, and the BTU content. The determination of sulfur content shall be carried out in accordance with one of the following procedures: ASTM Method 3177-75 or ASTM Method 4239-85 or an alternative method approved by the AQD District Supervisor. For each coal shipment received, the permittee shall record the date received, source of coal and shipper, and tons received. These records shall be retained by the permittee for a minimum of five years, and made available to the Air Quality Division upon request.
b) At least once per calendar year, the permittee shall have an analysis performed of the coal ash content, sulfur content, and BTU content for one sample each of eastern coal and western coal. These analyses shall be independent of the analyses received from the coal supplier with each shipment. The determination of coal sulfur content shall be carried out in accordance with one of the following procedures: ASTM Method 3177-75 or ASTM Method 4239-85 or an alternative method approved by the AQD District Supervisor. These records shall be retained by the permittee for a minimum of five years, and made available to the Air Quality Division upon request.

Specific recordkeeping requirements, formats and procedures for the remaining emission units are detailed in Part A or the appropriate source-wide emission unit and/or flexible group special conditions.

Appendix 5. Testing Procedures

Specific testing requirement plans, procedures, and averaging times are detailed in the appropriate Source-Wide, Emission Unit and/or Flexible Group Special Conditions. Therefore, this appendix is not applicable.

Appendix 6. Permits to Install

The following table lists any PTIs issued since the effective date of previously issued ROP No 199600350.

Permit to Install Number	Description of Equipment	Corresponding Emission Unit(s) or Flexible Group(s)
N/A		

Appendix 7. Emission Calculations

Specific emission calculations to be used with monitoring, testing or recordkeeping data are detailed in the appropriate Source-Wide, Emission Unit and/or Flexible group Special Conditions. Therefore, this appendix is not applicable.

Appendix 8. Reporting

A. Annual, Semiannual, and Deviation Certification Reporting

The permittee shall use the MDEQ Report Certification form (EQP 5736) and MDEQ Deviation Report form (EQP 5737) for the annual, semiannual and deviation certification reporting referenced in the Reporting Section of the Source-Wide, Emission Unit and/or Flexible Group Special Conditions. Alternative formats must meet the provisions of Rule 213(4)(c) and Rule 213(3)(c)(i), respectively, and be approved by the AQD District Supervisor.

B. Other Reporting

Specific reporting requirement formats and procedures are detailed in Part A or the appropriate Source-Wide, Emission Unit and/or Flexible Group Special Conditions. Therefore, Part B of this appendix is not applicable.