BART DETERMINATION
SUPPORT DOCUMENT FOR
PORT TOWNSEND PAPER CORPORATION
PORT TOWNSEND, WASHINGTON

Prepared by

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EXECUTIVE SUMMARY

The Best Available Retrofit Technology (BART) program is part of the larger effort under the federal Clean Air Act Amendments of 1977 (CAA) to eliminate human-caused visibility impairment in all mandatory federal Class I areas. Sources that are required to comply with the BART requirements are those sources that:

1. Fall within 26 specified industrial source categories.
2. Commenced operation or completed permitting between August 7, 1962 and August 7, 1977.
3. Have the potential to emit more than 250 tons per year of one or more visibility impairing compounds.
4. Cause or contribute to visibility impairment within at least one mandatory federal Class I area.

The Port Townsend Paper Corporation (PTPC) operates a kraft pulp and paper mill that manufacturers unbleached kraft pulp, kraft papers, and lightweight linerboard. The mill is located in Port Townsend, Washington. The mill produces emissions of particulate matter (PM), sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NO_X), and hydrocarbons. The pollutants considered to be visibility impairing are PM, SO_2, and NO_X.

Kraft pulp mills such as the PTPC facility are one of the 26 listed BART source categories. The PTPC mill was first constructed in the late 1920s, but it has had many modifications since then. The mill's potential emissions exceed 250 tons per year (tpy) for at least one of NO_X, SO_2, or PM_{10}. Four units are BART-eligible by construction date. They are the Recovery Furnace, Smelt Dissolving Tank, No. 10 Power Boiler, and the Lime Kiln.

Modeling of visibility impairment was done following the Oregon/Idaho/Washington/EPA-Region 10 BART modeling protocol.[1] Modeled visibility impacts of baseline emissions show impacts on the 8th highest day in any year (the 98th percentile value) of greater than 0.5 deciviews (dv) at only one Class 1 area, the Olympic National Park. The visibility impairment of the highest 98th percentile day was 1.50 dv. NO_X and SO_2 emissions from the Recovery Furnace and No. 10 Power Boiler were responsible for most of the visibility impact.

PTPC prepared a BART technical analysis using Washington State's BART Guidance.[2]

The Washington State Department of Ecology (Ecology) determined that the current level of emissions control is BART for the four applicable units. A wide variety of additional controls were investigated for each unit, but all were determined to be either technically or economically infeasible.

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[1] Modeling protocol available at **http://www.deq.state.or.us/aq/haze/docs/bartprotocol.pdf**.
[2] "Best Available Retrofit Technology Determinations Under the Federal Regional Haze Rule," Washington State Department of Ecology, June 12, 2007.

1. INTRODUCTION

1.1 The BART Program and Analysis Process

The federal Clean Air Act Amendments of 1977 (CAA) established a national goal of eliminating man-made visibility impairment in all mandatory federal Class I areas. The CAA requires certain sources to utilize Best Available Retrofit Technology (BART) to reduce visibility impairment as part of the overall plan to achieve that goal.

Requirements for the BART program and analysis process are given in 40 CFR 51, Subpart P and Appendix Y to Part 51.[3] Sources are required to comply with the BART requirements if they:

1. Fall within 26 specified industrial source categories.
2. Commenced operation or completed permitting between August 7, 1962 and August 7, 1977.
3. Have the potential to emit more than 250 tons per year of one or more visibility impairing compounds including sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM), and volatile organic compounds (VOCs).

Emission units that meet the source category, age, and potential to emit criteria must also make the facility "cause or contribute" to visibility impairment within at least one mandatory federal Class I area for the facility to remain BART applicable. Ecology has adopted the "cause and contribute" criteria that EPA suggested in its guideline. BART-eligible units at a source cause visibility impairment if their modeled visibility impairment is at least 1.0 deciview (dv). Similarly, the criterion for contributing to impairment means that the source has a modeled visibility impact of 0.5 dv or more.

The BART analysis protocol in Appendix Y Sections III–V uses a 5-step analysis to determine BART for SO_2, NO_X, and PM. The five steps are:

Step 1 – Identify all available retrofit control technologies.
Step 2 – Eliminate technically infeasible control technologies.
Step 3 – Evaluate the control effectiveness of remaining control technologies.
Step 4 – Evaluate impacts and document the results.
Step 5 – Evaluate visibility impacts.

Ecology requires an applicable facility to prepare a BART technical analysis report and submit it to Ecology. Ecology then evaluates the report and makes a final BART determination decision. This decision is issued to the source owner as an enforceable Order, and included in the State's Regional Haze State Implementation Plan (SIP).

[3] Appendix Y to 40 CFR 51–Guidelines for BART Determinations Under the Regional Haze Rule.

As allowed by the EPA BART guidance, Ecology has chosen to consider all 5 factors in its BART determinations. To be selected as BART, a control has to be available, technically feasible, cost effective, provide a visibility benefit, and have a minimal potential for adverse non-air quality impacts. Normally the potential visibility improvement from a particular control technology is only one of the factors weighed for determining whether a control constitutes BART. However, if two available and feasible controls are essentially equivalent in cost-effectiveness and non-air quality impacts, visibility improvement becomes the deciding factor for the determination of BART.

1.2 The Port Townsend Paper Corporation Mill

The Port Townsend Paper Corporation (PTPC) operates a kraft pulp and paper mill (PTPC Mill) in Port Townsend, Washington. It is located in the northeast corner of the Olympic peninsula where Puget Sound meets the Strait of Juan de Fuca. The facility produces a variety of unbleached pulp and paper products including market pulp, converting paper, and containerboard. It was originally constructed in 1927. The PTPC Mill is a Title V source operating under Air Operating Permit WA 000092-2. Kraft mills are one of the 26 BART-eligible source categories. The Washington State Department of Ecology (Ecology) received a BART Analysis and Determination Report from PTPC on December 20, 2007.

1.3 BART-Eligible Units at the PTPC Mill

A review of the PTPC Mill emission sources found that:

1. Four of the plant's individual emission units were BART-eligible by construction date. The four are the Recovery Furnace, the Smelt Dissolving Tank, the No. 10 Power Boiler, and the Lime Kiln.
2. The four individual emission units in total have a combined potential to emit at least 250 tpy of nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM).

A Class I area visibility impact analysis was performed using the maximum daily emissions during the 2003-2005 time period and the CALPUFF model. Model results indicate visibility impacts from the BART-eligible units exceeded the 0.5 deciview (dv) contribution threshold in at least one Class I area. This confirmed that PTPC was required to continue in the BART process and prepare a BART determination.

1.3.1 Existing Recovery Furnace Emissions Control

PTPC operates a non-direct contact evaporator (NDCE) Recovery Furnace with an electrostatic precipitator (ESP). The Recovery Furnace fires predominantly black liquor solids (BLS) and some recycled fuel oil (RFO).

A chemical recovery furnace is not simply a "boiler" designed to burn fuel and produce steam. It is a complex device which serves as a chemical reactor, a chemical recovery unit, an internal high efficiency SO_2 scrubber, and an energy recovery unit. The Recovery Furnace recovers

sufficient energy to supply a major portion of the PTCP Mill's steam load and electrical power needs. The Recovery Furnace operates by spraying spent pulping chemical liquids (black liquor) from the digester into the furnace. The organic chemicals in the black liquor (mostly lignins) are combusted. Combustion provides the energy to recover the inorganic pulping chemicals (reduce sodium sulfate to sodium sulfide) for reuse.

The major pollutants emitted from the Recovery Furnace are SO_2, NO_X, and PM_{10}. SO_2 comes from the oxidation of organic sulfur compounds known as total reduced sulfur (TRS) present in the black liquor and losses of sulfur from the chemical recovery section of the furnace. Additional SO_2 emissions result from the oxidation of sulfur in fuel oil which may be used during the combustion process. The chemical recovery process scrubs out most of the SO_2 generated in the chemical recovery/combustion process in the furnace. The scrubbing action is through the reaction of sodium oxide with the SO_2. SO_2 emissions from the furnace represent a loss of process chemical and are not desirable, so the furnace operation is optimized to minimize sulfur loss.

NO_X may form as fuel NO_X and thermal NO_X. Technical literature suggests that NO_X formation from the chemical recovery process is primarily fuel NO_X since recovery furnace temperatures are not high enough for significant thermal NO_X formation.[4] NO_X emissions from recovery furnaces are typically low due to the low nitrogen (N) concentration in the black liquor solids (approximately 0.1 percent), the low overall conversion of liquor N to NO_X (10-25 percent), and the existence of sodium fumes that can participate in "in-furnace" NO_X reduction or removal.[5]

The majority of PM_{10} emissions from the Recovery Furnace are sodium salts with about 80 percent of the PM_{10} being sodium sulfate and smaller amounts of potassium sulfate, sodium carbonate, and sodium chloride.[6] These salts primarily result from the carryover of solids from the combustion process plus sublimation and condensation of inorganic chemicals.[7] Some PM_{10} emissions can also be attributed to the combustion of fossil fuel. Filterable PM_{10} emissions from recycled fuel oil combustion depend not only on the completeness of combustion but also on the sulfur and metals content of the oil.

The particulate collected by the ESP is sent to the Smelt Dissolving Tank for chemical recovery.

The most restrictive emission limits that the Recovery Furnace is currently subject to are in 40 CFR 63 Subpart MM and PSD 1. The applicable PM, NO_X, and SO_2 emission limits are shown in Table 1-1.

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[4] NCASI Special Report 99-01, *A Review of NO_X Emission Control Strategies for Industrial Boilers, Kraft Recovery Furnaces, and Lime Kilns,* April 1999.
[5] NCASI Special Report No. 03-06, *Effect of Kraft Recovery Furnace Operations on NOX Emissions: Literature Review and Summary of Industry Experience,* October 2003.
[6] NCASI Technical Bulletin No. 725, *Particulate Matter Emissions From Kraft Mill Recovery Furnaces, Lime Kilns, and Smelt Dissolving Tanks,* November 1996.
[7] AP-42, Section 10.2, Chemical Wood Pulping, dated September 1990.

Table 1-1. RECOVERY FURNACE CURRENT EMISSION LIMITS

Pollutant	Emission Limit	Regulatory Basis
PM/PM_{10}[a]	0.044 gr/dscf @ 8% O_2	NESHAP Subpart MM, 40 CFR 63.862(a)(1)(i)(A)
NO_X[b]	N/A	N/A
SO_2[c]	200 ppm @ 8% O_2	Permit Limit PSD-I (Condition 2)

[a] PM limits of 0.08 gr/dscf and 0.10 gr/dscf both at 8% O_2 also apply to the Recovery Furnace per Order DE 05AQIS-2892 and WAC 173-405-040(1)(a), respectively. Since the MACT limit of 0.044 gr/dscf at 8% O_2 is also applicable, only the most stringent standard is presented in the table.
[b] There are no NO_X limits that apply to PTPC's Recovery Furnace.
[c] An SO_2 limit of 500 ppm at 8% O_2 also applies to the Recovery Furnace per WAC 173-405-040(11)(a). Since the 200 ppm at 8% O_2 from the PSD-I permit limit is on the same basis, the more stringent of the two limits is presented in the table.

The PTPC Mill's Recovery Furnace is equipped with three electrostatic precipitators (ESPs) to reduce PM/PM_{10}. Each ESP is a parallel single chamber, dry bottom ESP. Two of the ESP units, manufactured by Research Cottrell, were rebuilt in 1993. The third ESP, manufactured by Environmental Elements, was installed as part of a Prevention of Significant Deterioration (PSD) permitting effort in approximately 1986 to 1987. No other add-on control devices are used for the Recovery Furnace.

1.3.2 Existing Smelt Dissolving Tank Emissions Control

A smelt dissolving tank is a part of the kraft pulping chemical recovery process. Smelt, the molten chemicals collected in the bottom of a recovery furnace, is continuously withdrawn from the furnace into a smelt dissolving tank. The smelt is then dissolved with weak wash[8] in the Smelt Dissolving Tank to produce green liquor, which is processed in the causticizing area to produce white liquor for use in the chip digestion process.[9] PM emissions are primarily composed of inorganic components such as sodium sulfate and sodium carbonate. NO_X emissions are minimal since no combustion occurs in these units. SO_2 emissions are from the oxidation of Total Reduced Sulfur (TRS) in the smelt.

The most restrictive emission limitation for the Smelt Dissolving Tank is in 40 CFR 63 Subpart MM. The applicable PM, NO_X, and SO_2 emission limits are shown in Table 1-2.

[8] This process water, also known as weak white liquor, is composed of all liquors used to wash lime mud and green liquor precipitates.
[9] The names of the various liquors denote their actual color.

Table 1-2. SMELT DISSOLVING TANK CURRENT EMISSION LIMITS

Pollutant	Emission Limit	Regulatory Basis
PM/PM_{10}[a]	0.20 lb/ton BLS	NESHAP Subpart MM, 40 CFR 63.862(a)(1)(i)(b)
NO_X[b]	N/A	N/A
SO_2[c]	N/A	N/A

[a] A PM limit of 0.3 lb/ton BLS also applies to the Smelt Dissolving Tank per WAC 173-405-040(2). Since the MACT limit of 0.20 lb/ton BLS is also applicable, only the most stringent standard is presented in the table.
[b] There are no NO_X limits that apply to PTPC's Smelt Dissolving Tank.
[c] There are no SO_2 limits that apply to PTPC's Smelt Dissolving Tank.

The Smelt Dissolving Tank is controlled with a Ducon UW4 Model 4 scrubber. The scrubber was originally installed during the 1970s and was modified by APTech in 2003. The modification in 2003 included the installation of new spray header and nozzles, spin breakers, and chevrons in order to further reduce particulate matter emissions and allow for compliance with MACT II requirements. No other control devices are used on the Smelt Dissolving Tank.

1.3.3 Existing No. 10 Power Boiler Emissions Control

The No. 10 Power Boiler operates by combusting wood waste, primary clarifier sludge, old corrugated container (OCC) rejects, and recycled fuel oil (RFO) to produce steam for use in the kraft pulping process. The boiler is a spreader stoker-type boiler with horizontally opposed overfire air ports and tangential oil burners downstream (above) the grate. While it primarily fires wood waste on the grates, the RFO fired at the tangential burners contributes approximately 30 percent of the heat input.

PM_{10} emissions from wood-fired boilers result from inorganic materials contained in the wood waste and unburned carbon resulting from incomplete combustion.[10] NO_X emissions from boilers are formed by two mechanisms, fuel NO_X and thermal NO_X. Fuel NO_X is the dominant mechanism for NO_X formation during wood waste combustion.[11] SO_2 emissions from combination wood residue and oil boilers are formed as the sulfur contained in the oil oxidizes during the combustion process. PTPC's RFO contains 0.45 to 0.75 percent sulfur, approximately 30 percent[12] of which oxidizes and exits the stack as SO_2. The remaining sulfur is captured by the alkaline wood ash and minimal amounts may exhaust as other sulfur compounds.[13]

[10] NCASI Technical Bulletin No. 884, *Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers,* August 2004.
[11] NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NOx, SO_2 and PM Emissions*, June 2006.
[12] Average percentage of the sulfur burned that is emitted as SO_2, calculated based on the correlation for sulfur capture in combination bark boilers developed by NCASI. NCASI Technical Bulletin No. 884, *Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers,* August 2004, pp. 40 and 41.
[13] NCASI Technical Bulletin No. 884, *Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers*, August 2004.

The most restrictive emission limitations on emissions from the No. 10 Power Boiler are in 40 CFR 60 Subpart D NSPS. The applicable PM, NO_X, and SO_2 emission limits are shown in Table 1-3.

Table 1-3. NO. 10 POWER BOILER'S CURRENT EMISSION LIMITS

Pollutant	Emission Limit	Regulatory Basis
PM/PM_{10}	0.10 lb/MMBtu	NSPS Subpart D, 40 CFR 60.42(a)(1)
NO_X	0.30 lb/MMBtu	NSPS Subpart D, 40 CFR 60.44(2)
SO_2	0.80 lb/MMBtu	NSPS Subpart D, 40 CFR 60.43(a)(1)
Note: NESHAP Subpart DDDDD, Boiler MACT, limits may have applied to the No. 10 Power Boiler. However, the Boiler MACT rule was vacated by the United States Court of Appeals decision on June 8, 2007.		

The No. 10 Power Boiler employs multiclones followed by a Turbotak scrubber to control particulate matter emissions. The multiclones remove the coarse particulate using centrifugal action. The Turbotak was installed in 1988 as a replacement of an existing venturi scrubber. The Turbotak scrubber is a wet scrubber that exposes the exhaust gas stream to a series of atomized water sprays. The multiple water sprays allow for optimizing the ratio between the water droplet diameter and the particulate matter diameter. The Turbotak also employs removal equipment including a knockout chamber, a fan, and chevrons.

1.3.4 Existing Lime Kiln Emissions Control

In the PTPC Mill's Lime Kiln, calcium oxide (CaO) is regenerated from lime mud, which consists primarily of calcium carbonate ($CaCO_3$). The heat required to convert the calcium carbonate to calcium oxide is provided by the combustion of RFO. Lime kilns are generally long, rotating cylindrical units installed on a slope (one end of the lime kiln is at a higher elevation than the other). Lime mud enters the kiln at the "higher" end and makes its way down to the "lower" end of the kiln. The heat, provided by the fuel oil burner, is generated at the "lower" end of the kiln. This counter-current flow of lime mud and hot combustion gases provides an efficient environment for the conversion to CaO.

PM/PM_{10} emissions from lime kilns primarily result from combustion gases picking up dust from lime mud and other particulate matter from alkali vaporization. Sodium sulfate and sodium carbonate primarily comprise the smaller PM with aerodynamic diameter less than 10 µm. NO_X formation in PTPC Mill's Lime Kiln occurs as both "thermal NO_X" and "fuel NO_X." The kiln reaches temperatures high enough for the direct oxidation of atmospheric nitrogen to NO_X. Thermal NO_X formation increases with temperature, oxygen and nitrogen concentrations, and residence time. Additionally, the nitrogen in the fuel oil fired by the Lime Kiln can convert to NO, forming "fuel NO_X." SO_2 emissions from PTPC Mill's Lime Kiln results from the oxidation of sulfur in the fuel oil and, to a lesser extent, sulfur in the lime mud. While the potential for SO_2 emissions from some lime kilns may be high based on the sulfur content of the fuel, most lime kilns emit very low levels of SO_2 due to the regenerated quicklime in the kiln acting as an inherent scrubbing agent. PTPC's particulate control venturi scrubber following the

kiln further augments this SO_2 removal process since the scrubbing solution becomes alkaline as it captures the lime dust.[14]

The most restrictive emission limitations on the Lime Kiln are in 40 CFR 63 Subpart MM and WAC 173-400-040(11)(a). The applicable PM, NO_X, and SO_2 emission limits are shown in Table 1-4.

Table 1-4. LIME KILN CURRENT EMISSION LIMITS

Pollutant	Emission Limit	Regulatory Basis
PM/PM_{10}[a]	0.064 gr/dscf @ 10% O_2	NESHAP Subpart MM, 40 CFR 63.862(a)(1)(i)(c)
NO_X[b]	N/A	N/A
SO_2[c]	500 ppm @ 10% O_2	WAC 173-405-040(11)(a)

[a] A PM limit of 0.13 gr/dscf at 10% O_2 also applies to the Lime Kiln per WAC 173-405-040(3)(a). Since the MACT limit of 0.064 gr/dscf @ 10% O_2 is also applicable, only the most stringent standard is presented in the table.
[b] There are no NO_X limits that apply to PTPC's Lime Kiln.
[c] A TRS limit of 8 ppm at 10% O_2 also applies to the Lime Kiln per 40 CFR 60.283 (a)(5).

The Lime Kiln employs a venturi scrubber to control particulate matter emissions. The showers of the Lime Kiln's venturi scrubber were modified in 2003 for MACT II compliance. No other control devices are used for the Lime Kiln.

1.4 Visibility Impact of the PTPC Mill's BART-Eligible Units

Class I area visibility impairment and improvement modeling was performed by PTPC using the BART modeling protocol developed by Oregon, Idaho, Washington, and EPA Region 10.[15] This protocol uses three years of metrological information to evaluate visibility impacts. As directed in the protocol, PTPC used the highest 24-hour emission rates that occurred in the 3-year period to model its impacts on Class I areas. The modeling indicates that the emissions from this plant caused visibility impairment to Olympic National Park on both the 8th highest impacted day in any one year and the 22nd highest day over the three years that were modeled.[16] For more information on visibility impacts of this facility, see Section 3.

[14] Ibid.
[15] A copy of the modeling protocol is available at **http://www.deq.state.or.us/aq/haze/docs/bartprotocol.pdf**.
[16] A source causes visibility impairment if its modeled visibility impact is above one deciview, and contributes to visibility impairment if its modeled visibility impact is above 0.5 deciview.

2. BART TECHNOLOGY ANALYSIS

The PTPC BART technology analysis was based on the 5-step process defined in BART guidance and listed in Section 1.1 of this report.

The following three tables identify and summarize possible control options considered in the BART determination analysis for PM_{10}, NO_X, and SO_2 emissions from the PTPC Mill. Sections 2.1 through 2.4 discuss emissions from each BART emissions unit. A more complete description of each control option is provided in Appendix A. Longer discussions of why technologies were considered infeasible were placed in Appendices B through E to make the main body of this report shorter.

Table 2-1. PM_{10} CONTROL TECHNOLOGIES EVALUATED

Control Technology	Available for Emission Unit (Yes/No)[a,b]			
	NDCE Recovery Furnace	Smelt Dissolving Tank	No. 10 Power Boiler	Lime Kiln
Fabric Filters (baghouse)	N/A	N/A	YES	N/A
Cyclone Separator	N/A	N/A	YES	N/A
Wet Scrubber	N/A	Currently used	Currently used	N/A
ESP	Currently used	N/A	YES	N/A
Proper Operating Practices	N/A	N/A	YES	N/A

[a] Availability based on whether control technology can be considered for each.

[b] Availability of PM_{10} control on all units except the No. 10 Power Boiler is not applicable (N/A) because the remaining units comply with MACT standards for PM. Per Section IV of EPA's "Guidelines for BART Determinations under the Regional Haze Rules" [40 CFR Part 51, Appendix Y], "Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, [state agencies] may rely on the MACT standards for purposes of BART."

Table 2-2. NO_X CONTROL TECHNOLOGIES EVALUATED

Control Technology	Available for Emission Unit (Yes/No)[a]			
	NDCE Recovery Furnace	Smelt Dissolving Tank[b]	No. 10 Power Boiler	Lime Kiln
Low Excess Air (LEA)	Yes	N/A	Yes	No
Staged Combustion	Currently used	N/A	Currently used	Yes
Flue Gas Recirculation (FGR)	Yes	N/A	Yes	Yes
Low NO_X Burners (LNB)	Yes	N/A	Yes	Yes
Fuel Staging/Reburning	Yes	N/A	Yes	Yes
Water/Steam Injection	No	N/A	No	Yes
Mid-Kiln Firing	No	N/A	No	Yes
Mixing Air Fan	No	N/A	No	Yes
Good Operating Practices and Proper Design	Yes	N/A	Yes	Yes
Selective Non-Catalytic Reduction (SNCR)	Yes	N/A	Yes	Yes
Selective Catalytic Reduction (SCR)	Yes	N/A	Yes	Yes
Oxidation/Reduction Scrubbing	Yes	N/A	Yes	Yes

[a] Availability based on whether control technology can be considered for each emission unit, not on technical feasibility.

[b] NO_X control technologies are not evaluated for the Smelt Dissolving Tank since this unit is not a source of NO_X emissions.

Table 2-3. SO_2 CONTROL TECHNOLOGIES EVALUATED

Control Technology	Available for Emission Unit (Yes/No)[a]			
	NDCE Recovery Furnace	Smelt Dissolving Tank	No. 10 Power Boiler	Lime Kiln
Flue Gas Desulfurization (FGD) with Wet Scrubber	Yes	Yes[b]	Yes	Yes
FGD – Semi-Dry Lime Hydrate Slurry Injection (semi-dry slurry injection) with ESP or Baghouse	Yes	Yes[b]	Yes	Yes
FGD – Semi-Dry Lime Hydrate Powder Injection (semi-dry powder injection) with ESP or Baghouse	Yes	Yes[b]	Yes	Yes
FGD – Spray Drying with ESP or Baghouse	Yes	Yes[b]	Yes	Yes
Inherent Dry Scrubbing	Currently used	No	No	Currently used
Low Sulfur Fuel Selection	Yes	No	Yes	Yes
Increased Oxygen Levels at the Burners	No	No	No	Yes
Good Operating Practices	Yes	Yes	Currently used	Yes

[a] Availability based on whether control technology can be considered for each emission unit, not on technical feasibility.
[b] Ecology recognizes that the Smelt Dissolving Tank vent system has very little flow, so emission control using these technologies is questionable. PTPC chose to evaluate them, so those evaluations are presented in this report.

2.1 NDCE Recovery Furnace Control Options

2.1.1 PM/PM_{10} Control Options

As noted in Section 1.3, the Recovery Furnace is subject to the NESHAP (MACT) standard for PM (as a surrogate for HAP metals) contained in 40 CFR Part 63 Subpart MM, *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills.*

Particulate emissions from the Recovery Furnace are controlled by an ESP. The ESP control on the Recovery Furnace reduces particulate emissions to less than the MACT limit of 0.044 gr/dscf at eight percent O_2. Actual emissions average about 50 percent of the MACT standard.

The date the PTCP Mill was required to comply with the particulate emission requirements of 40 CFR Part 63 Subpart MM by March 13, 2004. They met that standard without the need to add

any new particulate controls. No new technologies for controlling PM have subsequently become available after this date. Therefore, PTPC proposed the current dry ESP and meeting the MACT limits for PM/PM_{10} for the Recovery Furnace as BART and did not analyze other options for PM emissions control from the Recovery Furnace.[17]

2.1.2 NO_X Control Options

Recovery furnaces inherently use staged combustion. The design of the kraft Recovery Furnace at the PTPC Mill uses multiple levels of air admission into the furnace to control the kraft recovery sodium sulfate reactions and to assure complete combustion of organic compounds. The process control system that regulates this staged combustion process helps minimize the formation of NO_X.

Recovery furnaces have special safety systems to preclude fuel/air explosions and steam explosions if steam pressure ratings are exceeded. Chemical recovery furnaces can experience other unique types of explosions such as pyrolysis gas (CO, methane, hydrogen, and others) explosions and smelt/water explosions. If a recovery furnace experiences a "black out" where the flame extinguishes and the hot char bed continues to produce pyrolysis gases, then a spark or flame can reignite the gases and produce a fuel/air explosion. If a boiler tube develops a leak and water comes into contact with the molten salt at the bottom of the furnace, a very forceful explosion may take place. These hazards pose a significant danger to employees and equipment. These special safety issues and the chemical reactions noted in Section 1.3.1 are what make a chemical recovery furnace unique and explain why some emission technologies that may work for ordinary boilers are technically infeasible and even dangerous for a chemical recovery furnace.

In a 2003 special report, the National Council for Air and Stream Improvement (NCASI) specifically addressed options for reducing NO_X emissions from recovery furnaces, indicating that no operating kraft recovery furnace currently utilizes post-combustion control (such as SCR or SNCR) and limited pollution prevention techniques for NO_X are available.[18] A subsequent NCASI Corporate Correspondence Memorandum states:[19]

> *Optimization of the staged combustion principle within large, existing kraft recovery furnaces to achieve lower NO_X emissions might be the only technologically feasible option at the present time for NO_X reduction . . . Ultimately, the liquor nitrogen content, which is dependent on the types of wood pulped, is the dominant factor affecting the level of NO_X emissions*

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[17] Per Section IV of EPA's "*Guidelines for BART Determinations under the Regional Haze Rules*" [40 CFR Part 51, Appendix Y], "Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, [state agencies] may rely on the MACT standards for purposes of BART."

[18] NCASI Special Report No. 03-06, *Effect of Kraft Recovery Furnace Operations on NOx Emissions: Literature Review and Summary of Industry Experience,* October 2003.

[19] NCASI Corporate Correspondent Memorandum No. 06-014, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NOx, SO_2 and PM Emissions*, June 2006.

from black liquor combustion in a recovery furnace. Unfortunately, this factor is beyond the control of pulp mill operators.

NO_X control technologies determined to be technically infeasible are discussed in Appendix B.

As described in the NCASI publication quoted above, and as found in a search of the EPA RBLC database, good combustion practices optimizing the staged combustion inherent in the design of a kraft recovery furnace is the only NO_X control that is both available technology and has been installed on recovery furnaces in the U.S.

2.1.3 SO_2 Control Options

The following table and the following text describe possible SO_2 control options and why PTPC proposed them to be either technically or economically infeasible for the Recovery Furnace.

Table 2-4. TECHNICALLY INFEASIBLE RECOVERY FURNACE SO_2 CONTROL OPTIONS

Technology	Description
FGD with Wet Scrubber	NCASI reports that the use of add-on control equipment specifically installed to reduce of SO_2 from recovery furnaces has not been demonstrated anywhere in the United States and is considered prohibitive from a cost perspective.[20] There are several reasons that a wet scrubber has not been applied for the control of SO_2 from a kraft recovery furnace. A well designed and properly operated recovery furnace emits little SO_2 during normal operation. The majority of SO_2 emissions occur during highly sporadic, unpredictable, and short duration "spikes" in SO_2 emissions. These spikes can be theoretically traced back to dozens of potential culprits, the best characterized and understood of which is variations in black liquor sulfidity and solids content. Thus, a scrubber would not actually remove much SO_2 on an annual basis. Based on the technical difficulties described and the lack of successful implementation, PTPC has also proposed that this technology be considered technically infeasible for control of SO_2 and was not considered further.
FGD – Semi-Dry Slurry or Powder Injection or Spray Drying with ESP or Baghouse	The spray dryer system operation is based on the injection of a sorbent such as lime or sodium bicarbonate into the flue gas. For a kraft recovery furnace, such injection is not reasonable. Dust captured by the ESP is returned to the kraft recovery process via the Smelt Dissolving Tank. Introduction of lime or sodium bicarbonate into the

[20] NCASI, *Corporate Correspondence Memo CC-06-14: Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NOx, SO2, and PM Emissions*, June 4, 2006.

Technology	Description
	flue gas will disrupt the chemical balance of the kraft process. Also, as with wet FGD systems, there is a lack of existing installations for this process. The sulfur content of the gas stream is too low for effective operation of the control technology. For these reasons, PTPC proposed that this technology be considered technically infeasible and eliminated from BART consideration.
Low Sulfur Fuel Selection	The fuel of a recovery furnace is primarily the black liquor processed by the furnace, supplemented with fuel oil. The furnace is operated as a high efficiency SO_2 scrubber in order to recover process chemicals. The sulfur content of the black liquor solids cannot be controlled by the PTPC Mill, but is efficiently recovered by proper operation of the Recovery Furnace. SO_2 emissions primarily come from supplemental fuel. At the PTPC Mill, RFO is the fuel oil used plantwide. It has sulfur content typically between 0.45 and 0.75% sulfur, with a guaranteed maximum of 0.76%. As discussed in Section 2.3.3, switching to the next lower sulfur content of RFO would cost $15,702 per ton of SO_2 emissions avoided. PTPC proposed that this is not cost effective for BART. For these reasons, PTPC did not consider low-sulfur fuel selection any further for the Recovery Furnace.

2.1.4 PTPC's BART Proposal for the Recovery Furnace

For PM/PM_{10} control, PTPC proposed to continue to use the existing ESP as BART. Actual emissions from use of the current ESP average less than 50 percent of the NESHAP Subpart MM limit of 0.044 gr/dscf at eight percent O_2.

For NO_X control, PTPC proposed to continue to properly operate the existing staged combustion system as BART for control of NO_X emissions from the Recovery Furnace.

For SO_2 control, PTPC proposed that Good Operating Practices, as currently in place, should be determined to be BART for the Recovery Furnace. Good Operating Practices entail minimizing fuel oil firing and maintaining the char bed resulting from black liquor solids combustion.

2.2 Smelt Dissolving Tank Control Options

As discussed in Section 1.3.2, a wet scrubber is currently used to reduce PM/PM_{10} emissions. This wet scrubber also provides some reduction of sulfur emissions. The Smelt Dissolving Tank is not a combustion source and has very low emissions as shown in Table 3-3 in Section 3.

2.2.1 PM/PM_{10} Control Options

As noted in Section 1.3, the Smelt Dissolving Tank is subject to the NESHAP (MACT) standard for PM (as a surrogate for HAP metals) contained in 40 CFR Part 63 Subpart MM, *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills.* The date the PTPC Mill was to be in compliance with the requirements of 40 CFR Part 63 Subpart MM was March 13, 2004. No new technologies for controlling smelt dissolving tank PM have subsequently become available after this date. As a result, no additional engineering analyses were conducted by PTPC.

2.2.2 NO_X Control Options

NO_X control technologies are not evaluated for the Smelt Dissolving Tank. It is not a combustion source and the materials processed are not a source of NO_X.

2.2.3 SO_2 Control Options

A possible alternative SO_2 control (to the currently used wet scrubber) might be FGD using either a semi-dry or dry process with addition of either an ESP or baghouse. Operation of either of these spray-dryer-type systems is based on the feasibility of injecting lime into the flue gas followed by a dry ESP or baghouse downstream of the dryer to capture the dry particles. The Smelt Dissolving Tank's exhaust stream has high moisture content (typically 25 to 40 percent) and almost no flowrate, making usage of a spray dryer with a dry ESP system technically infeasible.[21]

The addition of an alkaline solution to the existing wet scrubber could theoretically provide as much as 90 percent reduction of potential annual SO_2 emissions. The annual cost effectiveness for implementing this control technology on the low airflow and low emissions from the Smelt Dissolving Tank was estimated to be $16,247 per ton of SO_2 removed to remove 1.03 tons per year. PTPC proposed that the option of reducing SO_2 emissions by adding alkaline solution to the existing scrubber be considered economically infeasible.

2.2.4 PTPC's BART Proposal for the Smelt Dissolving Tank

For PM/PM_{10} control, PTPC proposes to continue to use the Smelt Dissolving Tank's existing scrubber in lieu of additional add-on control or replacement of the existing scrubber. PTPC will continue to operate the existing scrubber to comply with the existing NESHAP (MACT) Subpart MM limit of 0.20 lb PM_{10} per ton BLS.

For NO_X control, PTPC proposes no additional controls as BART. There is no combustion occurring in the Smelt Dissolving Tank, and the unit is not considered a source of NO_X emissions.

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[21] Ibid.

For SO_2 control, PTPC proposes to continue to properly operate the Smelt Dissolving Tank's existing wet scrubber as BART.

2.3 No. 10 Power Boiler Control Options

As discussed in Section 1.3.3, the No. 10 Power Boiler has an overfire air system. A multiclone followed by a wet scrubber are currently used to reduce PM/PM10 emissions.

2.3.1 PM/PM_{10} Control Options

Table 2-1 and Appendix A list five identified PM/PM_{10} control technologies along with proper operating practices. Since the power boiler currently uses a multiclone and wet scrubber, only the two alternative PM control technologies, discussed in the following table, were investigated further.

Table 2-5. NO. 10 POWER BOILER PM/PM_{10} CONTROL OPTIONS EVALUATED

Technology	Description
Fabric Filters (baghouse)	The use of fabric filters to control particulate matter emissions from wood-fired boilers results in a fire hazard due to the potential of burning cinders escaping the multiclone, temperature excursions, and/or operating upsets combined with fabric flammability causing the fabric filters to ignite or melt, depending on the fabric used. Because of this, fabric filters are rarely used on wood-fired boilers. Fabric filters have been successfully used on some wood-fired boilers that burn wood residue or bark stored in salt water because the salt reduces the fire hazard. PTPC's Title V Operating Permit specifically prohibits burning salty hog fuel in the No. 10 Power Boiler as part of the opacity limit. The use of fabric filters to control particulate matter emissions from the No. 10 Power Boiler is proposed to be technically infeasible due to fire hazard.
Wet ESP (addition)	Addition of a wet ESP following the existing scrubber and multiclone system was considered technically feasible. A cost control evaluation was done to evaluate economic feasibility. The control level for the addition of a wet ESP was based on a vendor guarantee of 0.01 gr/dscf. This guarantee represents a removal efficiency of approximately 69% based on the current limit of 0.10 lb/MMBtu at maximum capacity.[22] The cost per ton of PM_{10} removed for the installation of a wet ESP to further control the No. 10 Power Boiler was estimated to be $11,294. PTPC proposed this value as not cost effective.

[22] Percent control rate determined by the current emissions rate using a boiler firing rate of 360 MMBtu/hr, producing 250,000 pounds steam per hour compared to the potential emissions at the 0.01 gr/dscf vendor guarantee and the design exhaust flow rate of 200,000 acfm.

Technology	Description
Wet ESP (substitution)	A wet ESP could be completely substituted for the wet scrubber to get the improved particulate removal discussed in the previous paragraph, but a wet ESP would remove less SO_2 than the existing wet scrubber does. The economic analysis would be based on the same particulate emissions reduction as when the unit was being considered in series with the existing scrubber. Since SO_2 contributes to visibility impact, and the particulate reduction would be the same for either option, the complete substitution of the existing wet scrubber with a wet ESP option was not considered further.

2.3.2 NO_X Control Options

The No. 10 Power Boiler is a load-following spreader stoker combination fuel boiler with tangentially fired oil burners. It combusts wood waste, sludge, OCC rejects, and oil. The spreader stoker design inherently uses a form of staged combustion. In the PTPC Mill's No. 10 Power Boiler, the fuel-rich combustion of the wood waste on the grates results in incomplete combustion and lower flame temperatures. Downstream of the primary flame, the horizontally opposed overfire air ports supply excess air to complete the combustion. Further downstream, the tangential oil burners supply additional heat without increasing the primary flame temperature. This firing configuration results in low peak flame temperatures, and minimal thermal-NO_X formation. As a result, the majority of the NO_X from wood-fired boilers is fuel NO_X.[23] Table 2-2 lists the control technologies considered for the No. 10 Power Boiler. Appendix C contains a discussion of the reasons why each of these additional control options was proposed to be technically infeasible for NO_X control. The discussion was put into an appendix because of its length.

2.3.3 SO_2 Control Options

Implementation of **FGD technology using wet injection with a wet scrubber** on the No. 10 Power Boiler could reduce SO_2 emissions. This technology would involve adding additional alkaline chemicals such as lime or sodium hydroxide to the existing wet scrubber solution. This addition would further increase the pH of the scrubber effluent, which would in turn increase the pH of the ash clarifier into which the scrubber effluent empties. The ash clarifier's pH currently ranges from 11 to 12.2 as a result of the alkaline nature of the fly ash removed by the wet scrubber. The clarifier has a pH limit of 12.45 to ensure that the sludge and scrubbing liquor are not classified as a dangerous waste under Washington State Dangerous Waste regulations and a hazardous waste under federal Resource Conservation and Recovery Act (RCRA) regulations. Increasing the pH of the ash clarifier to a pH of 12.5 or greater would result in generation of a sludge characterized as a state dangerous or RCRA hazardous waste. Such characterization would increase the cost and complexity of ash disposal significantly.

[23] NCASI Special Report 03-04, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience,* August 2003.

Aside from making the sludge into a state dangerous waste and RCRA hazardous waste, the implementation of wet FGD is unlikely to provide significant additional control of SO_2. The alkaline fly ash currently absorbs the SO_2 in the flue gas in the same manner as a FGD alkaline reagent. The calcium and sodium oxides in the fly ash captured by the existing wet scrubber causes the scrubber water to become alkaline, allowing for absorption of SO_2 in the scrubber water. Addition of more alkaline solution to the existing scrubber would provide only an incremental increase in SO_2 absorption.

Because of the above described issues of small increase in performance and significant problems with sludge disposal, PTPC proposed that the implementation of wet FGD technology for control of SO_2 from the No. 10 Power Boiler be considered technically infeasible.

Reducing sulfur content of the fuel is a common approach to reduce SO_2 emissions. This option is considered technically feasible, so a cost estimate to implement it was done. The cost of switching from the recycled fuel oil (RFO) currently fired in the No. 10 Power Boiler (and all other PTPC Mill oil-fired units) to 'High Spec' RFO with guaranteed maximum sulfur content of 0.5 percent ($43.53/barrel) is approximately $15,702 per ton of SO_2 emissions avoided. Switching from RFO to 500 ppm or 15 ppm sulfur diesel ($92.67/barrel) would cost approximately $19,650 per ton of SO_2 emissions avoided. Both 500 ppm and 15 ppm sulfur diesel fuel have essentially the same price per barrel. This estimate calculates the current SO_2 emissions based on the guaranteed maximum sulfur content of 0.76 percent in the RFO. The estimate also assumes that all sulfur in the fuel oil is emitted as SO_2[24] and none is absorbed in the fly ash. It does not include costs of any changes in plant equipment required to store or burn the new fuel.

PTPC proposed that this cost is too high for BART.

2.3.4 PTPC's BART Proposal for the No. 10 Power Boiler

For PM/PM_{10} control, PTPC proposed continued use of the existing wet scrubber as BART.

For NO_X control, PTPC proposed to continue using good operation of the boiler's inherent staged combustion system as BART.

For SO_2 control, PTPC proposed continued operation of the existing wet scrubber and continued good operation of the boiler aimed at minimizing fuel oil firing as BART.

2.4 Lime Kiln Control Options

As discussed in Section 1.3.4 the Lime Kiln currently uses a wet venturi scrubber to reduce PM/PM_{10} emissions. The calcium oxide particulates create alkalinity that enhances SO_2 scrubbing.

[24] For the cost analysis, SO_2 emissions are based on AP-42 Table 1.3-1 emission factor (157*S% lb $SO_2/10^3$ gallons), which assumes 100% of the sulfur in the oil is emitted as SO_2.

2.4.1 PM_{10} Control Options

The Lime Kiln's particulate emissions are currently regulated under 40 CFR 63 Subpart MM. The Lime Kiln meets these emissions requirements. The compliance date for Subpart MM was March 13, 2004. No new technologies for controlling PM have subsequently become available after this recent date. Therefore, PTPC considered the MACT limits for PM from the Lime Kiln as BART and did not analyze further options for PM emissions control.

2.4.2 NO_X Control Options

For purposes of product quality and process economics, PTPC operates its Lime Kiln using a minimum of excess air. This practice contributes to minimizing NO_X emissions.

A RACT/BACT/LAER Clearinghouse (RBLC) search results reveal that no add-on controls or combustion modifications have been required to meet RACT, BACT, or LAER. The database lists only requirements such as "good combustion" or "proper kiln design" as BACT for control of NO_X from a lime kiln.

Ten possible control options were investigated. PTPC proposed all were technically infeasible. A discussion of each of these technologies is found in Appendix D.

2.4.3 SO_2 Control Options

In addition to the SO_2 removal that occurs from the lime produced in the Lime Kiln, the current wet venturi scrubber captures lime dust making the scrubber solution more alkaline and promoting additional SO_2 reduction.

As listed in Table 2-3, several additional technologies were investigated for technical feasibility. After investigation, all were determined to be technically infeasible except for selection of a lower sulfur fuel oil and improved FGD within the existing wet scrubber. A discussion of each technically infeasible category is contained in Appendix E.

Lower sulfur fuel was rejected previously (see Section 2.3.3), because it was not economically justifiable. That analysis is valid throughout the plant, including the Lime Kiln, because it is based on the purchase price of the fuels alone and not installation or operation of equipment.

PTPC included the option of adding more alkali to the wet scrubber to attempt to provide an additional 90 percent control efficiency as the BART 102 modeling scenario described in Section 3. The visibility impact reduction as described in Section 3 was estimated to be 0.004 dv. This small change is understandable considering that existing SO_2 emissions from the Lime Kiln are only about one percent of the total SO_2 emissions of PTPC's BART units. The minimal emissions reduction and visibility impact reduction indicated this option is not BART.

2.4.4 PTPC's BART Proposal for the Lime Kiln

For PM_{10} control, PTPC proposed continued use of the existing wet venturi scrubber as BART. PTPC will continue to operate the current scrubber to comply with the existing NESHAP Subpart MM limit of 0.064 gr/dscf at 10 percent O_2.

For NO_X control, PTPC proposes that proper kiln design and operation as BART for NO_X emissions.

For SO_2 control, PTPC proposes continued operation of the Lime Kiln wet venturi scrubber as BART.

2.5 PTPC's Proposed BART

Table 2-6. SUMMARY OF PTPC'S PROPOSED BART

Pollutant	Emission Unit	Proposed BART Control Option	Control Option Emissions Level or Control Efficiency
PM_{10}	No.10 Power Boiler	Existing Wet Scrubber[a]	0.10 lb/MMBtu[b] (current NSPS Subpart D limit)
	Recovery Furnace	Existing ESP	0.044 gr/dscf[b] (current MACT Subpart MM limit)
	Smelt Dissolving Tank	Existing Wet Scrubber	0.200 lb/BLS[b] (current MACT Subpart MM limit)
	Lime Kiln	Existing Venturi Scrubber	0.064 gr/dscf[b] (current MACT Subpart MM limit)
NO_X	No. 10 Power Boiler	Existing Staged Combustion System	0.80 lb/MMBtu[b] (current NSPS Subpart D limit)
	Recovery Furnace	Existing Staged Combustion System	N/A[c]
	Smelt Dissolving Tank	N/A	N/A[c]
	Lime Kiln	Good Operating Practices	N/A[c]
SO_2[e]	No. 10 Power Boiler	Good Operating Practices	0.30 lb/MMBtu[b]
	Recovery Furnace	Good Operating Practices	200 ppm @ 8% O_2[b] (current PSD limit)
	Smelt Dissolving Tank	Good Operating Practices	N/A[b,c]
	Lime Kiln	Existing Venturi Scrubber[d]	Continued use of wet scrubber with inherently alkaline scrubber solution 500 ppm @ 10% O_2[b] (current WAC limit)

[a] The addition of a wet ESP to the existing wet scrubber on the No. 10 Power Boiler is determined to not be cost effective. However, the visibility impact of implementing this control technology is evaluated as BART 101 for informational purposes to further support the ineffectiveness of implementing this control technology.

[b] For the purposes of presenting this BART emissions limit summary, for the baseline case (where no controls are applied), the existing emissions limits proposed as BART are listed in this table. However, the baseline emission rates used for the BART determination visibility modeling analysis are the maximum actual daily emission rates as presented and modeled for the BART applicability analysis rather than these maximum emissions limits.

[c] There are no current limits that apply to the emission unit for the specified pollutant.

[d] The addition of alkaline solution to the scrubber was found to be cost ineffective. However, the visibility impact of implementing this control technology is evaluated as BART 102 for informational purposes to further support the ineffectiveness of implementing this control technology.

[e] Switching to a lower sulfur content recycled fuel oil (RFO) was determined to be economically infeasible as discussed in Section 2.3.3.

3. VISIBILITY IMPACTS AND DEGREE OF IMPROVEMENT

A baseline Class I Area visibility impact analysis was performed on the BART-eligible emission units at the PTPC Mill using the CALPUFF model with four kilometer grid spacing as recommended by Oregon/Idaho/Washington/EPA Region 10 BART modeling protocol. The 98th percentile modeled 24-hour average visibility impacts modeled for the BART eligible units at the PTPC Mill at each Class I area within 300 km and in the Columbian River Gorge National Scenic Area are shown in Table 3-1.

Table 3-1. BART APPLICABILITY VISIBILITY MODELING RESULTS

Class I Area	22nd highest Δdv, 2003-5 (98th %ile)	8th High 2003 Δdv	8th High 2004 Δdv	8th High 2005 Δdv
Alpine Lakes Wilderness Area	0.284	0.264	0.281	0.313
Glacier Peak Wilderness Area	0.251	0.226	0.238	0.258
Goat Rocks Wilderness Area	0.137	0.137	0.128	0.134
Mount Adams Wilderness Area	0.124	0.128	0.124	0.105
Mount Rainier National Park	0.244	0.272	0.231	0.211
North Cascades National Park	0.236	0.196	0.248	0.236
Olympic National Park	**1.919**	**1.767**	**1.983**	**1.919**
Pasayten Wilderness Area	0.125	0.120	0.147	0.123
Columbia River Gorge National Scenic Area (not a Class I area)	0.060	0.064	0.069	0.043

The BART applicability modeling results presented in Table 3-1 indicates that the 98th percentile visibility impact exceeds the 0.5 dv contribution threshold at only one of the eight Class I areas, Olympic National Park.

After modeling visibility impacts of the BART eligible units at the plant, PTPC proposed three modifications to the initial scenario, to better model the impacts at Olympic National Park:

1) Refinements to the unit emissions used for modeling, applicable to both baseline and control technology modeling
2) Use a different background ammonia concentration (0.5 ppb) from the one specified in the modeling protocol (17 ppb)
3) Use of the new IMPROVE equation.

Ecology did not accept the latter two changes, as they deviated from the modeling protocol. Modeling files submitted by the company were used to extract the visibility impairment based on the old IMPROVE equation. PTPC was requested to rerun some of the post processing steps, so as to revert back to using the 17 ppb ammonia background.

Specific emission changes between the initial BART screening modeling and the final modeling presented in this BART analysis are discussed in Section 6.3 of the BEST AVAILABLE

RETROFIT TECHNOLOGY APPLICABILITY ANALYSIS AND DETERMINATION REPORT, PORT TOWNSEND PAPER CORPORATION, December 2007. These changes, which affected all emissions from the No. 10 Power Boiler and the particulate emissions from the Smelt Dissolving Tank and the Lime Kiln, were accepted by Ecology.

The revised emission rates are summarized in Table 3-2. They result in a modeled 98th percentile visibility impact of 1.614 ΔDV at Olympic National Park. This final baseline modeling result is used as the basis for comparing changes in the remainder of the modeled impacts discussion.

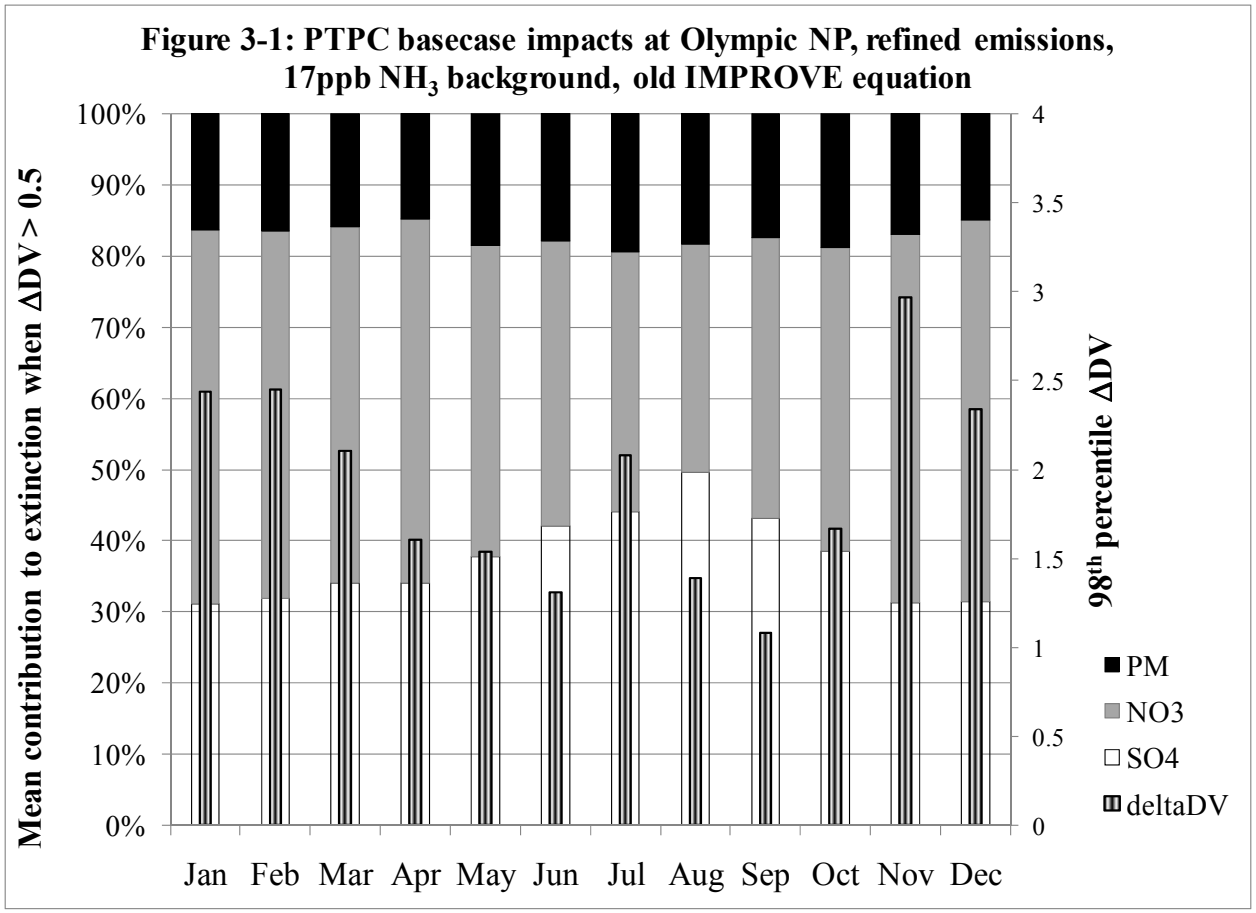
Table 3-2. MAXIMUM 24-HOUR AVERAGE ACTUAL EMISSION RATES

Emission Unit	NO_X (lb/hr)	SO_2 (lb/hr)	H_2SO_4 (lb/hr)	Filterable PM_{10}[a] (lb/hr)	Total PM_{10}[b] (lb/hr)
Recovery Boiler	78.76	105.76	1.66	19.53	24.25
Smelt Dissolving Tank	1.05	0.26	0.11	9.55	9.94
No. 10 Power Boiler	82.61	71.39	8.09	31.59	56.62
Lime Kiln	9.98	1.61	0.78	6.35	7.69

[a] Filterable PM_{10} represents the sum of the modeled filterable PM speciation groups of PMC, PMF, and EC.
[b] Total PM_{10} (TPM_{10}) represents the sum of the modeled filterable and condensable PM, including sulfuric acid (H_2SO_4).

An evaluation of the modeling results show that on an annual basis, NO_X and SO_2 emissions from PTPC each contribute about 40 percent of PTPC's total visibility impact on Olympic National Park. The particulate emissions contribute about 20 percent to visibility impact on the park. Seasonally, the contribution of NO_X, SO_2, and particulate to the modeled visibility impairment varies.

Total visibility impacts are lower during the summer. In the summer, SO_2 from the PCTP Mill can contribute up to about a 50 percent of the visibility impairment caused by the plant, while in the winter NO_X can contribute up to about 50 percent of the visibility impairment caused by the PTPC Mill. The relative contribution of particulate emissions is fairly stable year round at about 18 percent. Figure 3-1 shows the monthly distribution of the days with high impacts (i.e. ΔDV > 0.5) and the breakdown by species.



Net Visibility Improvement

PTPC evaluated the potential visibility improvement that could occur if two of the emissions reduction options were implemented individually. Table 3-4 outlines these modeling scenarios.

Table 3-4. NET VISIBILITY IMPROVEMENT ANALYSIS CONTROL SCENARIOS

Modeling Scenario	Scenario Description
BART100	**Baseline Scenario**
BART101	With Power Boiler No. 10 PM_{10} reductions from the addition of a wet ESP (reduction of PM_{10} emissions to 0.01 gr/dscf vendor guarantee)
BART102	With Lime Kiln SO_2 emissions control from addition of alkaline solution to the existing wet venturi scrubber (assumed 90% emissions reduction of SO_2)

Table 3-5 summarizes the visibility impacts and potential improvement at Olympic National Park for the baseline scenario and the two control option scenarios. The impacts are expressed in terms of the maximum 98th percentile (22nd highest day) 24-hour average visibility impact over the three years of meteorological data modeled.

Table 3-5. BART DETERMINATION VISIBILITY IMPACTS AT

OLYMPIC NATIONAL PARK

Modeling Scenario	98th Percentile Δdv (22nd high in 3 years)	Net Visibility Improvement over Baseline
BART100 (baseline)	1.614	
BART101(PB#10)	1.355	-0.259
BART102 (Lime Kiln)	1.610	-0.004

The modeling results indicate a visibility improvement of 0.259 dv could result from the addition of a wet ESP to further reduce PM_{10} emissions from the No. 10 Power Boiler. The visibility improvement which could result from a 90 percent reduction of SO_2 from the Lime Kiln scrubber is 0.004 dv. PTPC proposed that both emission reduction options were economically infeasible.

4. ECOLOGY'S BART DETERMINATION

Ecology has reviewed the information submitted by PTPC. Ecology agrees with the analyses performed by PTPC and has determined that the current levels of control are BART for the four BART-eligible process units. The controls and emission limitations are summarized in Table 4-1 below.

Table 4-1. ECOLOGY'S DETERMINATION OF EMISSION CONTROLS THAT CONSTITUTE BART

Emission Unit	Pollutant	BART Control Technology	Emission Limitation
NDCE Recovery Furnace	PM_{10}	Existing ESP	NESHAP Subpart MM limit of 0.044 gr/dscf at 8% O_2
	NO_X	Existing staged combustion system	No limit
	SO_2	Good Operating Practices	PSD permit limit of 200 ppm @ 8% O_2
Smelt Dissolving Tank	PM_{10}	Existing wet scrubber	NESHAP Subpart MM limit of 0.20 lb PM10 per ton BLS
	NO_X	No controls	No limit
	SO_2	Existing wet scrubber	No limit
No. 10 Power Boiler	PM_{10}	Existing multiclone and wet scrubber	NSPS Subpart D limit of 0.10 lb/MMBtu
	NO_X	Existing staged combustion system	NSPS Subpart D limit of 0.30 lb/MMBtu
	SO_2	Good Operating Practices	NSPS Subpart D limit of 0.80 lb/MMBtu
Lime Kiln	PM_{10}	Existing venturi wet scrubber	NESHAP Subpart MM limit of 0.064 gr/dscf @ 10% O_2
	NO_X	Good Operating Practices	No limit
	SO_2	Existing wet scrubber	500 ppm @ 10% O_2

4.1 Recovery Furnace BART Determination

For PM/PM_{10} emissions control, Ecology determined that BART is the current level of control provided by the existing ESP. Actual emissions from use of the current ESP average less than 50 percent of the NESHAP (MACT) Subpart MM limit of 0.044 gr/dscf at eight percent O_2. The compliance date for the MACT was March 13, 2004. No new technologies for controlling PM

have become available since then, and the MACT limitation is the strictest limitation currently existing for PM/PM_{10} applicable to this Recovery Furnace.

Since the Recovery Furnace currently utilizes a dry ESP system to control particulate emissions, Ecology made a planning level estimate of the cost to reduce particulate emissions further using cost estimating tools available from EPA's OAQPS.[25] The estimate showed that improvements to the ESP to reduce the BART modeled 106 tpy of particulate emissions in half could cost about $5,100 dollars per ton of particulate removed. As shown in Table 3-2, a reduction of 50% of the recovery furnace particulate emissions would result in approximately a 12% reduction in total particulate emissions from the PTPC plant site. Scaling this from Figure 3-1, this would indicate a small visibility improvement of about 0.07 dv. Ecology considers this improvement to the ESP performance to not be cost effective.

For NO_X control, Ecology has determined that BART is the current level of control provided by the existing staged combustion system. Good combustion practices that optimize the staged combustion inherent in the design of the furnace are the only available technology for control of NO_X that has been demonstrated on recovery boilers. Ecology agrees that the available alternative NO_X control technologies are technically infeasible.[26]

Ecology evaluated the use of a wet scrubbing system to reduce SO_2 from the recovery furnace. Ecology is aware of three recovery furnaces in the Northwest using a wet scrubber to reduce SO_2 emissions, the oldest having been in operation since at least the mid 1980s. Two units are still operational (at Georgia Pacific Camas), but one was shut down in the early 2000s (Longview Fibre). These scrubbers were originally installed to recover waste heat for use in the plant by making hot water by directly contacting the water stream with the hot stack gases. In order to use the hot water produced in this process, the flue gas concentrations of particulate and SO_2 needs to be significantly reduced prior to making the hot water. As a result, this heat recovery process provides some ancillary control of sulfur and particulate emissions.

Ecology's review of recent EPA RBLC recovery furnace entries generally confirms that for most recovery furnaces, installing a scrubber was not considered Best Available Control Technology (BACT). However, one wet scrubber was listed.[27]

Examination of 1997-2007 stack tests on the PTPC recovery furnace showed that SO_2 emissions are typically very low, with most tests showing less than 20 ppm (which was the limit on the GP Camas plant scrubbers). Emissions from a few of the tests were higher than 20 ppm, with the highest near 160 ppm. This testing history indicates that the recovery furnace routinely operates at low SO_2 emission rates, but periodically experiences sporadic short term "spikes" in SO_2 emissions.

[25] EPA Control Cost manual methods were used to calculated costs which were inflated to 2007 dollars.
[26] See Appendix B of this report for further discussions of these technologies.
[27] Meadwestvaco Kentucky, Inc, RBLC entry KY-0085

The EPA scrubber fact sheet indicates[28] that scrubbers with inlet concentrations of 250 to 10,000 ppm can have scrubbing efficiencies of 80 to 99 percent. A scrubber operating at 20 ppm would be expected to be less efficient.

At Ecology's request, PTPC provided a rough estimate of the cost of installing a scrubber to remove SO_2 from the recovery furnace emissions. PTPC assumed a cost of $34 per scfm airflow for this type of wet scrubber.[29] At 250,000 scfm (wet basis) with an assumed 90 percent scrubbing efficiency that removed 417 tpy SO_2, the cost would be $20,383 per ton of SO_2 removed. If the scrubber could not achieve 90 percent efficiency, the cost would be higher. This cost estimate did not consider any site specific retrofit costs.

PTPC concluded the installation of a scrubber to control SO_2 emissions from their recovery furnace to not be cost effective.

For SO_2 control, Ecology has determined that BART is the current level of control provided by the existing staged combustion system operated to minimize loss of sulfur chemicals from the furnace.

4.2 Smelt Dissolving Tank BART Determination

For PM/PM_{10} emissions control, Ecology has determined that BART is the current level of control provided by the existing scrubber and meeting the emission limitation in 40 CFR 63, Subpart MM of 0.20 lb PM_{10} per ton BLS.

For SO_2 control, Ecology has determined that BART is the current level of control provided by the Smelt Dissolving Tank's existing wet scrubber.

4.3 No. 10 Power Boiler BART Determination

For PM_{10} control, Ecology evaluated the controls proposed by PTPC and also looked at the potential to modify the existing wet scrubbing system to provide additional particulate removal.

As discussed in Section 1.3.3, the existing Turbotak wet scrubber was installed in 1988, replacing a venturi scrubber. It is continuously maintained. Routine testing has shown it has consistently operated at between 1/3 and 1/2 of its NSPS based limit of 0.1 gr/dscf since its installation. The emission rate for this unit used in the BART visibility impact modeling reflects this low actual emission rate. BART modeling (see Figure 3-1) indicates that particulate emissions contributed the smallest part of PTPC's visibility impacts. Ecology determined that the small visibility improvement potential from upgrading the scrubber did not justify a full engineering study of the scrubber to determine possible particulate scrubbing improvements.

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[28] US EPA CATC, *Air Pollution Control Technology Fact Sheet – Spray Tower Wet Scrubber,* EPA-451/F-03-016, July 2003. Available at **www.epa.gov/ttn/catc/dir1/fsprytwr.pdf**.

[29] Cost derived from data in US EPA CATC, *Air Pollution Control Technology Fact Sheet – Spray Tower Wet Scrubber,* EPA-451/F-03-016, July 2003. Available at **www.epa.gov/ttn/catc/dir1/fsprytwr.pdf**.

As noted previously, the cost effectiveness of installing a wet ESP is $11,294 per ton of PM_{10} reduced for approximately 109 tpy of emissions reductions. Modeling indicates a definite visibility improvement could occur. However, Ecology determines that the cost of the improved particulate control is too high to justify as BART.

For PM_{10} control, Ecology has determined that BART is the current level of control provided by the existing wet scrubber.

For NO_X control, Ecology has determined that BART is the current level of control provided by proper operation of the boiler's staged combustion system as BART. Ecology could not find a technically feasible NO_X control technology available for retrofit on this boiler. The spreader-stoker design of the No. 10 Power Boiler inherently uses staged combustion, resulting in lower flame temperatures and minimal thermal NO_X formation.

Ecology reviewed BART and further progress evaluations proposed by other states where switching to lower sulfur content fuel oils was considered. Many of the States in the NESCAUM region are considering mandating low sulfur fuel oils for further progress requirements to reduce visibility impairment. NESCAUM evaluated the cost differential of lower sulfur fuels compared to the current fuel oils and determined a range of expected cost effectiveness. For the NE states the cost of this measure was expected to be $500 – 750/ton SO2 reduced. Well below the costs predicted for PTPC.

New Hampshire evaluated the costs for lower sulfur residual oils for the Newton Station and determined that BART for SO_2 is a change from 2% sulfur residual oil to 1% sulfur residual oil for a cost effectiveness of $1900 per ton SO_2 reduced, a value considerably less than the costs for PTPC.

For SO_2 control, Ecology has determined that BART is continued operation of the existing wet scrubber, continued use of the current low sulfur fuels, and implementing good combustion practices aimed at minimizing recycled fuel oil firing as BART.

4.4 Lime Kiln BART Determination

For PM_{10} control, Ecology has determined that BART is the current level of control provided by the existing wet venturi scrubber and compliance with the 40 CFR Part 63, Subpart MM limit of 0.064 gr/dscf at 10 percent O_2.

For NO_X control, Ecology has determined that BART is proper kiln design and Good Operating Practices. Operation using a minimum of excess air minimizes NO_X emissions as well as promoting product quality and process economics.

For SO_2 control, Ecology has determined that BART is the current level of control provided by the Lime Kiln wet venturi scrubber as BART.

APPENDIX A. COMPILATION OF AVAILABLE PM, NO_X, AND SO_2 CONTROL OPTIONS FOR ALL UNITS

Available PM Control Technologies	
Technology	**Description**
Fabric Filter (baghouse)	A fabric filter (baghouse) consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Dirty gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the baghouse. A variety of fabrics is available to cover fuel gas temperatures up to about 650°F. Baghouses are unsuitable for use on water saturated gas streams.
Cyclone Separators	Cyclone separators remove solids from the air stream by application of centrifugal force. In solid fuel combustion devices like hog fuel boilers, they are commonly used to remove large particles prior to the flue gas entering a baghouse or ESP.
Wet Scrubbers	Wet scrubbers intercept dust particles using droplets of liquid (usually water). The larger, particle-enclosing water droplets are separated from the remaining droplets by gravity. The solid particulates are then separated from the water.
Electrostatic Precipitator (ESP)	An electrostatic precipitator (ESP) removes particles from an air stream by electrically charging the particles, then passing them through a force field that causes them to migrate to an oppositely charged collector plate. The dust from the collector plates falls into a collection hopper at the bottom of the ESP. The collection efficiency of an ESP depends on particle diameter, electrical field strength, gas flowrate, and plate dimensions. ESPs can be designed for both dry and wet applications.
Electrified Gravel Bed Filters (EGFs)	Electrified gravel bed filters (EGFs) are a technique that is no longer implemented in Washington State. It used electricity to generate an electrostatic charge on a moving bed of gravel to collect particulate from a wood-fired boiler. The last unit operating in Washington was recently replaced with a baghouse.
Proper Operating Practices	A properly operated emission unit will minimize the formation of PM_{10} emissions. Proper design of combustion units (e.g., boiler and recovery furnaces) concerns features such as the fuel and combustion air delivery system and the shape and size of the combustion chamber. Good operating practices for combustion units typically consist of controlling parameters such as fuel feed rates and air/fuel ratios.

Available NO_X Control Technologies	
Technology	**Description**
Low Excess Air (LEA)	Low excess air (LEA) is a technique where combustion is optimized by reducing the excess air introduced to the unit to the minimum necessary for stable, efficient combustion. Excess air is the air supplied in addition to the quantity required for stoichiometric combustion.
Staged Combustion Technologies	Staged combustion technologies such as overfire air (OFA) reduce NO_X emissions by creating a "fuel-rich" zone via air staging (diverting a portion of the total amount of air required through separate ports). For typical staged combustion, there is a slight excess of air in the initial burn zone. The highest temperatures are reached here, generating thermal NO_X. In the secondary burn zone, a secondary burner injects additional fuel into the marginally lean air, creating strongly rich air (i.e., more fuel is present than oxygen available to oxidize the fuel). In this reducing atmosphere, NO is reacted to N as the hydrocarbons and CO scavenge oxygen. For proper operation, the secondary burn zone must be between 1,800 and 2,200°F. Following this section is the final burn zone, where secondary air (from the cooler) provides sufficient oxygen to oxidize the remaining combustibles.
Flue Gas Recirculation (FGR)	Flue gas recirculation (FGR) reduces peak flame temperature by recirculating a portion of the flue gas back into the combustion zone as a replacement for combustion air. The recirculated gasses have a lower oxygen content that reduces the peak flame temperature in the combustion zone.[30]
Low NO_X Burners (LNB)	Low NO_X burners (LNB) are a technique with limited applicability to pile burning wood-fired boilers and recovery furnaces. Low NO_X burners modify the initial combustion conditions to reduce the peak flame temperature and are often used in conjunction with modifications to overfire air systems. They are most useful when using fuels like natural gas or distillate oil.
Fuel Stating (regurning)	Fuel stating (Regurning) is also known as "reburning" or "off-stoichiometric combustion." Fuel staging is a technique where ten to twenty percent of the total fuel input is diverted to a second combustion zone downstream of the primary zone. Again, this is a technique to reduce the peak flame temperature during combustion
Water/ Steam Injection	Water/steam injection into the main flame can reduce the flame temperature and the generation of NO_X. It is an older technique most often used on older burner designs in natural gas and oil-fired boilers and gas turbines. If the flame temperature is sufficiently quenched, the

[30] Prasad, Arbind, "Air Pollution Control Technologies for Nitrogen Oxides," *The National Environmental Journal*, May/June 1995.

Available NO_X Control Technologies	
Technology	**Description**
	generation of CO can increase and the process efficiency will decrease.
Mid-Kiln Firing	Mid-kiln firing is a form of staged fuel combustion specifically applied to cement and lime kilns. A specially designed fuel injection system introduces a second fuel source at a midpoint in the kiln.[31]
Mixing Air Fan (mid-kiln air lances)	For lime kilns, this technology is a method of staging combustion air through the use of a fan that is mounted on the rotating kiln shell. This can reduce NO_X formation by decreasing peak flame temperatures.
Good Operating Practices and Proper Design	The formation of NO_X can be minimized by proper operation and design practices. Operators can control the combustion stoichiometry to minimize NO_X formation while achieving efficient fuel combustion. This is the most basic combustion modification technique available.
Selective Non-Catalytic Reduction (SNCR)	Selective non-catalytic reduction (SNCR) is an exhaust gas treatment process in which urea or ammonia is injected into the exhaust gas. High temperatures, normally between 1,600 and 1,900°F, promote the reaction between urea or ammonia (NH_3) and NO_X to form N_2 and water.[32] The effectiveness of SNCR systems depends upon six main factors: (1) inlet NO_X concentration, (2) temperature, (3) mixing, (4) residence time, (5) reagent-to-NO_X ratio, and (6) fuel sulfur content.[33]
Selective Catalytic Reduction (SCR)	Selective catalytic reduction (SCR) is an exhaust gas treatment process in which NH_3 or urea is injected into the exhaust gas upstream of a catalyst bed for exhaust temperatures between 450 and 750°F.[34] In the SCR process, the urea or NH_3 injected into the exhaust is stored in a liquid storage tank and vaporized before injection. The exhaust/ammonia mixture then passes over the catalyst. The function of the catalyst is to lower the activation energy of the NO decomposition reaction, therefore, lowering the temperature necessary to carry out the reaction. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) reacts to form diatomic nitrogen (N_2) and water. When operated within the optimum temperature range, the reaction can result in removal efficiencies between 70 and 90 percent.[35] The rate of NO_X removal increases with temperature up to a maximum removal rate at a temperature between 700 and 750°F. As the temperature increases

[31] Battye et al., EC/R Incorporated, *"NOx Control Technology for the Cement Industry"* Final report prepared for EPA, September 19, 2000, Page 65.
[32] NCASI Special Report 03-04, *NOxNOX Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.
[33] Ibid.
[34] Ibid.
[35] 65Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NO_X Controls, EPA/452/B-02-001, pp. 2-9.

Available NO_X Control Technologies	
Technology	**Description**
	above the optimum temperature, or decreases below the optimum range for a conventional vanadium pentoxide catalyst, the NO_X removal efficiency begins to decrease.[36] Depending on the temperatures involved, low temperature and higher temperature catalyst formulations are available. The effectiveness of an SCR system depends upon the same factors as the SNCR system and the condition of the catalyst. The catalyst can degrade over time due to poisoning, fouling, thermal stress, and erosion by particulates, reducing the NO_X removal efficiency of the SCR system.[37]
Oxidation/ Reduction (O/R) Scrubbing	Several proprietary oxidation/reduction (O/R) scrubbing NO_X removal processes are commercially available. The basic elements of a typical process include cooling of the combustion gas stream below its dew point to condense water, treat with ozone or sodium chlorite to oxidize NO_X and SO_2 to their highest oxidized forms, then absorb these oxides as acids in a scrubber. It has been reported that O/R scrubbing has a theoretical NO_X removal efficiency of 95 percent.[38]

SO_2 controls can be placed into three groups: (1) wet flue gas desulphurization systems, (2) dry or semi-dry flue gas desulphurization systems, and (3) low sulfur fuels.

Available SO_2 Control Technologies	
Technology	**Description**
Flue Gas Desulfurization (FGD) with a Wet Scrubber	In flue gas desulfurization (FGD) with a wet scrubber**,** a solution of sodium or calcium hydroxide absorbs SO_2 from the flue gas forming sodium or calcium sulfite. The collected sulfite can be further oxidized to sulfate or left as the sulfite. Typically, large quantities of liquid or solid wastes are generated requiring disposal.[39]
Semi-Dry Lime Hydrate Slurry Injection FGD	For lime hydrate slurry injection, calcium hydroxide in the form of lime slurry is injected into the gas stream. Calcium hydroxide and SO_2 will react to form calcium sulfite. A fabric filter or ESP will be needed to remove the dry solid reaction products from the gas stream.

[36] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NOx Controls, EPA/452/B-02-001, pp. 2-10.
[37] NCASI Special Report 03-04, NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience, August 2003.
[38] Ibid.
[39] Cooper, C. David and Alley, F.C. *Air Pollution Control – A Design Approach, 2nd Edition*. Waveland Press: Prospectus Height, Illinois, 1994.

Available SO_2 Control Technologies	
Technology	**Description**
Dry Lime Powder Injection FGD	Dry lime powder injection FGD controls SO_2 using the same methods as lime hydrate slurry injection and depends on most of the same parameters. As with the lime slurry, a fabric filter or ESP is needed to remove the solid reaction products from the gas stream.[40]
Spray Dryer with an ESP FGD	Spray dryer with an ESP FGD requires installation of a spray dryer and an ESP. Dry lime is injected by a spray dryer into the flue gas in the form of fine droplets under well controlled conditions such that the droplets will absorb SO_2 from the flue gas and then become dry particles because of the evaporation of water. The dry particles are captured by the ESP downstream of the dryer. The captured particles are then removed from the system and disposed.[41]
Low Sulfur Fuel Selection	SO_2 emissions are influenced by the sulfur content of the fuel as well as the sulfur content of the process material. For the Recovery Furnace, the black liquor solids are both the fuel and the material being processed. In the case of the Smelt Dissolving Tank, there is no fuel burning, and in the case of the No. 10 Power Boiler, there is no process material. For the Lime Kiln, the fuel is the dominant source of sulfur rather than the lime feed.
Increased Oxygen Levels at the Burner	Increased oxygen levels at the burner have been shown to decrease SO_2 emissions from lime kilns. The increase in oxygen drives the SO_2 to SO_3 allowing the SO_3 to react with lime to produce $CaSO_4$.
Good Operating Practices	Good operating practices imply that the emission unit is operated within parameters that minimize emissions of air pollutants and maximize combustion efficiency.

[40] Chemical Lime Company Material Safety Data Sheet, Calcium Hydroxide.
[41] Cooper, C. David and Alley, F.C. *Air Pollution Control – A Design Approach, 2nd Edition.* Waveland Press: Prospectus Height, Illinois, 1994.

APPENDIX B. TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES FOR THE RECOVERY FURNACE

Technique	Feasibility Issues/Problems/Limitations
Low Excess Air	Results in the production of smoke, increased CO emissions, and other problems associated with the furnace operation, such as increased corrosion and fouling.[42]
Flue Gas Recirculation	Does not significantly reduce NO_X emissions when firing black liquor solids in a recovery furnace since the majority of NO_X emissions arise from fuel nitrogen. The corrosive conditions inherent in the firing of black liquor solids prevents the use of FGR as the fly ash in the flue gas stream would accumulate in the ductwork required for FGR and absorb moisture, resulting in duct pluggage and severe corrosion. Additionally, the reduced oxygen concentration formed in the furnace by FGR would result in an unacceptable increase in CO emissions. The increased flue gas volume would increase gas velocity in the super heaters and furnace bank, which can cause additional pluggage and lost capacity.
Low NO_X Burners (LNB)	The fireside conditions in a kraft recovery furnace do not accommodate LNB; usage of LNB would prohibit use of multi-stage air feeds and multiple small fuel nozzles, compromising the burners' intended purpose of chemical recovery and impacting their ability to support liquor burning and hearth bed control. The use of low NO_X burners has not been successfully demonstrated for a kraft recovery furnace application.[43]
Fuel Staging	Usage of fuel staging is generally limited to natural gas or distillate oil combustion. Under normal operation, the furnace combusts mostly black liquor solids. The black liquor solids cannot be diverted to a second combustion zone without negatively impacting the delicate balance of the kraft recovery process.
Water/Steam Injection	When firing black liquor solids in a recovery furnace, the majority of NO_X emissions arise from fuel nitrogen. Water/steam injection controls primarily thermal NO_X.
Selective Non-Catalytic Reduction (SNCR)	SNCR for control of NO_X emissions from a kraft recovery furnace has never been demonstrated on a long-term basis and is not listed on the RBLC for any recovery furnace.[44] The Recovery Furnace's complex chemical reaction balance can be upset by the SNCR usage, potentially damaging the furnace and negatively impacting product quality. Optimum NH_3/NO_X molar ratio and correct reaction temperatures would be difficult to monitor and maintain due to fluctuations in furnace load and exhaust gas temperatures. This would cause loss of efficiency

[42] NCASI Special Report 03-04, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.
[43] NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions,* June 2006.
[44] NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions,* June 2006.

Technique	Feasibility Issues/Problems/Limitations
	and result in the release of NH_3 into the atmosphere. It is likely that formation of NH_3 salts would occur which could result in an increase of process downtime. The Recovery Furnace may operate at temperatures above 2,000°F. At temperatures exceeding 2,000°F, the NH_3 injected with the SNCR begins to oxidize, creating additional NO_X. While SNCR has been demonstrated during a short trial on a recovery furnace (which was decommissioned shortly after the trial concluded), long-term use of an SNCR system on a recovery furnace has never been evaluated.
Selective Catalytic Reduction	SCR technology for control of NO_X emissions from a kraft recovery furnace has never been demonstrated even on a short-term basis and is not listed on the RBLC for any recovery furnace.[45] The Recovery Furnace heat input and black liquor solids characteristics vary continuously. This causes temperature swings that would make efficient SCR operation difficult. Efficient operation requires constant exhaust temperatures within a defined range, usually ± 50°F. A low temperature results in slow reaction rates which lead to low nitrogen oxides conversion and unreacted NH_3 passing through the reactor bed (ammonia slip). A high temperature results in shortened catalyst life and can lead to the oxidation of NH_3 and the formation of additional NO_X. Controlling the feed rate of the SCR NH_3 reagent would also present unique technical considerations. NH_3 injection rates must be closely track the varying NO_X rate from the furnace to maintain a given level of NO_X control while simultaneously avoiding excess ammonia slip.
Oxidation/Reduction Scrubbing (including LoTOx)	The ability of an O/R scrubbing system (like LoTOx) to perform efficiently on a recovery furnace has not been demonstrated on a recovery furnace. There are about 10 installations of LoTOx technology on oil refinery FCCUs and 4 other installations of the technology. The principle operating cost is consumption of pure oxygen to produce ozone. A telephone call with the technology supplier indicated that they were focusing on the refining applications at this time.[46] An O/R scrubbing system is designed to complement control systems that already include a caustic scrubber, which PTPC's Recovery Furnace does not have (it has an ESP). If a caustic scrubber were installed on the Recovery Furnace, other technical difficulties would arise. The high moisture content of black liquor solids results in a flue gas dew point temperature that is expected to exceed 300°F, the maximum temperature for effective oxidation/reduction scrubbing. If the flue gas temperature is lowered to below 300°F where these processes work best, condensation liquids with high corrosion potential and disposal issues result. Bleed air or a water spray cooling tower are the technologies typically used to cool the stack gas stream. Increased air flow requires an increase in the size of the induced draft (ID) fan and its power consumption.

[45] Ibid.
[46] By Al Newman in March 2008.

APPENDIX C. TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES FOR THE NO. 10 POWER BOILER

Technique	Feasibility Issues/Problems/Limitations
Low Excess Air (LEA)	LEA is difficult to employ in spreader stoker boilers because high excess air levels are needed for proper fuel burning.[47] LEA is not anticipated to produce NO_X reductions beyond those already achieved by the staged combustion inherently practiced in the boiler. LEA can result in the production of smoke, increased CO emissions, and other problems associated with the boiler operation including increased corrosion and fouling.[48] Due to fluctuations in the fuel properties, a low level of overall excess air would likely cause incomplete combustion, resulting in increased CO emissions.
Flue Gas Recirculation (FGR)	FGR primarily reduces thermal NO_X. FGR would not significantly reduce NO_X emissions when firing a wood waste spreader stoker boiler since the majority of NO_X emissions arise from fuel nitrogen. The use of FGR would also result in soot fouling.
Low NO_X Burners (LNB)	LNB primarily reduce thermal NO_X. As with FGR, is not expected to significantly reduce NO_X emissions when firing a wood-waste spreader stoker boiler since the majority of NO_X emissions arise from fuel nitrogen. A combustion engineering (CE) representative stated that there is no commercially available low NO_X oil burner that can be retrofitted into a tangential type burner like those used in PTPC's No. 10 Power Boiler.
Fuel Staging (Reburning)	Traditional fuel staging (reburning) requires the use of natural gas or distillate oil in a secondary combustion zone downstream of the primary zone. The No. 10 Power Boiler does not use these fuels. Fuel staging often employs FGR, which is considered infeasible for hogfuel boilers due to its inability to minimize fuel NO_X, the primary component of NO_X from wood waste combustion.[49] PTPC's No. 10 Power Boiler inherently uses a process similar to fuel staging by design. The tangential oil burners, which typically supply approximately 30% of the heat to the boiler, are located downstream of the primary wood-fired flame.
Selective Non-Catalytic Reduction (SNCR)	SNCR technology has never been successfully demonstrated for wood-fired boilers with changing loads.[50] The No. 10 Power Boiler firing rate varies to meet the PTPC Mill's steam demand. It has been used on many wood-fired boilers where loads are steadier, like at sawmills.

[47] Washington State Department of Ecology Publication No. 03-02-009, *Hog Fuel Boiler RACT Determination*, April 2003, downloaded June 25, 2007, http://www.ecy.wa.gov/biblio/0302009.html.
[48] NCASI Special Report 03-04, *NOx Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience,* August 2003.
[49] NCASI Special Report 03-04, *NOx Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience,* August 2003.
[50] NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions,* June 2006.

Technique	Feasibility Issues/Problems/Limitations
	There are several reasons why SNCR technology has not been successfully implemented on load-following wood-fired boilers. The injection of the reagent must be applied in a narrow temperature window in order for the reduction reaction to successfully complete. In a load-following boiler, the region of the boiler where this temperature is located varies depending on the firing rate, making it difficult to control the SNCR reaction temperature. Another factor preventing proper implementation of SNCR technology in wood-fired boilers is inadequate reagent dispersion in the injection region, which can lead to significant amounts of unreacted ammonia exhausted to the atmosphere (i.e., large ammonia slip). At least one pulp mill wood-fired boiler had to abandon their SNCR system due to problems caused by poor dispersion of the reagent within the boiler.[51]
Selective Catalytic Reduction (SCR)	SCR technology has never been successfully demonstrated for a spreader stoker boiler.[52] There are several reasons. Size constraints often make locating an SCR system near the boiler impossible in retrofit situations. Most hogfuel boiler temperature profiles are not appropriate for SCR, and the SCR system pressure drop requirements result in sizing concerns related to existing boiler fans. NCASI notes that the high PM concentrations upstream of the PM control equipment would impede catalyst effectiveness and could result in deactivation or poisoning of the catalyst, while installation of SCR downstream of the PM control equipment would render the gas stream too cold for effective reaction with the catalyst to reduce NO_X. The desired temperature range for SCR application is 450 to 750°F, while the outlet temperature of the No. 10 Power Boiler's wet scrubber is less than 150°F. Reheating the flue gas would result in significant energy penalties.
Oxidation/ Reduction (O/R) Scrubbing	O/R scrubbing is not listed as a successfully demonstrated option in any RBLC determination. This technology is not considered readily available or proven for industrial boiler retrofit operations.[53] Even if such technology were to be considered proven and technically feasible for retrofit operations, it is unlikely to be cost feasible.[54]

[51] Ibid.
[52] Ibid.
[53] This technology is not evaluated as a readily available BART option in the BART guidance documents for industrial boilers issued by the Midwest RPO (*Midwest RPO Candidate Control Measures for Industrial, Commercial, and Institutional Boilers*, March 2005) or MANE-VU (*Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants, and Paper and Pulp Facilities*, March 2005).
[54] NCASI Special Report 03-04, *NOx Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience,* August 2003.

APPENDIX D. TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES FOR THE LIME KILN

Technique	Feasibility Issues/Problems/Limitations
Staged Combustion	Staged combustion, also known as staged air combustion or non-selective noncatalytic reduction (NSNCR), is comprised of an initial burn zone (oxidizing), a secondary burn zone (reducing), and a final burn zone (oxidizing). Although staged combustion can theoretically result in NO_X reductions of 20 to 50 percent, the technology is not listed as a control for NO_X in the RBLC database, and PTPC is aware of no lime kilns and only a few cement kilns using this technology. To date, PTPC is aware of only one full-scale industrial operation (a cement kiln in Brevik, Norway) using NSNCR that has reported on its experience. A recent paper reviews six years of operation of the Brevik plant. The Brevik plant included a low NO_X burner in addition to NSNCR. While positive results were initially reported, the averaged results over the six years show little improvement as compared to prior operation with a conventional burner and no NSNCR. In addition, long-term testing showed increases in CO and SO_2 concentrations.[55] Process differences between cement and lime production are the reason this technology has not been applied to the lime industry. A multi-stage pre-heater and cyclones, which a lime kiln does not have, are necessary for the staged combustion required for this control technology.
Mid-Kiln Firing	Although mid-kiln firing (MKF) can reduce NO_X emissions in cement kilns, the longer, lower temperature flame and the addition of fuel to the lime would negatively affect the quality of the lime produced. Introduction of fuel at mid-kiln will increase carryover of unburned carbon to the product. This unburned fuel will prevent the lime product from being used in many applications.[56] MKF is not listed for control of NO_X from a lime kiln in the RBLC.
Mixing Air Fan (mid-kiln air lances)	Mixing air fan (mid-kiln air lances) is a method of staging combustion air to reduce NO_X formation through the use of a fan that is mounted on the rotating kiln shell. However, a mixing air fan can create an oxidizing environment in the kiln in a location that may increase the sulfur content of the product to an unacceptable concentration. There has been no application of a mixing air fan on a lime kiln in the U.S.
Flue Gas Recirculation (FGR)	FGR involves routing a portion of the flue gas to the combustion area for the purpose of reducing the maximum flame temperature (and thus lowering thermal NO_X). Achieving high flame temperatures is critical in the lime production process. The flame temperature achieved using FGR would be below the temperature necessary for proper lime formation. In addition, a

[55] *NO_X Emission Control Technologies for Cement and Lime Kilns,* (Draft, 1995). Radian Canada, Inc.
[56] National Lime Association letter to Ms. Rosalina Rodriguez, North Carolina Department of Natural Resources, *Re: Comments on VISTA's Draft Regional Haze Modeling Protocol*, Ocotober 21, 2005.

Technique	Feasibility Issues/Problems/Limitations
	long and lazy flame will be produced, which is not acceptable for ensuring lime quality. FGR would also require an excessive amount of ducting from the stack to the kiln inlet. FGR has never been demonstrated on a lime kiln and is not listed in the RBLC.
Low NO_X Burners (LNB)	The RBLC does not indicate that LNB has been considered for a lime kiln. There is no commercially available low NO_X burner on the market for implementation in a lime kiln. A 2006 NCASI Corporate Correspondent Memorandum states that "[t]he concept of 'low NO_X burner' is considered a misnomer in the rotary kiln industry. . . In rotary kilns, it is not possible to stage the mixing in the same way [as low NO_X burners in a boiler]."[57] A LNB by design lowers the flame temperature of the burner and changes the flame shape. This is negative for quality control and the calcining process needed to convert a high percentage of $CaCO_3$ mud to CaO reburn lime in the Lime Kiln.
Fuel Staging	The major requirements for fuel staging are to have the fuel feed rate to the main combustion zone be reduced and have an equivalent amount of fuel being fed to the reburn burners in the reburn zone, located downstream of the main combustion zone. Reburning would require major changes for a lime kiln, which could impact the quality of the lime being produced. A lime kiln does not have an area that could be used as a "reburn zone," and additional heat is not needed for a lime kiln pre-heater. Due to these difficulties, this technology has not been previously applied to lime kilns.
Water/Steam Injection	The effectiveness of water/steam injection on lime kiln NO_X emissions is unproven, and this technology is not listed in the RBLC for lime kilns. Water or steam injection into a burner flame will reduce the flame temperature and the generation of NO_X, and is an old, well documented technology for NO_X reduction in boilers and gas turbines. As discussed earlier in the FGR section, the Lime Kiln requires high temperature operation to properly calcine lime. Water/steam injection decreases process efficiency along with flame temperature, and can increase CO generation.
Selective Catalytic Reduction (SCR)	SCR is not listed in the RBLC database for control of NO_X from a lime kiln. To avoid fouling the catalyst bed with the PM in the exhaust stream, an SCR unit would need to be located downstream of the particulate matter control device (PMCD). However, due to the low exhaust gas temperature exiting the PTPC Lime Kiln's wet scrubber PMCD (approximately 156°F); a heat exchanger system would be required to reheat the exhaust stream to the desired reaction temperature range of 450 to 750°F. The source of heat for the heat exchanger would be the combustion of fuel oil, which would

[57] NCASI Corporate Correspondent Memorandum No. 06-0142006, Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions, June 2006.

Technique	Feasibility Issues/Problems/Limitations
	generate additional NO_X and SO_2.
Selective Non-Catalytic Reduction (SNCR)	SNCR has never been demonstrated on a lime kiln and is not listed on the RBLC. Several difficulties preclude use of an SNCR for control of NO_X emissions from lime kilns. If burner temperatures exceed 2,000°F, the NH_3 injected with the SNCR will begin to oxidize, creating additional NO_X. It is also difficult to maintain the correct NH_3/NO_X ratio during load fluctuations. Excess NH_3 will be released into the atmosphere, creating NH_3 slip. NH_3 slip can form ammonium salts which form a visible plume.
Oxidation/ Reduction (O/R) Scrubbing	While O/R scrubbing has a high theoretical NO_X removal efficiency, the technology has never been installed for lime kilns or cement kilns.[58] Additionally, this technology is not listed in the RBLC database for lime kilns.

[58] Telephone conversation between Mr. Darryl Haley (Tri-Mer Corporation) and Mr. David Wilson (Trinity Consultants), October 18, 2001.

APPENDIX E. TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES FOR THE LIME KILN

Technique	Feasibility Issues/Problems/Limitations
Semi-Dry Lime Hydrate Slurry Injection FGD	For lime hydrate slurry injection, calcium hydroxide in the form of lime slurry is injected into the gas stream. A fabric filter or ESP would need to be installed on the kiln to remove the solid reaction products from the gas stream. After the calcium hydrate is injected into the gas stream, the slurry droplets will dry and the particulate matter will be removed from the stream by the fabric filter or ESP. The only possible location to inject the lime hydrate is in the feed chute, which is between the kiln and the pre-heater chamber. The gas residence time in the feed chute is approximately 0.9 seconds, the saturation temperature is approximately 350°F, the actual temperature in the chute is approximately 2000°F, and the SO_2 concentration is relatively low. The injection of lime hydrate slurry at this location will not be effective because the ΔTsat temperature is too large (1650°F), the residence time is too short, and the SO_2 concentration is low. Another possible location for injection would be after the kiln and pre-heater, but before the fabric filter or ESP. However, the kiln already has excess reactive lime available and providing additional lime will not have an appreciable contribution to reducing emissions. In addition, injection at this location is not effective due to the low temperature and low SO_2 concentration.
Dry Lime Hydrate Powder Injection	For lime hydrate powder injection, calcium hydroxide in the form of a lime powder is injected into the gas stream. As with the lime slurry, a fabric filter or ESP would need to be installed on the kiln to remove the solid reaction products from the gas stream. The dry lime hydrate can be also be injected in either the feed chute or prior to the fabric filter or ESP. Hydrated lime decomposes to CaO at a temperature of 1076°F.[59] Since the temperature in the feed chute is 1900 to 2000°F, the hydrated lime will decompose at this location. There is already an abundance of CaO dust at this point in the process, so any additional dry lime will not absorb additional SO_2. Prior to the fabric filter or ESP, the temperature is less than 500°F, which is too low for any substantial reaction between dry $Ca(OH)_2$ and SO_2 to occur.
Lime Spray Drying FGD	Lime spray drying FGD would spray lime in addition to that inherently present in the exhaust stream, so that the lime could absorb the SO_2 in the exhaust. There is already an abundance of lime product in the process. Additional dry lime will not absorb additional SO_2. Injecting additional lime in the transfer chute to control SO_2 is redundant with control already achieved through inherent dry scrubbing of SO_2 and the lime product.
Increased Oxygen Levels at the Burner	The required increase in O_2 levels for implementation of this technology results in additional sulfur being deposited in the lime product, which can potentially compromise product quality. Further, increased O_2 levels near the burner would lead to additional fuel and thermal NO_X formation.

[59] Chemical Lime Company Material Safety Data Sheet, Calcium Hydroxide

APPENDIX F. ACRONYMS/ABBREVIATIONS

BART	Best Available Retrofit Technology
CaO	Calcium Oxide
CO	Carbon Monoxide
dv	Deciview(s)
Ecology	Washington State Department of Ecology
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
F	Fahrenheit
FGD	Flue Gas Desulfurization
MACT	Maximum Available Control Technology
NDCE	Non-Direct Contact Evaporator
NO_X	Nitrogen Oxides
O_2	Sulfur Dioxide
OCC	Old Corrugated Container
PM	Particulate Matter
ppm	Parts per million
PTPC	Port Townsend Paper Corporation
PTPC Mill	Port Townsend Paper Corporation Kraft Pulp and Paper Mill
PSD	Prevention of Significant Deterioration
RFO	Recycled Fuel Oil
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
tpy	Tons per year
TRS	Total Reduced Sulfur
VOCs	Volatile Organic Compounds