NOTICE OF CONSTRUCTION APPLICATION
PORT TOWNSEND MILL

COGENERATION PROJECT

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May 2010

Project 104801.0009

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1. INTRODUCTION

Port Townsend Paper Corporation (PTPC) owns and operates a Kraft pulp and paper mill located in Port Townsend, Washington (Port Townsend Mill). The Port Townsend Mill is an existing major source under the Prevention of Significant Deterioration (PSD) permitting program, and currently operates under Air Operating Permit 000092-2 issued by the Washington Department of Ecology (Ecology) on January 17, 2007 and reissued on April 28, 2010.

PTPC has formed a partnership with Sterling Energy Assets (SEA) in order to produce green electricity that will be sold to the power distribution system. PTPC and SEA are proposing a project (cogeneration project) to install a new steam turbine generator that will extract steam from the Power Boiler 10 and the Recovery Furnace, and then supply the necessary steam to the PTPC mill in order to support mill operations as well. The steam turbine will generate less than 25 MW of electricity that will be sold to a power distribution system. In order to extract steam from the Power Boiler 10 and the Recovery Furnace, specific changes will be made to each emission unit. The Power Boiler 10 will primarily use wood fuel to generate any additional steam supplied to the new steam turbine.

PTPC is proposing to upgrade the Power Boiler 10 with a new overfire air system to increase firing efficiency with wood fuel and to allow the boiler to achieve its maximum continuous rating of 250,000 lbs per hr steam while firing wood alone. After the project, the Power Boiler 10 will have a maximum firing rate of 414 MMBtu per hour. The boiler will be upgraded to increase the superheater outlet steam to 600 psig and 750 deg F. ID and FD fans and feedwater pumps would be upgraded. It should be noted that any increase in steam generated from the Power Boiler 10 will not affect the production capabilities of other units at the Port Townsend Mill (that is, an increase in pulp production will not occur as a result of the proposed project).

A new dry electrostatic precipitator (ESP) and selective non-catalytic reduction (SNCR) system will be installed on the Power Boiler 10 to control particulate matter (PM) and nitrogen oxide (NO_x) emissions, respectively. Caustic solution will be added to the existing Power Boiler 10 scrubber liquor to increase the efficiency of sulfur dioxide (SO_2) removal from the exhaust stream. Due to the addition of these control devices, the Power Boiler 10 will experience emissions decreases in PM, NO_x, and SO_2 on a short term (lb/hr) and long term (tpy) basis. PTPC expects the Power Boiler 10 to have emission increases in both volatile organic compounds (VOCs) and carbon monoxide (CO) emissions.

Additionally, the cogeneration project will involve installation of a modified solid fuel handling system for the Power Boiler 10. The solid fuel handling system will be modified such that the solid fuel is transported to the boiler in a more direct route. Note that the solid fuel handling system will have fewer components than the existing solid fuel handling system, but there will be new components added and existing components will be removed. There will also be two new solid fuel storage piles added to the Port Townsend Mill. A new haul road route will be utilized following the project to allow hog fuel to be transported from the existing barge unloading system to the existing hog fuel storage pile via truck. Currently, hog fuel is transported from the barge unloading system to the hog fuel pile via the existing chip reclaim system. A new cooling tower will be added to support the steam turbine operations. There will be an increase in PM emissions from the solid fuel handling system, the two new solid fuel storage piles, the new haul road route, and the new cooling tower.

The existing Recovery Furnace at the mill will be physically changed as a result of the cogeneration project, but emissions from the Recovery Furnace are not expected to increase. Additional superheater tubes will be added to the Recovery Furnace; these tubes will allow the Recovery Furnace to produce steam at a higher pressure. Because the capacity of the Recovery Furnace is not changing and the amount of black liquor available for combustion will remain the same, the Recovery Furnace will actually produce less steam following the completion of the cogeneration project because it will take more energy to produce the same quantity of steam at a higher temperature. This higher temperature will allow the new turbine generator to produce electricity more efficiently than if it was at the lower temperature. This modification to the Recovery Furnace will have no impact on the throughput of the unit nor will it affect the quantity of emissions that are expected to be emitted. The Recovery Furnace firing rate is tied to black liquor generated by the mill, which is unaffected by the project. The short term maximum and annual average emission rates of all pollutants from the Recovery Furnace will be unchanged as a result of the project.

A diagram showing the steam turbine setup in relationship to the Power Boiler 10 and the Recovery Furnace is included in Appendix A.

The Port Townsend Mill has the potential to emit greater than 100 tons per year (tpy) for at least one PSD pollutant, and is therefore classified as a major stationary source under the PSD permitting program.[1] Therefore, the proposed project would be subject to the PSD permitting program under Washington Administrative Code (WAC) 173-400-720 if the modification is a "major modification," (i.e., if the net emissions increase resulting from the modification is greater than the PSD Significant Emission Rate (SER) threshold for any regulated pollutant). Section 3 of this report provides detailed emission calculations illustrating the emission increases that occur as a result of the cogeneration project. As demonstrated in Section 3, there is an emission decrease for all pollutants except for PM, VOCs, and CO. While PM, VOCs, and CO emissions will increase as a result of the cogeneration project, the respective increase will remain below the SER, and PSD review will not be triggered for any pollutant.[2]

[1] The Port Townsend Mill falls under the designation of "Kraft pulp mill," which is identified in 40 CFR 52.21(b)(1)(i)(a) as having a PSD major source threshold of 100 tpy.

[2] The Power Boiler 10 will have a substantial decrease in PM emissions that will be much greater in magnitude than the PM increases shown in Section 3. As a netting analysis is not performed for the cogeneration project, PTPC is not taking credit for the emission decrease from the Power Boiler 10.

This application provides a detailed analysis of the air quality and regulatory issues pertinent to the proposed cogeneration project at the Port Townsend Mill and satisfies the Notice of Construction (NOC) application requirements under WAC 173-400-110. The application contents are presented as follows.

- *Section 1:* Introduction
- *Section 2:* Regulatory Applicability
- *Section 3:* PSD Analysis
- *Section 4:* Washington Toxic Air Pollutant Analysis
- *Section 5:* Best Available Control Technology Analysis

The Port Townsend Mill is located in Jefferson County, Washington, which is an attainment area for all pollutants. The following sections examine the regulatory requirements for the cogeneration project. Note that this regulatory applicability does not include the Recovery Furnace as there will not be an emissions increase at that unit for any pollutant.

2.1 NOTICE OF CONSTRUCTION APPLICABILITY

WAC 173-400-110 discusses the NOC and the Order of Approval requirements necessary for the construction of a new source. A new source, as defined in WAC 174-400-030, is "the construction or modification of a stationary source that increases the amount of any air contaminant emitted by such source …" Per WAC 173-400-030(47), a modification is defined as the following:

> *…any physical change in, or the change in the method of operation of a stationary source that increases the amount of any air contaminant emitted by such source or that results in the emissions of any air contaminant not previously emitted. The term modification shall be construed consistent with the definition of modification in Section 7411, Title 42, United States Code.*

The Power Boiler 10 is the only emission source that meets this definition of being modified as a result of the cogeneration project. Even though the Power Boiler 10 wood firing capacity is increasing, the emissions of PM, NO_x and SO_2 will not increase as a result of this project due to the addition of a new ESP, SNCR, and adding caustic solution to the existing scrubber. Additionally, SO_2 emissions will be further reduced to the decreased amount of oil that will be combusted in the Power Boiler 10, post project. The emissions reduction from the proposed control devices is greater than the increased capacity the Power Boiler 10 will be able to achieve once the cogeneration project is complete. Therefore, the only emissions that will increase as a result of the Power Boiler 10 modifications are VOC and CO. Note that an overfire air system is being added to the Power Boiler 10 which will allow for a reduction in VOC and CO emissions on a heat input basis. However, the emissions reduction from the proposed overfire air system is not expected to fully offset the additional emissions from the increased capacity of the Power Boiler 10. Thus, NOC permitting is required for the modification to the Power Boiler 10 due to the emissions increases of VOC and CO. Please refer to Section 3 of this report for more details on the emissions increases and decreases that occur as a result of the cogeneration project.

Per WAC 173-400-114, any person proposing to replace or substantially alter the emission control technology installed on an existing stationary source shall file an NOC application with Ecology. As such, a NOC application is required for the installation of the dry ESP and SCNR that will be added to the Power Boiler 10 to control emissions of PM and NO_x.[3]

[3] A BACT analysis is not required for NOC applications that are required under WAC 173-400-114.

It should be noted that the Power Boiler 10 is the only emission unit that meets the definition of modification under 40 CFR 60.14 and WAC 173-400-030(47). According to WAC 173-400-110(3), "new source review of a modification is limited to the emission unit or units proposed to be added to an existing source or modified and the air contaminants whose emissions would increase as a result of the modification …" Although existing fugitive sources other than the Power Boiler 10 will experience associated emissions increases as a result of the cogeneration project, since these sources will not be physically modified as part of the project, and because their emission increases are solely the result of increased solid fuel throughput, these sources are not considered to be part of the modification with respect to Washington's NOC permitting.

A new cooling tower, a new solid fuel handling system, a new haul road route, and two new solid fuel storage piles will be added to the Port Townsend mill, as well. NOC permitting is required for the addition of these new sources.

To satisfy applicable NOC application requirements, the forms required by Ecology (i.e., the NOC form, the PSD Applicability form, and the State Environmental Policy Act (SEPA) Environmental Checklist) can be found in Appendix A.

2.2 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Under WAC 173-400-113(2), each new and/or modified source must employ BACT for all pollutants not previously emitted, or any pollutants for which emissions will increase as a result of the new source or modification. Short-term VOC and CO emissions from the Power Boiler 10 will increase as a result of the proposed project; additionally, the Power Boiler 10 will be physically modified. A new cooling tower, new solid fuel handling system, a new haul road route, and two new solid fuel storage piles will also be constructed as a result of the cogeneration project. As such, these units are subject to BACT. The complete BACT analysis for the proposed cogeneration project is presented in Section 5 of this report.

2.3 Prevention of Significant Deterioration (Major New Source Review)

This section addresses the applicability of major PSD permitting to the proposed cogeneration project. An emission source is subject to the PSD permitting program under WAC 173-400-720 if the new installation is either a "major modification" to an existing "major source," or is a major source unto itself. The Port Townsend Mill has the potential to emit greater than 100 tons per year (tpy) of at least one PSD pollutant, and is therefore classified as a major stationary source under the PSD permitting program.[4] Unless otherwise exempt, a physical change to or change in the method of operation of an existing major source is considered to be a major modification if the emissions increase and the net emissions increase resulting from the modification is greater than the PSD SER threshold for any regulated pollutant.

PTPC uses a structured, step-by-step procedure to evaluate PSD applicability in this analysis, in accordance with the Washington PSD regulations. This applicability analysis has two major components, completed on a pollutant-by-pollutant basis:

1. **Calculate the project emission increases.** Under the PSD regulations in 40 CFR 52.21 and WAC 173-400-720, the increase in emissions is calculated as the difference between baseline actual emissions (pre-project actual emissions from a two-year period in the ten-year time period preceding the change) and projected actual emissions.
2. **Calculate the net emission increases** by summing the project emission increases and any other increases or decreases in actual emissions that are contemporaneous and creditable. Step 2 is only performed if the project emission increases (Step 1) exceed the SER.

The cogeneration project emission increases are below the SER, as demonstrated in the detailed emission calculations in Section 3. As such, netting is not needed to demonstrate that PSD is not applicable. Because the project emission increase for all pollutants is below the PSD SER, the cogeneration project is not subject to PSD review for any pollutant.

Per WAC 173-400-720(4)(b)(iii)(C), which replaces 40 CFR 52.21(r)(6) in the federal New Source Review (NSR) rule, a project that is not a part of a major modification that has a "reasonable possibility" of resulting in a significant emissions increase is subject to the recordkeeping and reporting requirements outlined under WAC 173-400-720(4)(b)(iii)(C). The current PSD regulations in WAC 173-400-720 do not contain a definition for "reasonable possibility." Thus, the federal definition for "reasonable possibility" is used, as defined in 40 CFR 52.21(r)(6)(vi)(a) and (b):

(a) A projected actual emissions increase of at least 50 percent of the amount that is a "significant emissions increase"… for the regulated NSR pollutant; or

(b) A projected actual emissions increase that, added to the amount of emissions excluded … sums to at least 50 percent of the amount that is a "significant emissions increase"… for the regulated NSR pollutant. For a project for which a reasonable possibility occurs only within the meaning

[4] The Port Townsend Mill falls under the designation of "Kraft pulp mill," which is identified in 40 CFR 52.21(b)(1)(i)(a) as having a major source PSD threshold of 100 tpy.

of paragraph (r)(6)(vi)(b) of this section, and not also with the meaning of paragraph (r)(6)(vi)(a) of this section, then provisions (r)(6)(ii) through (v) do not apply to the project.

Because the emission increase of all pollutants is less than 50 percent of the SER as shown in Table 3-4, the cogeneration project does not have a reasonable possibility of resulting in a significant emissions increase. Thus, PTPC is not subject to the recordkeeping and reporting requirements outlined in WAC 173-400-720(4)(b)(iii)(C)(ii) through (v) for the cogeneration project.

2.4 NEW SOURCE PERFORMANCE STANDARDS (NSPS)

NSPS apply to certain types of equipment that are newly constructed, modified, or reconstructed after a given applicability date. NSPS applicability is reviewed for the Power Boiler 10, which is expected to be physically modified as a result of the cogeneration project. Because the Recovery Furnace will not have an hourly emissions increase, the physical change to the unit will not be considered a modification under NSPS. Additionally, the installation costs of the additional superheater tubes are far less than 50 percent of the cost to replace the Recovery Furnace; as such, the superheater tubes addition to the Recovery Furnace will not be considered a reconstruction under NSPS. There are no NSPS Subparts that regulate cooling towers, haul roads, solid fuel storage piles or solid fuel handling.

2.4.1 NSPS SUBPART A (GENERAL PROVISIONS)

All affected sources subject to an NSPS are also subject to the general provisions of NSPS Subpart A unless specifically excluded by the source-specific NSPS. NSPS Subpart A requires the following of facilities subject to a source-specific NSPS:

- Initial construction/reconstruction notification
- Initial startup notification
- Performance tests
- Performance test date initial notification
- General monitoring requirements
- General recordkeeping requirements
- Semiannual monitoring system and/or excess emission reports

NSPS apply to certain types of equipment that are newly constructed, modified, or reconstructed after a given applicability date. The definitions for modification and reconstruction, which are referred to in subsequent analyses for individual NSPS subparts for emission units affected by the proposed project, are defined as follows in Subpart A:

- ***Modification:*** *Any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.*

- ***Reconstruction:*** *the replacement of components of an existing facility to such an extent that: (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) It is technologically and economically feasible to meet the applicable standards set forth in this part.*

2.4.2 NSPS Subpart D (Standards of Performance for Fossil Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971)

NSPS Subpart D (Standards of Performance for Fossil Fuel Fired Steam Generators for which Construction is Commenced after August 17, 1971) provides standards of performance for fossil fuel fired steam generating units which have been constructed or modified after August 17, 1971.[5] The affected facilities under NSPS Subpart D are all fossil fuel and wood residue fired steam generating units capable of firing fossil fuel at a heat input rate of more than 250 MMBtu.

Power Boiler 10 is currently subject to NSPS Subpart D and will have a maximum heat input capacity of 414 MMBtu/hr, post project. Power Boiler 10 has the capability to combust fossil fuels only (including reprocessed fuel oil), wood only, or a mixture of fossil fuel, wood, and solid fuels. Current emission limits required by NSPS Subpart D include a PM limit of 0.10 lb/MMBtu and an average 20% opacity limit except for one 6-minute period of not more than 27% opacity per hour. Further, NSPS Subpart D limits SO_2 emissions to 0.80 lb/MMBtu when combusting liquid fossil fuels and/or wood; and NO_X emissions to 0.30 lb/MMBtu when combusting liquid fossil fuels and liquid fossil fuels and wood.[6]

The maximum hourly emission of PM, SO_2, and NO_x, from Power Boiler 10 will not increase as a result of the cogeneration project due to the installation of an ESP, increased SO_2 removal from the existing scrubber, and SNCR. The Power Boiler 10 will continue to be subject to NSPS Subpart D after the completion of the cogeneration project.

[5] 40 CFR 60.40(a), 40 CFR 60.40(c)
[6] 40 CFR 60.42(a), 40 CFR 60.43(a), 40 CFR 60.44(a)

2.4.3 NSPS Subpart D_A (Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced After September 18, 1978)

NSPS Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978) applies to electric utility steam generating units for which construction, modification, or reconstruction commenced after September 18, 1978.[7] Per the definitions in this subpart, an electric utility steam generating unit is defined as follows:

> *"any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net electrical output to any utility power distribution system for sale.*[8]"

The Power Boiler 10 will provide steam to the turbine that is designed to generate less than 25 MW of electricity. The Power Boiler 10 does not meet the definition of electric utility steam generating unit because the net electrical output is less than 25 MW, and is therefore not subject to NSPS Subpart Da.

2.4.4 NSPS Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units)

NSPS Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units) provides standards of performance for steam generating units with heat input capacities greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984.[9] The Power Boiler 10 was constructed prior to June 19, 1984 and is currently not subject to NSPS Subpart Db.

As described in NSPS Subpart A, a modification occurs when a physical change to an existing facility causes an increase in the hourly emission rates to which a standard applies. NSPS Subpart Db establishes limits for PM, SO_2, and NO_X. The maximum hourly emission of PM, SO_2, and NO_x from Power Boiler 10 will not increase as a result of the cogeneration project due to the installation of an ESP, increased SO_2 removal by the existing scrubber, and SNCR. As such, the Power Boiler 10 will not meet the definition of a modified unit. Additionally, the Power Boiler 10 will not meet the definition of a reconstructed unit as the cost to upgrade the boiler is expected to be $20.7 million and the cost to construct a comparable new facility is expected to be $60.3 million, which is less than 50 percent threshold. Therefore, the requirements of NSPS Subpart Db are not applicable to the Power Boiler 10 as construction, modification, or reconstruction did not occur after June 19, 1984.

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[7] 40 CFR 60.40Da(a)
[8] 40 CFR 60.41Da
[9] 40 CFR 60.40b(a)

2.4.5 NSPS SUBPART EB (STANDARDS OF PERFORMANCE FOR LARGE MUNICIPAL WASTE COMBUSTORS FOR WHICH CONSTRUCTION IS COMMENCED AFTER SEPTEMBER 20, 1994 OR FOR WHICH MODIFICATION OR RECONSTRUCTION IS COMMENCED AFTER JUNE 19, 1996)

NSPS Subpart Eb (Standards of Performance for Large Municipal Waste Combustors for which Construction is Commenced after September 20, 1994 or for which Modification or Reconstruction is Commenced after June 19, 1996) provides standards of performance for municipal waste combustor units with a combustion capacity greater than 250 tons per day of municipal solid waste for which construction, modification, or reconstruction is commenced after September 20, 1994. Municipal waste combustor is defined as follows:

> *"Any setting or equipment that combusts solid, liquid, or gasified municipal solid waste including, but not limited to, field erected incinerators, modular incinerators, boilers, furnaces and pyrolysis/combustion units."*

Municipal solid waste is defined as follows:

> *"household, commercial/retail, and/or institutional waste.… Institutional waste does not include used oil, sewage sludge, wood pallets, construction, renovation and demolition wastes, clean wood, industrial process or manufacturing wastes, medical waste or motor vehicles….."*

The Power Boiler 10 has the capability to combust greater than 250 tons per day of solid fuels. However, the only fuels that the Power Boiler 10 burns that might be considered municipal solid waste include industrial process materials (such as OCC rejects) or urban wood, which are excluded from the definition of solid waste in this subpart; therefore, NSPS Subpart Eb does not apply to the Power Boiler 10.[10]

2.4.6 NSPS SUBPART CCCC (STANDARDS OF PERFORMANCE FOR COMMERCIAL AND INDUSTRIAL SOLID WASTE INCINERATION UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER NOVEMBER 30, 1999 OR FOR WHICH MODIFICATION OR RECONSTRUCTION IS COMMENCED ON OR AFTER JUNE 1, 2001)

NSPS Subpart CCCC (Standards of Performance for Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001) provides standards of performance for commercial and industrial solid waste incineration (CISWI) units. Although specific parts of NSPS Subpart CCCC were voluntarily remanded by the EPA in 2001, the affected sources are still required to be in compliance with the current version of the rule until EPA publishes the updated NSPS Subpart CCCC. As the rule is currently written, commercial or industrial waste is defined as solid waste "that is combusted at any commercial or industrial facility using controlled flame combustion in an enclosed,

[10] Urban wood is combusted in the Power Boiler 10. Although urban wood is obtained from construction, renovation, and/or demolition wastes, the wood is a useable fuel for the Power Boiler 10. Also note that PTPC uses a stringent screening process regarding the type of urban wood that is combusted in the Power Boiler 10 (e.g., – no metal scraps, no treated wood, etc.).

distinct operating unit: Whose design does not provide for energy recovery…" Energy recovery is defined as "the process of recovering thermal energy from combustion for useful purposes such as steam generation or process heating."[11] As the Power Boiler 10 is designed for energy recovery and does not meet the definition of a CISWI unit, the emission unit is not subject to the current version of NSPS Subpart CCCC.

It should be noted that EPA proposed updates to NSPS Subpart CCCC on April 29, 2010. Should the Power Boiler 10 be subject to NSPS Subpart CCCC under the final rule, PTPC will comply with all applicable standards when EPA promulgates the updated rule.

2.5 NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP)

NESHAPs have been established in 40 CFR 61 and 63 to control the emissions of Hazardous Air Pollutants (HAPs). NESHAP regulations codified in 40 CFR 63 establish Maximum Achievable Control Technology (MACT) standards for specific types of equipment at qualifying facilities. MACT regulations typically apply to facilities that are major sources. Under 40 CFR 63, a major source is defined as "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP…" The Port Townsend Mill is considered a major source under the MACT standards. NESHAP applicability is reviewed for the Power Boiler 10.

2.5.1 NESHAP SUBPART A – GENERAL PROVISIONS

All affected sources under Part 63 NESHAPs are subject to the general provisions of Part 63 NESHAP Subpart A unless specifically excluded by the source-specific NESHAP. These provisions include initial notification and performance testing, recordkeeping, and monitoring requirements for all other subparts as applicable.

The definition for reconstruction, which is referred to in subsequent analyses for individual NESHAP for emission units affected by the proposed project, is defined in Subpart A.

> ***Reconstruction:*** *The replacement of components of an affected or a previously nonaffected source to such an extent that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source…*

2.5.2 NESHAP SUBPART DDDDD (NESHAP FOR BOILERS AND PROCESS HEATERS)

NESHAP Subpart DDDDD (National Emission Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters) was vacated by the D.C. Circuit Court on June 8, 2007. On April 29, 2010, EPA proposed (with final rules expected by December 16, 2010) the updated Industrial Boiler MACT for major sources. Should the Power Boiler 10 be

[11] 40 CFR 60.2265

subject to the Boiler MACT, PTPC will comply with all applicable standards when EPA promulgates the updated rule.

2.6 ACID RAIN PROGRAM

Title IV of the federal Clean Air Act establishes general provisions for affected sources and units that contribute to acid rain. An affected source is any unit that is subject to the Acid Rain Program limitations under 40 CFR 72.6.

Pursuant to 40 CFR 72.6(a), three unit types are considered to be an affected unit under the Acid Rain Program. These unit types include any unit listed in Table 1 of 40 CFR 73.10(a), any unit listed in Table 2 or 3 of 40 CFR 73.10(a), or a utility unit that meets the criteria specified in the rule. The Power Boiler 10 is not listed in Tables 1, 2, or 3. The following definitions are necessary to determine if the Power Boiler 10 falls under the definition of a utility unit:

> ***Utility unit*** *means a unit owned or operated by a utility:*
>
> > *(1) That serves a generator in any State that produces electricity for sale, or*
> >
> > *(2) That during 1985, served a generator in any State that produced electricity for sale.*
> >
> > *(3) Notwithstanding paragraphs (1) and (2) of this definition, a unit that was in operation during 1985, but did not serve a generator that produced electricity for sale during 1985, and did not commence commercial operation on or after November 15, 1990 is not a utility unit for purposes of the Acid Rain Program.*
> >
> > *(4) Notwithstanding paragraphs (1) and (2) of this definition, a unit that cogenerates steam and electricity is not a utility unit for purposes of the Acid Rain Program, unless the unit is constructed for the purpose of supplying, or commences construction after November 15, 1990 and supplies, more than one-third of its potential electrical output capacity and more than 25 MWe output to any power distribution system for sale.*
>
> ***Utility*** *means any person that sells electricity.*
>
> ***Unit*** *means a fossil fuel-fired combustion device.*

The Power Boiler 10 and steam turbine will cogenerate steam and electricity. However, because the steam turbine has a maximum design capacity of less than the 25 MWe output threshold in paragraph (4) of the “utility unit” definition, it is not considered a utility unit for purpose of the Acid Rain Program; therefore, the Power Boiler 10 and steam turbine are not subject to the Acid Rain Program requirements.

2.7 WASHINGTON STATE REGULATIONS

The Power Boiler 10, the new cooling tower, the new haul road route, the new solid fuel storage piles, and the new hog fuel handling system are, or will be, subject to various regulations established by the WAC. The emission units associated with the cogeneration project will satisfy all applicable regulations established by the WAC. Furthermore, PTPC will comply with all general emission standards, as applicable. These limits are briefly described below.

2.7.1 GENERAL STANDARDS FOR MAXIMUM EMISSIONS

PM, in quantities sufficient to impede reasonable use and enjoyment of property, may not be deposited beyond the property under the control of the owner in accordance with WAC 173-400-040(2). PTPC shall take reasonable precautions to prevent the release of air contaminants from emissions units used for material handling, construction, demolition, or other fugitive emission operations in accordance with WAC 173-400-040(3). In addition, reasonable precautions will be taken to prevent fugitive dust, per WAC 173-400-040(8).

WAC 173-400-040(1) limits opacity to 20 percent for greater than 3 minutes in any one hour, with the exceptions provided in WAC 173-400-040(1)(a) through (e). Per WAC 173-400-040, if an emission standard is listed in another chapter that applies to the Power Boiler 10, such standard will take precedent over a general emission standard listed in WAC 173-400-040. Because the Power Boiler 10 is subject to the particulate and opacity limits specified in WAC 173-405, the standards provided in WAC 173-400-040 do not apply.

SO_2 emissions from combustion sources are limited to 1,000 ppm of SO_2 on a dry basis, corrected to 7 percent oxygen, with the exceptions provided in WAC 173-400-040(6).

PTPC will use good practices and procedures to limit the generation of odors, as required in WAC 173-400-040(4). WAC 173-400-040(5) and (7) prevent facilities from emitting, concealing, or masking air contaminants which may be detrimental to health, safety, or welfare of a person, or cause damage to property and business.

2.7.2 WASHINGTON EMISSION STANDARDS FOR COMBUSTION AND INCINERATION UNITS

Standards for combustion and incineration units are established in WAC 173-400-050. Per WAC 173-400-040, if an emission standard is listed in another chapter that applies to the Power Boiler 10, such standard will take precedent over a general emission standard listed in WAC 173-400-040. Because the Power Boiler 10 is subject to the particulate and opacity limits specified in WAC 173-405, the standards provided in WAC 173-400-050 do not apply.

2.7.3 STANDARDS FOR COMMERCIAL AND INDUSTRIAL WASTE INCINERATION (CISWI) UNITS

Standards for commercial and industrial solid waste incineration (CISWI) units are provided in WAC 173-400-050(4). A CISWI unit is defined as "any combustion device that combusts commercial and industrial waste." Commercial and industrial solid waste is defined as "solid waste combusted in an enclosed device using controlled flame combustion without energy recovery…" The Power Boiler 10 does not qualify as a CISWI unit, because it employs energy recovery (in the form of steam generation) when combusting any fuel type.

2.7.4 EMISSION STANDARDS FOR HOG FUEL BOILERS

The standards for hog fuel boilers established under WAC 173-400-070(2) apply to the Power Boiler 10. WAC 173-400-070(2) requires that hog fuel boilers meet all of the provisions of WAC 173-400-040 and 173-400-050(1), except that emissions from hog fuel boilers may exceed twenty percent opacity for up to fifteen consecutive minutes once in any eight hours. This provision allows for necessary soot blowing and grate cleaning activities. Such activities must be scheduled for the same specific times each day.

In addition, all hog fuel boilers are required to use reasonably available control technology (RACT) and must be maintained to minimize emissions. Power Boiler 10 will comply with the standards presented in WAC 173-400-070(2).

2.7.5 EMISSION STANDARDS FOR KRAFT PULPING MILLS

The standards for Kraft pulp mill emissions sources are established under WAC 173-405-040. Per WAC 173-405-040(5)(a), the Power Boiler 10 is subject to the emission limit of 0.2 gr/dscf corrected to seven percent oxygen because the unit combusts wood or wood residue to produce steam and commenced construction prior to January 1, 1983. Per WAC 173-405-040(6), the Power Boiler 10 is subject to an opacity limit of twenty percent except for six consecutive minutes in any sixty minute period. This opacity provision does not apply when soot blowing and grate cleaning activities take place. Such activities must be scheduled for the same specific times each day. Note that WAC 173-405 supersedes the particulate and opacity requirements listed for emission units under WAC 173-400.

2.7.6 WASHINGTON STATE CARBON DIOXIDE MITIGATION PROGRAM

WAC 173-407-010 establishes carbon dioxide mitigation requirements for, "all new and certain modified fossil-fueled thermal electric generating facilities with station-generating capability of more than 25 megawatts of electricity (MWe)." The steam turbine installed at Power Boiler 10 will generate less than 25 MW of electricity, thus, the Power Boiler 10 and steam turbine will not subject to the requirements of WAC-173-407.

2.7.7 STANDARDS FOR SOLID WASTE INCINERATOR FACILITIES

WAC 173-434 establishes standards for the following solid waste incinerator facilities:

1. Incinerator facilities constructed after January 1, 1985, which are designed to burn twelve or more tons per day of solid waste; or
2. Incinerators facilities constructed prior to January 1, 1985, but began to burn twelve or more tons per day of solid waste after January 1, 1985.

An incinerator facility is defined as "all emissions unit(s), including quantifiable fugitive emissions which are located in one or more contiguous or adjacent properties, and are under the control of the same person(s), whose activities are principal or ancillary to the incineration of solid waste." Solid waste means "all putrescible and nonputrescible solid and semisolid wastes, including but not limited to garbage, rubbish, ashes, industrial wastes, swill, demolition and construction wastes, abandoned vehicles or parts thereof, discarded commodities, septage from septic tanks, dangerous waste, refuse derived fuel, solid waste derived fuel, problem wastes, and all materials which are not primary products of public, private, industrial, commercial, mining, and agricultural operations…. Notwithstanding the above, solid waste does not include: … (c) wood waste."

The Power Boiler 10 combusts OCC rejects and urban wood. Though PTPC considers both of these products to be usable fuel rather than solid waste, should Ecology view the materials as solid waste, the wood waste exemption included in the definition of solid waste can be claimed for both OCC rejects and urban wood. Since the material that is combusted in Power Boiler 10 does not meet the definition of solid waste referenced within WAC 173-434-030, the Power Boiler 10 is not subject to the requirements of WAC 173-434.

2.7.8 AMBIENT AIR QUALITY STANDARDS

WAC 173-470, 173-474, and 173-475 establish ambient air quality standards for PM; sulfur oxides (SO_x); and CO, ozone, and nitrogen dioxide (NO_2), respectively. The ambient air quality standards serve as the maximum acceptable levels for each pollutant in the ambient air. The proposed cogeneration project will not cause an exceedance of Washington's ambient air quality standards. The cogeneration project will result in lower overall emissions from the facility for PM and SO_2. CO emissions will increase as a result of the cogeneration project; however, it is assumed that the cogeneration project will not cause an exceedance of the CO ambient air quality standards, as the hourly emission increase is well below the CO small quantity emission rate (SQER) listed in WAC 173-460, as demonstrated in Section 4 of this report.

2.8 WASHINGTON TOXIC AIR POLLUTANTS REGULATIONS

In Washington, all new sources emitting Toxic Air Pollutants (TAPs) are required to show compliance with the Washington TAP program pursuant to WAC 173-460. Ecology has established a *de minimis* level, a SQER, and an Acceptable Source Impact Level (ASIL) for each listed TAP.[12] An *acceptable source impact analysis* must be conducted for each TAP with an emission increase greater than the *de minimis* level.[13] If the TAP emissions rate from a source is above its respective SQER, further determination of compliance with the ASIL is required. A complete TAP analysis is included in Section 4 of this report. The required BACT analysis for toxics (tBACT) is presented in Section 5 of this report.

[12] De minimis levels, SQERs, and ASILs are provided for each TAP in WAC 173-460-150.

[13] The acceptable source impact analysis methodology is outlined in WAC 173-460-080. The definition can be found in WAC 173-460-020(1).

3. PSD ANALYSIS

This section addresses the applicability of PSD permitting to the proposed cogeneration project. An emission source is subject to the PSD permitting program under WAC 173-400-700 through WAC 173-400-750 if the new installation is either a "major modification" to an existing "major source," or is a major source unto itself. The Port Townsend Mill has the potential to emit greater than 100 tons per year (tpy) of at least one PSD pollutant, and is therefore classified as a major stationary source under the PSD permitting program.[14] Unless otherwise exempt, a physical change in, or change in the method of operation of an existing major source is considered to be a major modification if the emission increase and the net emissions increase resulting from the modification is greater than the PSD SER threshold for the respective regulated pollutant. PTPC uses a structured, step-by-step procedure to evaluate PSD applicability in this analysis, in accordance with Washington and federal PSD regulations.

The following procedure is used to determine if a major modification will occur as a result of the proposed cogeneration project:

1. **Calculate emission increases from the project alone**: Under the PSD regulations in 40 CFR 52.21 and WAC 173-400, the increase in net annual emissions is calculated for new emission units, existing physically modified emission units, and existing emission units that will have an associated increase in throughput but will not be physically modified. The increase in emissions for modified units is calculated as the difference between the projected actual emissions and the baseline actual emissions. If the emission increase from the project alone is less than the SER for a pollutant, then PSD permitting is not triggered for that particular pollutant.
2. **Calculate net contemporaneous and creditable emission increases and decreases**: For all pollutants that will have emissions increases greater than the SER when just looking at the project increase, a further analysis is used to determine the contemporaneous and creditable emissions increases that occurred during the five year period prior to the date of this application. Step 2 is only performed if the project emission increases exceed the SER. As the cogeneration project emission increases are below the SER, Step 2 is not necessary and a netting analysis is not included with the PSD applicability determination.

3.1 LIST OF PSD POLLUTANTS

The current list of regulated NSR pollutants was published in the preamble to the NSR Reform final rule on December 31, 2002. The preamble confirms that mercury and other hazardous air pollutants listed under section 112(b)(1) are no longer regulated under the NSR program, although these pollutants were regulated under PSD historically. Table 3-1 shows the NSR regulated pollutants, their respective SER, and whether the pollutant is expected to be emitted from the project.

[14] The Port Townsend mill falls under the designation of "Kraft pulp mill," which is identified in 40 CFR 52.21(b)(1)(i)(a) as having a major source PSD threshold of 100 tpy.

TABLE 3-1. NSR REGULATED POLLUTANTS

Regulated NSR Pollutants	Expected from Project?	Significant Emission Rate [a] (tpy)
Criteria Pollutants		
$PM_{2.5}$	Yes	10 (or 40 tpy NO_x or SO_2)
PM_{10}	Yes	15
Particulate Matter	Yes	25
Sulfur Dioxide	Yes	40
Oxides of Nitrogen	Yes	40
Ozone (VOC)	Yes	40
Carbon Monoxide	Yes	100
Lead (elemental)	Not Expected [b]	0.6
Other Pollutants		
Fluorides (except HF)	Not Expected [b]	3
Sulfuric Acid Mist	Yes	7
Hydrogen Sulfide	Yes	10
Total Reduced Sulfur Compounds	Yes	10
CFCs and Halons	No	Any
Municipal Waste Combustor (MWC) acid gases [c]	No	40
MWC metals [d]	No	15
MWC organics [e]	No	3.5e-6
Municipal Solid Waste Landfill Emissions [f]	No	50

[a] The significant emission rate of each pollutant is established under 40 CFR 52.21(b)(23)(i).
[b] The emissions of elemental lead and fluorides (except HF) are discussed in more detail in the following sections of this report.
[c] MWC acid gases are measured as sulfur dioxide and hydrogen chloride.
[d] MWC metals are measured as PM.
[e] MWC organics are measured as total tetra-through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.
[f] Municipal solid waste landfill emissions are measured as nonmethane organic compounds.

3.1.1 LEAD

EPA promulgated NAAQS for lead under CAA Section 109 on October 5, 1978.[15] Thus, lead is potentially an NSR-regulated pollutant. In the 1990 CAAA, Congress included *lead compounds* on the 112(b)(1) list. Congress also included a specific exemption for one type of lead from being regulated under NESHAP, at Section 112(b)(7).

> *(7) LEAD.—The Administrator may not list elemental lead as a hazardous air pollutant under this subsection.*

[15] 43 FR 46246.

Thus, while lead in general has a NAAQS, only non-elemental lead is regulated under NESHAP, leaving elemental lead subject to regulation under the NSR program. EPA has considered lead emitted from most industrial processes to be emitted as lead compounds.

> *… based on our understanding of Lead chemistry, we assume that for most industrial processes, most of the Lead is emitted as Lead compounds; specifically, Lead Oxides, Lead Chlorides, Lead Sulfites, and Lead Sulfates.*[16]

Thus, PTPC believes that most or all of the lead emitted from the project will be non-elemental lead, and not subject to PSD review. As such, for the purpose of PSD applicability and emissions estimates, it is assumed that lead is emitted in non-elemental form and not subject to PSD review.

3.1.2 FLUORIDES

Fluorides in general are regulated under PSD. However, since hydrogen fluoride (HF) is included on the 112(b)(1) list, emissions of HF are not regulated via PSD. Thus, the regulated NSR pollutant related to fluorine is fluorides except HF.

The basis for the fluoride SER of 3 tpy is explained in the preamble to the 1980 PSD regulations (45FR52709). The rate is based on the NSPS for aluminum plants, adjusted to limit the potential for effects on vegetation near an aluminum plant. The NSPS for aluminum plants is Subpart S, and 40 CFR 60.191 defines the fluorine compounds regulated.

> *Total fluorides means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.195 …*

For combustion sources, most of the fluorine compounds emitted are expected to be in the form of HF, which is not regulated under PSD. As such, for the purposes of PSD applicability and emissions estimates, it is assumed that fluorine is only emitted as HF, and is not subject to PSD review.

3.2 AGGREGATION

In a PSD applicability analysis, the term "aggregation" describes the process of grouping related physical or operational changes into a single project for evaluating PSD applicability. When undertaking multiple changes at a facility, it is important to consider whether PSD applicability should be determined collectively or whether emissions from each group of projects should be treated separate under PSD analysis. One unrelated change, the addition of the improved process controls project at the mill, will occur before the cogeneration project and will affect the Power Boiler 10. PTPC considers the improved process controls project to be an unrelated change as described in the April 14, 2010 correspondence with Ecology concerning that change. The emissions change from the improved process controls project, however, are included in the PSD applicability emission

[16] EPA memorandum from John Seitz (Director, OAQPS) to EPA Regions, "Guidance on the Major Source Determination for Certain Hazardous Air Pollutants", August 14, 2000. A copy is available at http://www.epa.gov/ttn/atw/agghapsmemo3.html.

calculations for the cogeneration project, since the baseline period used in the calculations for each pollutant is from a period prior to the improved process controls project. No other projects have occurred over the past five years which resulted in an increase in emissions at the Port Townsend mill. Additionally, there are no additional related projects planned for the near future. Therefore, aggregation with other previous or future projects does not need to be considered for the cogeneration project.

3.3 EMISSION UNITS WHERE EMISSION INCREASES WILL OCCUR

The proposed project will result in an overall increase in emissions of total suspended particulate (TSP), particulate matter with a diameter less than 10 micron (PM_{10}), particulate matter with a diameter less than 2.5 micron ($PM_{2.5}$), CO, and VOCs. The proposed project will not result in an overall increase in emissions of SO_2, NO_x, total reduced sulfur (TRS), hydrogen sulfide (H_2S), and sulfuric acid mist (H_2SO_4). Emission increase calculation methodologies are presented in the subsequent sections for each affected source.

The existing Power Boiler 10 and the Recovery Furnace will undergo physical modifications. A new cooling tower, a new solid fuel handling system, a new haul road route, and two new solid fuel storage piles will be installed with the project. Fugitive emission sources, including solid fuel handling systems, haul roads, and solid fuel storage piles, will also be affected by the project. Changes affecting emissions at fugitive emission sources are described below:

- **Existing Barge Unloading System:** The existing barge unloading system will continue to operate following the project and the throughput of hog fuel received by barge will increase as the result of the project. Therefore, the barge unloading system will experience an emission increase as a result of the project.
- **Existing/New Solid Fuel Handling System:** A portion of the existing Power Boiler 10 solid fuel handling system will be replaced with the cogeneration project. A new truck dumper and transfer system from the truck dump to the Power Boiler 10 building will be installed with the project. This new portion of the solid fuel handling system will be a new fugitive emission source. In the new solid fuel handling system, hog fuel, OCC rejects, sludge, sawdust, and chips are dumped onto the hog fuel pile at the truck dump. From this point, solid fuel is transferred to the biomass reclaim conveyor via a loader. Solid fuel is transferred from the biomass reclaim conveyor to the biomass belt conveyor to a scale and biomass sorter located under a canopy. From here, solid fuel is transferred to biomass belt conveyor #2 to biomass belt conveyor #3. From biomass belt conveyor #3, solid fuel will be transported to the Power Boiler 10 using the existing solid fuel handling system located inside the Power Boiler 10 building. The portion of the existing solid fuel handling system located inside the Power Boiler 10 building will continue to be used following the project. As the solid fuel throughput to the Power Boiler 10 will increase as a result of the project, an associated emission increase will be experienced by the portion of the existing solid fuel handling system inside the boiler building.
- **Hog Fuel Haul Roads:** Currently, hog fuel is transported from the barge unloading system to the hog fuel pile and from off-site to the hog fuel pile. Hog fuel is transferred from the barge unloading system to the hog fuel storage pile via the chip reclaim system. Hog fuel is transferred from offsite to the hog fuel pile via trucks. As a result of the project, the throughput of hog fuel received both by barge and by truck from off-site will increase. Additionally, hog fuel received

by barge will not be transported via the existing chip reclaim system, but will instead be transported by truck to the hog fuel storage pile. Therefore, a new haul road route will be established from the barge unloading system to the hog fuel storage pile. The number of trips traveled along the existing hog fuel truck route from offsite will increase with the project. Emissions produced by the hog fuel trucks will also increase as a result of the project.

- **Fly Ash Haul Roads:** Currently, fly ash is transported from the fly ash bunker to a landfill on PTPC's property by front-end loader. Following the project, fly ash will be transported from the fly ash bunker to the landfill by truck. The total throughput of fly ash produced by the Power Boiler 10 will increase as a result of the project. As trucks are capable of handling larger loads than the front end loaders currently used at the mill, the number of trips along the fly ash haul road route will actually decrease as a result of the project.
- **Storage Piles:** The existing hog fuel storage pile will increase in size as a result of the project. Therefore, emissions from the hog fuel storage pile will increase as a result of the project. Two new storage piles, including an urban wood storage pile and a forest waste storage pile, will be created as a result of the project. These two new solid fuel storage piles will be new fugitive emission sources.

No other emission sources will be modified or added to the Port Townsend Mill as a result of the cogeneration project. The following sections provide the methodology used to calculate project increases from the units affected by the project.

3.4 BASELINE ACTUAL EMISSIONS

The term "baseline actual emissions" is defined in 40 CFR 52.21(b)(48)(ii) for existing emission units that are not electric utility steam generating units as:

> *…the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Administrator for a permit required under this section or by the reviewing authority for a permit required by a plan, whichever is earlier…*

Baseline actual emissions are calculated for existing emission units where an increase in emissions will occur as a result of the cogeneration project, either as the result of a physical modification to the unit or as the result of an associated emission increase. Such emission units include the Power Boiler 10, the Recovery Furnace, and several fugitive emission sources. Baseline emission calculation methodologies are discussed in the following sections.

3.4.1 POWER BOILER 10

For the Power Boiler 10, the baseline actual emissions are obtained from annual emission inventories prepared by PTPC from 2004 to 2009.[17] These emissions are based on the following information:

- TSP, PM_{10}, and $PM_{2.5}$ emissions from the Power Boiler 10 are determined using the results of Method 5 source testing conducted at the frequency required by the facility's Air Operating Permit, and the corresponding annual heat input. Per 40 CFR 52.21(b)(48)(ii)(c), the average emission rate shall be adjusted downward to exclude any emissions that exceed an emission limit. The Power Boiler 10 is subject to a 0.10 lb PM/MMBtu emission factor, which was periodically exceeded during the baseline time period. Accordingly, the average emission rate was adjusted downward to reflect the permitted emission factor for those months of data where PM emissions exceed the limit.
- SO_2 emissions from the Power Boiler 10 are determined using the results of source testing conducted at the frequency required by the facility's Air Operating Permit, and the corresponding annual heat input. The Power Boiler 10 periodically fires Non-Condensible Gases (NCGs) throughout the year in addition to various fuels. Stack test information is not available to estimate the effects NCG firing has on SO_2 emissions, but SO_2 emissions from the firing of NCGs in the Power Boiler 10 must be accounted for in the baseline SO_2 emission estimate. The NCG SO_2 concentration is estimated based on a 2001 study performed by PTPC on the NCG effects on SO_2 emissions. As such, SO_2 emissions resulting from the firing of NCGs in the Power Boiler 10 are estimated and added to the SO_2 emissions calculated from the firing of other various fuels using stack test results.
- NO_x emissions from the Power Boiler 10 are determined by a continuous emission monitoring system (CEMS).
- VOC emissions from the Power Boiler 10 are determined using emission factors and the corresponding heat input.[18]
- CO emissions from the Power Boiler 10 are determined using standard emission factors and the corresponding heat input.[19]
- TRS emissions from the Power Boiler 10 are determined by applying the results of source testing conducted at the frequency required by the facility's Air Operating Permit to the exhaust flow rates and hours of operation of the boiler.
- For the purposes of calculating H_2S emissions from the Power Boiler 10, it is assumed that all TRS is emitted as H_2S.
- H_2SO_4 emissions are calculated by assuming that 5 percent of SO_2 baseline emissions from the Power Boiler 10 are converted to H_2SO_4 emissions in the atmosphere or flue gas. This estimation methodology is based on available data for H_2SO_4 emissions from

[17] For a project that involves multiple emission units, only one consecutive 24-month period may be used to determine the actual baseline emissions, but different 24-month periods can be used for different pollutants, in accordance with 40 CFR 52.21(b)(48)(ii)(d).

[18] AP-42 emission factors as listed in AP-42 Table 1.6-3 (9/2003) for wood fuel and Table 1.3-3 (9/1998) for oil fuel.

[19] AP-42 emission factors as listed in AP-42 Table 1.6-2 (9/2003) for wood fuel and Table 1.3-1 (9/1998) for oil fuel.

burning fuel oil, as data for H_2SO_4 emissions from burning hog fuel is not readily available.[20]

- The cogeneration project will not affect the startup, shutdown, and malfunction (SSM) emissions expected from the boiler. As such, these emissions are not included in either the baseline emissions or the projected actual emissions from the Power Boiler 10.

3.4.2 RECOVERY FURNACE

For the Recovery Furnace, the baseline actual emissions are obtained from annual emission inventories prepared by PTPC from 2004 to 2009.[21] These emissions are based on the following information:

- TSP, PM_{10}, and $PM_{2.5}$ emissions from the Recovery Furnace are determined using the results of Method 5 source testing conducted at the frequency required by the facility's Air Operating Permit, and the corresponding annual heat input.
- SO_2 emissions from the Recovery Furnace are determined using the results of source testing conducted at the frequency required by the facility's Air Operating Permit, and the corresponding annual heat input.
- NO_x emissions from the Recovery Furnace are based on black liquor solids (BLS) firing rates as monitored by PTPC, and NCASI emissions factors as listed in NCASI Technical Bulletin 884, Table 4.12 (8/2004) for NDCE Kraft recovery furnaces.
- VOC emissions from the Recovery Furnace are based on BLS firing rates as monitored by PTPC, and NCASI emissions factors as listed in NCASI Technical Bulletin 884, Table 4.12 (8/2004) for NDCE Kraft recovery furnaces.
- CO emissions from the Recovery Furnace are based on BLS firing rates as monitored by PTPC, and NCASI emissions factors as listed in NCASI Technical Bulletin 884, Table 4.12 (8/2004) for NDCE Kraft recovery furnaces.
- TRS emissions from the Recovery Furnace are determined by CEMs.
- For the purposes of calculating H_2S emissions from the Recovery Furnace, it is assumed that all TRS is emitted as H_2S.
- H_2SO_4 emissions from the Recovery Furnace are based on BLS firing rates as monitored by PTPC, and NCASI emission factors as listed in NCASI Technical Bulletin 973, Table 4.23 (2/2010) for NDCE Kraft recovery furnaces.
- The cogeneration project will not affect the SSM emissions expected from the Recovery Furnace. As such, these emissions are not included in either the baseline emissions or the projected actual emissions from the Recovery Furnace.

3.4.3 FUGITIVE EMISSION SOURCES

Baseline actual fugitive emissions are calculated for existing fugitive emission sources that are affected by the cogeneration project. Such fugitive sources include the existing barge hog fuel unloading system, the solid fuel handling system located inside the Power Boiler 10 building, hog fuel truck routes, fly ash truck routes, and the hog fuel storage pile. Baseline

[20] Per AP-42 Chapter 1.3, Section 1.3.3.2.

[21] For a project that involves multiple emission units, only one consecutive 24-month period may be used to determine the actual baseline emissions, but different 24-month periods can be used for different pollutants, in accordance with 40 CFR 52.21(b)(48)(ii)(d).

actual emissions for each fugitive emission source are calculated using the following methodology:

- **Barge Unloading System**: Currently, approximately 5% of the hog fuel fired in the Power Boiler 10 is received by barge. Baseline actual emissions are quantified using the equation for PM generated by drop operations established in AP-42, Section 13.2.4 (Aggregate Handling and Storage Piles) and the actual hog fuel throughput received by barge during 2009.
- **Existing Solid Fuel Handling System**: Baseline actual emissions from the existing solid fuel handling system are quantified using the equation for PM generated by drop operations established in AP-42, Section 13.2.4 (Aggregate Handling and Storage Piles). The baseline throughput of solid fuel is based on the 24-month annual average solid fuel throughput fired in the Power Boiler 10 during the baseline period selected for TSP/PM_{10}/$PM_{2.5}$.
- **Hog Fuel Haul Roads**: In the baseline period, the route from off-site to the hog fuel pile is paved. Baseline actual emissions from paved roads are calculated using the proposed revisions to AP-42 Section 13.2.1.[22] Baseline number of annual trips for the hog fuel truck route is calculated based on the baseline hog fuel throughputs and the amount of material contained in each load, based on standard truck specifications.
- **Fly Ash Haul Roads**: In the baseline period, the route from the ash bunker to the landfill is partially paved and partially unpaved. Baseline actual emissions from unpaved roads are calculating using the methodology found in AP-42 Section 13.2.2. Baseline actual emissions from paved roads are calculated using the proposed revisions to AP-42 Section 13.2.1.[23] Baseline number of annual trips for the fly ash route is based on annual solid waste reports submitted by PTPC.
- **Hog Fuel Storage Pile**: Baseline emissions from the hog fuel storage pile are calculated using the methodology outlined in EPA's *Control of Open Fugitive Dust Emission Sources*, Section 4.1.3.[24] The baseline footprint of the storage pile is estimated at 1.03 acres.

A 24-month period between 2004 and 2009 is selected as the baseline period for each pollutant. Baseline emissions are provided as the average annual emission rate during the 24-month baseline period. No new emission limits have been established since 2004. Likewise, no new pollution control requirements have been established since 2004. Therefore, no baseline actual emissions are required to be adjusted downward because of currently applicable emission limits or pollution control equipment requirements.[25]

Particulate emissions from the Power Boiler 10 occasionally exceeded the 0.1 lb PM/MMBtu emission limit established in the facility's current operating permit. In instances when the permitted limit was exceeded, baseline actual emissions of TSP, PM_{10}, and $PM_{2.5}$ are determined using the actual permit limit (0.1 lb PM/MMBtu) and the monthly heat input.[26] No other permitted emission

[22] http://www.epa.gov/ttn/chief/ap42/ch13/draft/proposedrevisonsto_c13s0201.pdf
[23] http://www.epa.gov/ttn/chief/ap42/ch13/draft/proposedrevisonsto_c13s0201.pdf
[24] EPA-450/3-88-008, dated September 1988
[25] 40 CFR 52.21(b)(48)(ii)(c)
[26] 40 CFR 52.21(b)(48)(ii)(b)

limits were exceeded during the baseline period for any of the emission units affected by the project. A summary of the baseline actual emissions for each pollutant from the units affected by the project is provided in Table 3-2 below.

TABLE 3-2. BASELINE ACTUAL EMISSIONS

	TSP (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)	TRS (tpy)	H_2S (tpy)	H_2SO_4 (tpy)
Baseline Period	*12/04 – 11/06*			*01/08 - 12/09*	*11/04 – 10/06*	*08/04 – 07/06*	*11/04 – 10/06*	*05/05 – 04/07*	*05/05 – 04/07*	*01/08 – 12/09*
Power Boiler 10	103.12	103.12	103.12	98.04	263.87	591.49	17.02	1.22	1.22	7.43
Recovery Furnace	146.89	146.89	146.89	7.88	258.65	207.05	15.53	1.63	1.63	4.56
Cooling Tower	--	--	--	--	--	--	--	--	--	--
Solid Fuel Handling Fugitives	0.002	0.001	0.0001	--	--	--	--	--	--	--
Hog Fuel Haul Road Fugitives	0.26	0.05	0.01	--	--	--	--	--	--	--
Storage Pile Fugitives	0.80	0.40	0.40	--	--	--	--	--	--	--
Fly Ash Haul Road Fugitives	4.15	1.18	0.12	--	--	--	--	--	--	--
Total Emissions	**255.22**	**251.64**	**250.54**	**105.92**	**522.65**	**798.54**	**32.54**	**2.86**	**2.86**	**11.99**

Additional details for determining the baseline emissions for each respective pollutant are provided in Appendix B.

3.5 PROJECTED ACTUAL EMISSIONS

The term "*projected actual emissions*" is defined in 40 CFR 52.21(b)(41)(i) as:

> *…the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emission unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.*

Projected actual emissions are calculated for existing emission units which are affected by the cogeneration project as well as new emission units to be installed with the project. Such emission units include the Power Boiler 10, the Recovery Furnace, the cooling tower, and several fugitive emission sources. Projected actual emission calculation methodologies are discussed in the following sections. It should be noted that the projected actual emissions were not adjusted to account for any emissions the Power Boiler 10 or the Recovery Furnace could have accommodated during the baseline period.[27]

3.5.1 POWER BOILER 10

The Power Boiler 10 will be physically modified as a part of the project. Following the modification, the boiler will have a maximum firing rate of 414 MMBtu/hr. It is assumed that the Power Boiler 10 will operate 365 days per year. Projected actual emission factors for each criteria pollutant are based on design data, which account for additional control devices to be installed on the Power Boiler 10 with the project. The proposed project will increase emissions of VOC s and CO from the Power Boiler 10. The proposed project will result in a decrease in emissions of TSP, PM_{10}, $PM_{2.5}$, SO_2, NO_x, TRS, H_2S, and H_2SO_4 from the Power Boiler 10. The cogeneration project will not affect the SSM emissions expected from the Power Boiler 10. As such, these emissions are not included in either the baseline emissions or the projected actual emissions from the Power Boiler 10.

3.5.2 RECOVERY FURNACE

The Recovery Furnace will be physically modified as a part of the project. Following the modification, the Recovery Furnace will operate exactly the same as during the baseline period except that unit will have additional superheater tubes. Projected actual emissions are thus set equal to the emissions calculated during the baseline period, as PTPC projects that the throughput and the emissions profile will be the unchanged following the cogeneration project. The cogeneration project will not affect the SSM emissions expected from the Recovery Furnace. As such, these emissions are not included in either the baseline emissions or the projected actual emissions from the Recovery Furnace.

3.5.3 COOLING TOWER SYSTEM

A new cooling tower system will be installed with the project, consisting of two cells, each with its own fan. The cooling tower system will have a design water recirculation rate of 12,000 gallons per minute and the circulating water will have a total dissolved solids (TDS) of 5,000 ppm. The cooling tower system will be equipped with mist eliminators with a drift rate of 0.001% and will not use any water treatment chemicals that contain HAPs or TAPs. PM emissions are based on the maximum cooling tower design parameters, and thus represent potential emission from this emission source.

3.5.4 FUGITIVE EMISSION SOURCES

Projected actual fugitive emissions are calculated for existing fugitive emission sources affected by the project as well as new fugitive emission sources installed with the project. Projected actual emissions for each fugitive emission source are calculated based on the following information:

- **Barge Unloading System**: Following the project, approximately 10 to 20% of the hog fuel fired in the Power Boiler 10 will be received by barge. The throughput of hog fuel

[27] 40 CFR 52.21(b)(41)(ii)(c)

received by barge will increase as a result of the project; therefore, the barge unloading system will experience an associated emission increase. Projected actual emissions are quantified using the equation for PM generated by drop operations established in AP-42, Section 13.2.4 (Aggregate Handling and Storage Piles) and the projected actual throughput of hog fuel that will be received by barge following the project.

- **Solid Fuel Handling System**: A new hog fuel handling system will be installed to feed hog fuel to the Power Boiler 10. The portion of the existing solid fuel handling system located inside the Power Boiler 10 will continue to be used following the project. Projected actual emissions from the solid fuel handling system are quantified using the equation for PM generated by drop operations established in AP-42, Section 13.2.4 (Aggregate Handling and Storage Piles). The projected actual solid fuel throughput is based on the post-project maximum firing rate of 414 MMBtu/hr at the Power Boiler 10.
- **Hog Fuel Haul Roads**: Following the project, hog fuel trucks will travel additional trips over a year on the existing route. Also, hog fuel trucks will travel on a new route from the barge unloading system to the hog fuel storage pile. This new route will be unpaved. Hog fuel trucks will continue to travel on paved roads from off-site to the truck dumper. Projected actual emissions from paved roads are calculated using the proposed revisions to AP-42 Section 13.2.1.[28] Projected actual emissions from unpaved roads are calculating using the methodology found in AP-42 Section 13.2.2. The number of annual trips following the project is calculated using post-project hog fuel throughputs and the amount of hog fuel contained in each load, based on standard truck specifications.
- **Fly Ash Haul Roads**: Following the project, trucks will replace front-end loaders and the amount of fly ash generated by the Power Boiler 10 will increase. Although the total throughput of fly ash transported to the landfill will increase, the total number of trips will decrease due to the increased load size per vehicle. The same route will be used to transport fly ash, and will continue to be partially paved and partially unpaved. Projected actual emissions from paved roads are calculated using the proposed revisions to AP-42 Section 13.2.1.[29] Projected actual emissions from unpaved roads are calculating using the methodology found in AP-42 Section 13.2.2. The number of annual trips following the project is calculated using post-project fly ash throughput and the amount of fly ash contained in each load, based on standard truck specifications.
- **Hog Fuel Storage Pile**: Following the project, the hog fuel pile will remain in the same location but will increase in size to accommodate the larger hog fuel throughput of the Power Boiler 10. Projected actual storage pile emission calculations are calculated using the methodology outlined in EPA's *Control of Open Fugitive Dust Emission Sources*, Section 4.1.3.[30] The post-project footprint of the storage pile is expected to be 1.10 acres as a result of the project.
- **New Urban Wood Pile and New Forest Waste Pile**: Two new solid fuel storage piles will be installed with the project for the storage of urban wood and forest waste. Storage pile emission calculations are calculated using the methodology outlined in EPA's *Control of Open Fugitive Dust Emission Sources*, Section 4.1.3.[31] The footprint of each new storage pile is expected to be 0.52 acres.

[28] http://www.epa.gov/ttn/chief/ap42/ch13/draft/proposedrevisonsto_c13s0201.pdf
[29] http://www.epa.gov/ttn/chief/ap42/ch13/draft/proposedrevisonsto_c13s0201.pdf
[30] EPA-450/3-88-008, dated September 1988
[31] EPA-450/3-88-008, dated September 1988

The projected actual throughput and projected actual emissions from each emission unit are presented in Table 3-3.

TABLE 3-3. PROJECTED ACTUAL EMISSIONS

	TSP (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)	TRS (tpy)	H_2S (tpy)	H_2SO_4 (tpy)
Power Boiler 10	27.20	27.20	27.20	72.53	235.73	634.66	18.13	0.45	0.45	1.72
Recovery Furnace	146.89	146.89	146.89	7.88	258.65	207.05	15.53	1.63	1.63	4.56
Cooling Tower	1.32	1.32	1.32	--	--	--	--	--	--	--
Solid Fuel Handling Fugitives	0.06	0.03	0.004	--	--	--	--	--	--	--
Hog Fuel Haul Road Fugitives	5.01	1.37	0.14	--	--	--	--	--	--	--
Storage Pile Fugitives	1.65	0.82	0.82	--	--	--	--	--	--	--
Fly Ash Haul Road Fugitives	1.89	0.87	0.05	--	--	--	--	--	--	--
Total Emissions	**184.01**	**178.17**	**176.43**	**80.41**	**494.52**	**841.71**	**33.66**	**2.09**	**2.09**	**6.28**

Additional details for determining the projected actual emissions for each respective pollutant are provided in Appendix B.

3.6 PROJECT EMISSIONS INCREASE SUMMARY

Table 3-4 summarizes the emissions increase totals for the proposed project. The emissions increase is calculated by taking the sum of the future projected actual emissions minus the baseline actual emissions. The emissions from all other emissions sources are not expected to change as a result of the project. As shown in Table 3-4, the project emissions increases of all pollutants are below their applicable PSD SERs. As such, the proposed cogeneration project is not subject to PSD review for any pollutant. Note that if an emission source shows an emission decrease, PTPC is not taking credit for the reduction in this calculation because a full netting analysis is not performed. As such, emission decreases are not provided in Table 3-4.

TABLE 3-4. EMISSIONS INCREASES FROM THE PROPOSED PROJECT

	TSP (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)	TRS (tpy)	H_2S (tpy)	H_2SO_4 (tpy)
Power Boiler 10	--	--	--	--	--	43.17	1.12	--	--	--
Recovery Furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower	1.32	1.32	1.32	--	--	--	--	--	--	--
Solid Fuel Handling Fugitives	0.05	0.03	0.004	--	--	--	--	--	--	--
Hog Fuel Haul Road Fugitives	4.75	1.32	0.13	--	--	--	--	--	--	--
Storage Pile Fugitives	0.85	0.43	0.43	--	--	--	--	--	--	--
Fly Ash Haul Road Fugitives	--	--	--	--	--	--	--	--	--	--
Total Emissions Increase	**6.97**	**3.09**	**1.88**	**0.00**	**0.00**	**43.17**	**1.12**	**0.00**	**0.00**	**0.00**
PSD Significant Emission Rate	25	15	10	40	40	100	40	10	10	7
Below PSD Significant Emission Rate?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

4. WASHINGTON TOXIC AIR POLLUTANT ANALYSIS

In the state of Washington, all new or modified sources emitting TAPs are required to demonstrate compliance with the Washington TAP standards pursuant to WAC 173-460. WAC 173-400-030(47) defines modification as follows:

> *any physical change in, or change in the method of operation of, a stationary source that increases the amount of any air contaminant emitted by such source or that results in the emissions of any air contaminant not previously emitted. The term modification shall be construed consistent with the definition of modification in Section 7411, Title 42, United States Code [NSPS], and with rules implementing that section.*

Power Boiler 10 will be physically modified and will have an increase in short term emission rates for specific TAPs. Therefore, the Power Boiler 10 meets the definition of modification, and compliance with the Washington TAP standards must be demonstrated. Emissions of NO_x, SO_2, PM, and trace metals are expected to decrease as a result of this project. NO_x emissions will decrease due to the installation of SNCR, SO_2 emissions will decrease due to the Power Boiler 10 firing less oil and adding caustic solution to the existing scrubber; and particulates are expected to decrease as a result of the proposed dry ESP. Using reductions in PM as a surrogate for trace metals, there will not be an increase in TAPs metals as a result of this project. As such, these TAPs are not included in the emission calculations.

A cooling tower, a new haul road route, two new solid fuel storage piles, and a solid fuel handling system will be added to the facility as a result of the cogeneration project. However, it is not expected that these two new emission sources will emit TAPs. Also, the Recovery Furnace will not be modified, as the short term TAP emissions will not increase as a result of the physical change to the emission unit. As such, the cooling tower, the new haul road route, the two new solid fuel storage piles, the solid fuel handling system, and the Recovery Furnace are not included in the TAP analysis.

Ecology has established a *de minimis* level, a Small Quantity Emission Rate (SQER), and an Acceptable Source Impact Level (ASIL) for each listed TAP.[32] An *acceptable source impact analysis* must be conducted for each TAP with an emission increase greater than the *de minimis* level.[33] If the net TAP emissions rate from all new or modified sources is above its respective SQER, further determination of compliance with the ASIL is required.

Table 4-1 shows potential emission increases of TAPs from the modified units that are above the corresponding SQERs and therefore require modeling. TAP emissions from the modified units are calculated using emission factors provided in the National Council for Air and Stream Improvement (NCASI) Technical Bulletin 973, Compilation of 'Air Toxic' and Total Hydrocarbon Emissions Data for Sources at Kraft, Sulfite and Non-Chemical Pulp Mills – a Second Update (2/2010). Detailed emission calculations for all TAPs are provided in Appendix C.

[32] De minimis levels, SQERs, and ASILs are provided for each TAP in WAC 173-460-150.

[33] The acceptable source impact analysis methodology is outlined in WAC 173-460-080. Its definition can be found in WAC 173-460-020(1).

TABLE 4-1. TOXIC AIR POLLUTANTS MODELED

Toxic Air Pollutant	Net Increase (lb/hr)	Net Increase (lb/day)	Net Increase (lb/yr)	SQER (lb/averaging period)	Averaging Period
1,2-Dichloroethane	--	--	2.5E+01	7.39E+00	year
1,2-Dibromoethane	--	--	4.7E+01	2.71E+00	year
1,2-Dichloropropane	--	--	2.8E+01	1.92E+01	year
2,3,7,8-Tetrachlorodibenzo-p-dioxin	--	--	5.9E-06	5.05E-06	year
2,3,7,8-Tetrachlorodibenzofuran	--	--	8.1E-05	5.05E-05	year
1,2,3,7,8-Pentachlorodibenzo-p-dioxin	--	--	1.1E-05	5.05E-06	year
2,3,4,7,8-Pentachlorodibenzofuran	--	--	2.7E-05	1.01E-05	year
Acetaldehyde	--	--	2.3E+02	7.10E+01	year
Acrolein	--	3.5E-01	--	7.89E-03	24-hr
Ammonia	--	1.7E+02	--	9.31E+00	24-hr
Benzene	--	--	2.0E+02	6.62E+00	year
Benzo(a)pyrene	--	--	2.2E+00	1.74E-01	year
Carbon Tetrachloride	--		1.1E+01	4.57E+00	year
Chlorine	--	1.8E+00	--	2.60E-02	24-hr
Chloroform	--	--	3.0E+01	8.35E+00	year
Dichloromethane	--	--	5.3E+02	1.92E+02	year
Formaldehyde	--	--	7.5E+02	3.20E+01	year
Hexachlorobenzene	--	--	8.8E-01	3.76E-01	year
Hydrogen Chloride	--	3.8E+00	--	1.18E+00	24-hr
Naphthalene	--	--	7.7E+01	5.64E+00	year
Perchloroethylene	--	--	3.2E+01	3.24E+01	year
Vinyl Chloride	--	--	1.6E+01	2.46E+00	year

4.1 SCREENING MODELING RESULTS

The TAP dispersion modeling is conducted with the SCREEN3 model. SCREEN3 is a screening dispersion model approved by EPA for evaluating ambient air impacts from a single source. Results from SCREEN3 modeling tend to produce conservative (i.e., high) estimates of impacts from emission sources.

SCREEN3 modeling analyses were conducted using the source parameters and the TAP emission increases from the Power Boiler 10. The TAP emission increase from the proposed project was modeled using the stack parameters of the Power Boiler 10. A unit emission rate (1 lb/hr) is used for the SCREEN3 modeling. SCREEN3 is a linear model; therefore, the maximum concentration results may be scaled in accordance with the actual emission rate of each modeled TAP to determine ambient concentrations of each pollutant.

As the SCREEN3 model reports results on a 1-hour averaging period, the resulting concentrations must be scaled to the averaging period of the respective ASILs. The commonly accepted scaling factor for the annual period is 0.08 and for the 24-hour period is 0.4.[34] For the purposes of this analysis, the 1-hour modeled concentrations are scaled by a factor of 0.08 and 0.4 to compare with the annual and 24-hour averaging period ASILs, respectively. The results of the toxics modeling are presented in Table 4-2.

Modeling files can be found in Appendix C of this report.

TABLE 4-2. MODELING RESULTS FOR TOXIC AIR POLLUTANTS

Toxic Air Pollutant	ASIL (μg/m^3)	ASIL Averaging Period	1-hr Modeling Results (μg/m^3)	Scaled Modeling Results (μg/m^3)	Does Scaled Modeling Pass?
1,2-Dichloroethane	3.85E-02	year	1.80E-02	1.44E-03	Yes
1,2-Dibromoethane	1.41E-02	year	3.38E-02	2.70E-03	Yes
1,2-Dichloropropane	1.00E-01	year	2.05E-02	1.64E-03	Yes
2,3,7,8-Tetrachlorodibenzo-p-dioxin	2.63E-08	year	4.25E-09	3.40E-10	Yes
2,3,7,8-Tetrachlorodibenzofuran	2.63E-07	year	5.84E-08	4.67E-09	Yes
1,2,3,7,8-Pentachlorodibenzo-p-dioxin	2.63E-08	year	7.95E-09	6.36E-10	Yes
2,3,4,7,8-Pentachlorodibenzofuran	5.26E-08	year	1.92E-08	1.54E-09	Yes
Acetaldehyde	3.70E-01	year	1.68E-01	1.35E-02	Yes
Acrolein	6.00E-02	24-hr	9.31E-02	3.72E-02	Yes
Ammonia	7.08E+01	24-hr	4.55E+01	1.82E+01	Yes
Benzene	3.45E-02	year	1.45E-01	1.16E-02	Yes
Benzo(a)pyrene	9.09E-04	year	1.60E-03	1.28E-04	Yes
Carbon Tetrachloride	2.38E-02	year	7.77E-03	6.21E-04	Yes
Chlorine	2.00E-01	24-hr	4.89E-01	1.96E-01	Yes
Chloroform	4.35E-02	year	2.17E-02	1.74E-03	Yes
Dichloromethane	1.00E+00	year	3.83E-01	3.07E-02	Yes
Formaldehyde	1.67E-01	year	5.44E-01	4.35E-02	Yes
Hexachlorobenzene	1.96E-03	year	6.35E-04	5.08E-05	Yes
Hydrogen Chloride	9.00E+00	24-hr	9.92E-01	3.97E-01	Yes
Naphthalene	2.94E-02	year	5.55E-02	4.44E-03	Yes
Perchloroethylene	1.69E-01	year	2.35E-02	1.88E-03	Yes
Vinyl Chloride	1.28E-02	year	1.13E-02	9.07E-04	Yes

Table 4-2 demonstrates that ambient concentrations of all TAPs are below their respective ASILs and are therefore in compliance with the Washington TAPs program. A tBACT analysis from the proposed project can be found in Section 5 of this report.

[34] Per Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and Standards, *Screening Procedures for Estimating the Air Quality Impact of Stationary Sources*, Revised. (Research Triangle Park, NC: U.S. EPA EPA-454/R-92-019), p. 15.

Under WAC 173-400-113(2), each new and/or modified source must employ BACT for all pollutants not previously emitted, or any pollutants for which emissions will increase as a result of the new source or modification. The Power Boiler 10 will experience short-term emissions increases of CO and VOC associated with the cogeneration project. Additionally, a new cooling tower, a new haul road route, a new solid fuel handling system, and two new solid fuel storage piles will be added to the Port Townsend Mill. The BACT analyses for these emission units are presented in the subsequent sections.

5.1 BACT METHODOLOGY

In a memorandum dated December 1, 1987, the EPA stated its preference for a "top-down" BACT analysis.[35] After determining if any New Source Performance Standard (NSPS) is applicable, the first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically, environmentally, or economically infeasible for the unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. The five basic steps of a top-down BACT review as identified by the EPA are presented below.[36]

STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

Available control technologies are identified for each emission unit in question. The following methods are used to identify potential technologies: (1) reviewing entries in the Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database, (2) surveying regulatory agencies, (3) drawing from similar experience in assessing emissions control strategies, (4) surveying air pollution control equipment vendors, and/or (5) researching available literature. [37]

STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

After the identification of control options, an analysis is conducted to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that prohibit the implementation of the control technology or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits, such as an NSPS.

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[35] U.S. EPA, Office of Air and Radiation. Memorandum from J.C. Potter to the Regional Administrators. Washington, D.C. December 1, 1987.

[36] U.S. EPA. *Draft New Source Review Workshop Manual*, Chapter B. Research Triangle Park, North Carolina. October, 1990.

[37] The RBLC search results in Appendix D are presented exactly as they are entered into the RBLC database.

STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

Once technically infeasible options are removed from consideration, the remaining options are ranked based on their control effectiveness. If there is only one remaining option or if all of the remaining technologies could achieve equivalent control efficiencies, ranking based on control efficiency is not required.

STEP 4 – EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

Beginning with the most efficient control option in the ranking, detailed economic, energy, and environmental impact evaluations are performed. If a control option is determined to be economically feasible without adverse energy or environmental impacts, it is not necessary to evaluate the remaining options with lower control efficiencies.

The economic evaluation centers on the cost effectiveness of the control option. Costs of installing and operating control technologies are estimated and annualized following the methodologies outlined in the EPA's *OAQPS Control Cost Manual* (CCM) and other industry resources.[38]

STEP 5 – SELECT BACT

In the final step, one pollutant-specific control option is proposed as BACT for each emission unit under review based on evaluations from the previous step.

The EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether the "top-down" approach is used. First, the BACT analysis must include consideration of the most stringent available control technologies, i.e., those which provide the "maximum degree of emissions reduction." Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts."

5.2 BACT ANALYSES FOR THE POWER BOILER 10

The Power Boiler 10 is a multi-fuel boiler that produces a large portion of the Port Townsend Mill's process steam demand. The heat required to produce the steam is provided primarily by the combustion of wood fuel. The emissions of PM, NO_x, and SO_2 will not increase as a result of this project due to the addition of a new ESP, SNCR, and adding caustic solution to the existing scrubber. The only emissions that will increase as a result of the Power Boiler 10 modifications are VOC and CO. Thus, the BACT analyses for CO and VOC from the Power Boiler 10 are presented in the following sections.

5.2.1 BACT ANALYSIS FOR CO AND VOC EMISSIONS FROM THE POWER BOILER 10

As the technologies used to control emissions of CO are typically identical to the technologies used to control emissions of VOC, the BACT determination for both CO and

[38] Office of Air Quality Planning and Standards (OAQPS), *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA 452-02-001 (http://www.epa.gov/ttn/catc/products.html#cccinfo), January 2002.

VOC emissions are simultaneously addressed in this section. Potentially applicable CO and VOC control technologies were identified based on a review of relevant information published in literature, information provided by prospective control technology vendors, determinations for similar units identified from the RBLC search, and experience in conducting control technology reviews for similar types of equipment. After accounting for the physical and operational characteristics of the Power Boiler 10, the control technologies and strategies considered in this BACT analysis for controlling CO and VOC emissions include the following:

- Thermal Oxidation
- Catalytic Oxidation
- Carbon Adsorption
- Polymer Adsorption
- Wet Scrubber
- Good Operating Practices

The top-down BACT analysis for CO and VOC emissions from the Power Boiler 10 is presented in Table 5-1 and a summary of relevant RBLC search results are presented in Appendix D. Good operating practices represent BACT for the Power Boiler 10 because this is the only feasible option for control of CO and VOC emissions. PTPC proposes CO and VOC BACT limits of 145 lbs CO per hr on an eight-hour average and 4.1 lbs VOC per hr, respectively.

A fuel cost analysis for installing thermal oxidation technology on the Power Boiler 10 is included in Appendix E. It is important to note that PTPC is installing an over-fire air system that is expected to reduce CO and VOC emissions by an estimated 60 percent. The economic infeasibility for the thermal oxidation system is based on the CO and VOC emissions after the over-fire air system is installed, and then applying the assumed control efficiency of the thermal oxidation technology. Even with this conservative approach, the cost effectiveness of adding the thermal oxidation system (fuel costs only included in cost analysis) results in a cost of $21,348 per ton CO and VOC removed. Thus, thermal oxidation is considered economically infeasible.

A detailed cost analysis demonstrating that installing catalytic oxidation technology on the Power Boiler 10 is included in Appendix E. As described above, the new over-fire air system is expected to reduce CO and VOC emissions by an estimated 60 percent. The economic infeasibility for the catalytic oxidation system is based on the CO and VOC emissions after the over-fire air system is installed, and then applying the assumed control efficiency of the catalytic oxidation technology. Even with this conservative approach, the cost effectiveness of adding the catalytic oxidation system results in a cost of $11,054 per ton CO and VOC removed. Thus, catalytic oxidation is considered economically infeasible.

TABLE 5-1. CO AND VOC TOP-DOWN BACT ANALYSIS FOR THE POWER BOILER 10

PROCESS		STEP 1. IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES		STEP 2. ELIMINATE TECHNICALLY INFEASIBLE OPTIONS		STEP 3. RANK REMAINING CONTROL TECHNOLOGIES	STEP 4. EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	STEP 5. SELECT BACT
Equipment	**Pollutant**	**Control Technology**	**Control Technology Description**	**RBLC Search Results**	**Technical Feasibility**	**Typical Overall Control Efficiency**	**Cost Effectiveness, $/ton**	
Power Boiler 10	CO and VOC	Thermal Oxidation	Regenerative thermal oxidizers, recuperative thermal oxidizers, and thermal incinerators all use efficient combustion technologies to destroy VOC emissions by burning the exhaust gas stream. In order to reach the temperature necessary to achieve efficient control of VOC, the exhaust stream must be heated to 1,400 ºF – 1,500 ºF by burning auxiliary fuel. Recuperative and Regenerative Thermal Oxidizers allow for a more efficient design with a heat exchanger to provide fuel cost savings.	Not listed for comparable emissions source.	Technically Feasible. However, implementing thermal oxidation requires the combustion of auxiliary fuel, which increases PM, NO_x, CO, and VOC emissions. A conventional thermal incinerator does not have heat recovery capability. Therefore, fuel cost is extremely high ($8,973,375 per year) and is not suitable for high volume flow applications.[39]	98%	Only accounting for fuel costs, controlling CO and VOC emissions by thermal oxidation would cost $21,348 per ton removed. Thus, implementing thermal oxidation would be economically infeasible.	
	CO and VOC	Catalytic Oxidation	Catalytic oxidation allows complete oxidation to take place at a faster rate and lower temperature than is possible with thermal oxidation. The gas stream is passed through a flame area and then through a catalyst bed, where CO and VOC emissions are controlled using catalytic oxidation. Prior to entering the catalyst bed, the exhaust gas must be preheated to 600 ºF – 800 ºF by burning auxiliary fuel.[30] Below this temperature range, the reaction rate drops sharply and effective oxidation of CO and VOC is no longer practicable. Above this temperature, conventional oxidation catalysts break down and are unable to perform their desired functions.	Listed for comparable emissions source.	Technically Feasible. However, implementing catalytic oxidation requires the combustion of auxiliary fuel, which increases PM, NO_x, CO, and VOC emissions. Also, catalytic oxidation is suited for systems with low exhaust volumes, little variation in VOC type/concentration, and where catalyst poisons (sulfur or particulate) are not present.[40] The Power Boiler 10 has a higher exhaust volume than the typical gas flow for a catalytic incinerator. Additionally there is potential for particulates and sulfur in the gas stream that could contaminate the catalyst. Thus, implementing catalytic oxidation poses some significant challenges.	95%	Controlling CO and VOC emissions by catalytic oxidation would cost $11,054 per ton removed. Thus, implementing catalytic oxidation would be economically infeasible.	

[39] The auxiliary fuel cost for controlling emissions from the Power Boiler 10 using a conventional thermal oxidizer is calculated assuming RFO is used to heat the Power Boiler 10 exhaust to the minimum temperature (1,100 ºF) required for operating a thermal oxidizer.
[40] EPA, Air Pollution Control Technology Fact Sheet, EPA-452/F-03-018, Catalytic Incinerator, dated July 15, 2003.

TABLE 5-1. CO AND VOC TOP-DOWN BACT ANALYSIS FOR THE POWER BOILER 10 (CONTINUED)

PROCESS		STEP 1. IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES		STEP 2. ELIMINATE TECHNICALLY INFEASIBLE OPTIONS		STEP 3. RANK REMAINING CONTROL TECHNOLOGIES	STEP 4. EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	STEP 5. SELECT BACT
Equipment	**Pollutant**	**Control Technology**	**Control Technology Description**	**RBLC Search Results**	**Technical Feasibility**	**Typical Overall Control Efficiency**	**Cost Effectiveness, $/ton**	
Power Boiler 10	CO and VOC	Carbon Adsorption	Carbon adsorption systems can potentially be used to remove VOC from exhaust gas streams. The core component of a carbon adsorption system is an activated carbon bed contained in a steel vessel. The VOC laden gas passes through the carbon bed where the VOC is adsorbed on the activated carbon. The spent carbon is regenerated either at an on-site regeneration facility or by an off-site activated carbon supplier.	Not listed for comparable emissions source.	Carbon adsorption is not recommended for low concentration, high volume exhausts, such as the exhaust on the Power Boiler 10. Carbon adsorption is not recommended for exhaust streams with high humidity and temperatures over 130 °F[41]. The exhaust from the Power Boiler 10 is expected to be 141 °F; therefore, carbon adsorption is considered technically infeasible.	N/A	N/A	
		Polymer Adsorption	Polymer adsorption systems can potentially be used to remove VOC and CO from exhaust gas steams. The core component of a polymer adsorption system is synthetic polymer designed to adsorb the target VOC and CO. The polymer can be contained in fixed beds, fluidized beds, or fluidized beds in series with counter-current flow to the VOC and CO laden gas. The VOC and CO laden gas passes through the polymer bed where the VOC and CO is adsorbed on the polymer. The cleaned gas is discharged to the atmosphere. The spent polymer is regenerated by applying heat to displace the adsorbed organic compounds at high temperatures. The VOC and CO are either recovered or burned in a separate device.	Not listed for comparable emissions source	Polymer adsorption is not recommended for low concentration, high volume exhausts, such as the exhaust on the Power Boiler 10. Polymer adsorption requires the surface of the polymer to remain clean. As a result of the fuel fired, the Power Boiler 10 exhaust contains PM and condensable organic compounds that would coat the polymer beads, blocking access of VOC and CO to the pores, thus rendering the polymers ineffective. Therefore, polymer adsorption is considered technically infeasible.	N/A	N/A	

[41] Noll, Kenneth E., Air and Waste Management Association, Air Pollution Engineering Manual, Second Edition, "Adsorption", 2000.

TABLE 5-1. CO AND VOC TOP-DOWN BACT ANALYSIS FOR THE POWER BOILER 10 (CONTINUED)

PROCESS		STEP 1. IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES		STEP 2. ELIMINATE TECHNICALLY INFEASIBLE OPTIONS		STEP 3. RANK REMAINING CONTROL TECHNOLOGIES	STEP 4. EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	STEP 5. SELECT BACT
Equipment	**Pollutant**	**Control Technology**	**Control Technology Description**	**RBLC Search Results**	**Technical Feasibility**	**Typical Overall Control Efficiency**	**Cost Effectiveness, $/ton**	
Power Boiler 10	CO and VOC	Wet Scrubber	Wet scrubbing of gas or vapor pollutants from a gas stream is usually accomplished in a packed column (or other type of column) where pollutants are absorbed by countercurrent flow of a scrubbing liquid. Wet scrubbing is only effective for water soluble emissions.	Not listed for comparable emissions source	Wet scrubbers remove water soluble VOC emissions. As a significant portion of VOC and CO emissions from the Power Boiler 10 are not water soluble, wet scrubbing technology is considered technically infeasible for the removal of VOC emissions from the boiler.[42]	N/A	N/A	
		Good Operating Practices	A properly operated boiler will minimize the formation of CO and VOC emissions. Proper design of the boiler includes features such as the fuel and combustion air delivery system and the shape and size of the combustion chamber. Additionally, a new overfire air system will be added to the Power Boiler 10, which will reduce CO and VOC emissions because of the increased combustion efficiency.	Listed for comparable emissions source	Technically feasible.			

[42] Per correspondence with the Harris Group.

5.2.2 BACT ANALYSIS FOR TOXIC AIR POLLUTANT EMISSIONS FROM THE POWER BOILER 10

TAP emissions increases from the Power Boiler 10 are primarily constituents of VOC. The BACT analysis conducted for VOC is presented in Section 5.2.1 may be extended to individual TAPs that are constituents of VOC. As such, the proposed BACT determination for VOC emissions discussed in the previous section is also valid for TAP emissions that are constituents of VOC. The TAPs that are constituents of PM are expected to decrease as a result of this project due to the addition of the dry ESP. Thus, tBACT is not required for TAP constituents of PM.

Per WAC 173-460-150, NO_2, CO, and SO_2 are also listed as TAPs. Emission of NO_2 and SO_2 are expected to decrease as a result of this project. NO_2 emissions will decrease due to the installation of SNCR; SO_2 emissions will decrease due the Power Boiler 10 firing less oil and adding caustic solution to the existing scrubber. The BACT analysis conducted for CO is presented in Section 5.2.1 and represents tBACT as well.

Such TAPs as ammonia, hydrogen chloride, chlorine, carbon tetrachloride, and carbon disulfide are not constituents of PM or VOC. Ammonia emissions will be generated due to the addition of the SNCR system on the Power Boiler 10. Ammonia is highly soluble in water and it is assumed that the existing wet scrubber will be effective in controlling ammonia emissions.[43] PTPC proposes an ammonia tBACT limit of 25 ppmv for the Power Boiler 10. Carbon disulfide is considered a sulfide. Thus, adding caustic solution to the existing wet scrubber for SO_2 can be extended to represent tBACT for carbon disulfide. HCl and chlorine are controlled through the wet scrubber. Therefore, the wet scrubber that is currently installed is proposed as tBACT for the HCl and chlorine.

5.3 BACT ANALYSIS FOR PM_{10} FROM THE COOLING TOWER

PTPC proposes the use of a mist eliminator as BACT for PM_{10} emissions from the cooling tower. The EPA's RACT/BACT/LAER Clearinghouse (RBLC) lists mist eliminators as the only BACT determination for PM_{10} emissions from cooling towers. Mist eliminators rely on inertial separation caused by directional changes as air passes through the eliminators to minimize drift. As mist eliminators are the most effective control technology to reduce PM_{10} emissions from cooling towers, alternate control technologies are not addressed. The drift rate of the proposed mist eliminator will be 0.001%, which is in line with the recent determinations in the RBLC database. A summary of relevant RBLC search results are presented in Appendix D.

The cooling tower will not use water treatment chemicals that contain any hazardous air pollutants or TAPs listed in WAC 173-460.

[43] Control and Pollution Prevention Options for Ammonia Emissions, EPA-456/R-95-002, April 1995.

5.4 BACT ANALYSIS FOR PM_{10} FROM FUGITIVE EMISSIONS

The cogeneration project will add a new solid fuel handling system, a new haul road route and two new solid fuel storage piles to the Port Townsend Mill. These four sources will increase PM fugitive emissions. Since total PM emissions from these sources are inherently low (1.69 tpy total PM_{10} increase for all four sources, which is close to the NSR exemption threshold established by WAC 173-400-110(5)(d) for PM_{10} emissions), PTPC concludes that all control technologies are deemed either technically or economically infeasible for reducing PM fugitive emissions from the new solid fuel handling system, the new haul road route, and the two new solid fuel storage piles. Therefore, the selected BACT for PM emissions from the new fugitive operations is good operating practices.

APPENDIX A

APPLICATION FORMS INCLUDING:

NOC Application Form
PSD Applicability Form
SEPA Checklist

PTPC SITE MAP AND EQUIPMENT LAYOUT

COGENERATION PROJECT PROCESS FLOW DIAGRAMS

STATE OF WASHINGTON DEPARTMENT OF ECOLOGY
NOTICE OF CONSTRUCTION APPLICATION
DECLARING INTENT TO CONSTRUCT, INSTALL OR ESTABLISH
OR
REPLACEMENT OR SUBSTANTIAL ALTERATION OF
EMISSION CONTROL TECHOLOGY ON AN EXISTING STATIONARY SOURCE

I. PERMITTING AUTHORITY (Send Completed Application to this address)

Department of Ecology Headquarters / Industrial Section PO Box 47600 Olympia WA 98504-7600 360-407-6000	Department of Ecology Central Region 15 East Yakima Avenue, Suite 200 Yakima WA 98902-3452 509-575-2490	Department of Ecology Eastern Region North 4601 Monroe Spokane WA 98205-1295 (509) 329-3400

II. COMPANY INFORMATION

1. Legal Name of Company Port Townsend Paper Corporation for Port Townsend Cogeneration Project, LLC	
2. Company Mailing Address (street, city, state, zip) 100 Mill Road, Port Townsend, WA, 98368	
3. Company Responsible Official & Title Roger A. Loney, Senior Vice President- General Manager	
4. Company Phone Number (360) 385-3170	5. Company FAX Number (360) 385-0355

III. FACILITY INFORMATION

1. Facility Name (if different from Legal Company Name above) Port Townsend Mill	
2. Facility Mailing Address (if different from Company Mailing Address above) 100 Mill Road, Port Townsend, WA, 98368	
3. Facility Site Legal Description Southeast Quarter, Section 16, Township 30N, Range 1W	
4. Facility Contact Person (if different from Company Responsible Official above) Eveleen Muehlethaler, Vice President, Environmental Affairs	
5. Facility Phone Number (if different from Company Phone # above) 360-379-2112	6. Facility FAX # (if different from Company FAX # above) 360-379-2213
7. General Proposal for Facility (see section on next page for specific description of proposal). Cogeneration Project	
8. Proposal Construction Starting Date December, 2010	9. Proposal Construction Completion Date 2011

IV. PROPOSAL INFORMATION

1. Complete Description of Specific Proposal (attach Drawings, Schematics, Prints or Block Diagrams)

Please see the Introduction Section (Section 1) of the Port Townsend Paper Corporation Notice of Construction Application, May 2010.

2. This Application is for (Please Check One):

- ☐ New Construction
- ☐ Existing Equipment / Facility Operating without a Permit
- ☐ Change of Control Technology
- ☒ Modification to Facility
- ☐ New Permit Conditions
- ☐ Production Increase

3. Complete Description of Best Available control Technology (BACT) for Proposal (see attached Summary of BACT Process)
Attach Manufacturer's or Vendor's Information.

Please see the BACT Analysis Section (Section 5) of the Port Townsend Paper Corporation Notice of Construction Application, May 2010.

4. Maximum Potential Production Output per Year 3,626,640 MMBtu/yr for the Power Boiler 10	5. Maximum Potential Production Output per Hour 414 MMBtu/hr for the Power Boiler 10
6. Actual Production Output per Year N/A	7. Actual Production Output per Hour N/A

8. Operating Schedule	Hours Per Day 24	Days Per Week 7		Weeks per Year 52
9. Percentage of Production	Jan-Feb-Mar 25	April-May-June 25	July-Aug-Sept 25	Oct-Nov-Dec 25

V. EMISSIONS ESTIMATIONS OF CRITERIA POLLUTANTS

1. Particulate Matter (PM) (Pounds or Tons per Year) **Refer to Appendix B of attached report for detailed emission calculations**. Actual Emissions =	Potential Emissions =
2. Nitrogen Oxides (NO_x) (Pounds or Tons per Year) Actual Emissions =	Potential Emissions =
3. Carbon Monoxide (CO) (Pounds or tons per Year) Actual Emissions =	Potential Emissions =
4. Sulfur Dioxide (SO2) (Pounds or Tons per Year) Actual Emissions =	Potential Emissions =
5. Volatile Organic Compounds (VOCs) (Pounds or Tons per Year) Actual Emissions =	Potential Emissions =
6. Lead (Pb) (Pounds or Tons per Year) Actual Emissions =	Potential Emissions =

VI. EMISSIONS ESTIMATIONS OF TOXIC AIR POLLUTANTS (consult Chapter 173-460 WAC)

Pollutant #1 (List Pollutant Name, Pounds per Hour/Pounds per Year) **Refer to Section 4 and Appendix C of attached report for detailed calculations**. Pollutant	Actual Emissions =	Potential Emissions =
Pollutant #2 (List Pollutant Name, Pounds per Hour/Pounds per Year) Pollutant	Actual Emissions =	Potential Emissions =
Pollutant #3 (List Pollutant Name, Pounds per Hour/Pounds per Year) Pollutant	Actual Emissions =	Potential Emissions =
Pollutant #4 (List Pollutant Name, Pounds per Hour/Pounds per Year) Pollutant	Actual Emissions =	Potential Emissions =
Pollutant #5 (List Pollutant Name, Pounds per Hour/Pounds per Year) Pollutant	Actual Emissions =	Potential Emissions =
Pollutant #6 (List Pollutant Name, Pounds per Hour/Pounds per Year) Pollutant	Actual Emissions =	Potential Emissions =
Pollutant #7 (List Pollutant Name, Pounds per Hour/Pounds per Year) Pollutant	Actual Emissions =	Potential Emissions =

VII. EMISSIONS ESTIMATIONS OF FUGITIVE AIR POLLUTANTS

Pollutant #1 (List Pollutant Name, Pounds per Hour/Pounds per Year) **Refer to Appendix B of attached report for detailed emission calculations**. Pollutant	Pounds per Hour =	Pounds per Year =
Pollutant #1 (List Pollutant Name, Pounds per Hour/Pounds per Year) Pollutant	Pounds per Hour =	Pounds per Year =

VIII. MODELING RESULTS

1. List Modeling Results of Criteria Air Pollutants (attach any Modeling Printouts) N/A
2. List Modeling Results of Toxic Air Pollutants (attach any Modeling Printouts) See Section 4.1 (Screening Modeling Results) of the attached report.

IX. EMISSIONS DATA AT DISCHARGE POINT

No new stacks associated with the project.

Stack Parameters	Other than Stack Parameters
1. List the Number of Stacks under this Proposal Power Boiler 10, Existing Stack	1. List the Number of Discharge Points under this Proposal
2. List the Gas Velocity for each Stack 15.1263 m/s	2. List the Gas Velocity for each Discharge Point
3. List the Height for each Stack 174 ft	3. List the Height for each Discharge Point
4. List the Inside Diameter or Dimensions for each Stack 7.0 ft.	4. List the Inside Diameter or dimensions for each Discharge Point
5. List the Gas Exit Temperature for each Stack 142 F	5. List the Gas Exit Temperature for each Discharge Point
6. List the Building Height, Width, Length for each Stack	6. List the Building Height, Width, Length for each Discharge Point
7. List the Height of the Tallest Building On-site or in the Vicinity 48.77 m	7. List the Height of the Tallest Building On-site or in the Vicinity
8. List Whether the Facility is in an Urban or Rural Location Rural	8. List Whether the Facility is in an Urban or Rural Location
9. List the Distance from each Stack to the Property Line 182.9 m	9. List the Distance from each Discharge Point to the Property Line
10. Is this Stack Shared by more than One Source? No	10. Is this a Shared Discharge Point?
11. List the Volumetric Flow Rate for each Stack 100,836 dscfm	11. List the Volumetric Flow Rate for each Discharge Point
12. How does each Stack Discharge, Vertically or Horizontally? Vertically	12. How does each Discharge Point Vent, Vertically or Horizontally?

X. FUEL DATA

	PRIMARY FUEL	SECONDARY FUEL
1. Type (Natural Gas, Oil, Coal, Hogged Fuel, etc.	No new fuels associated with project.	
2. Unit of Measure (Gallons, Cubic Feet, Tons, etc)		
3. Maximum Consumption Units per Hour		
4. Maximum Consumption Units per Year		
5. Actual Consumption Units per Hour		
6. Actual Consumption Units per Year		
7. BTU per Unit of Measure		
8. Percent Sulfur (if applicable)		
9. Percent Ash (if applicable)		

XI. AIR POLLUTION CONTROL EQUIPMENT (ATTACH VENDOR'S INFORMATION)

BAGHOUSE	SCRUBBER	CYCLONE	E.S.P. – Design Parameters Unknown	ADSORPTION
1. Type	1. Type	1. Type	1. Type	1. Type
2. Efficiency	2. Efficiency	2. Efficiency	2. Efficiency	2. Efficiency
3. Bag height	3. Dimensions	3. Dimensions	3. Dimensions–Plate spacing, height, length (attach layout)	3. Gas Flow Rate (cfm)
4. Bag diameter	4. Gas Differential Pressure	4. Gas Differential Pressure	4. Fields	4. Bed Media
5. Number of bags	5. Type of scrubber liquid	5. Gas Flow Rate (cfm)	5. Configuration	5. Adsorption Isotherm (attach graph)
6. Filter Area (sq. feet)	6. Liquid Flow Rate gpm)	6. Other	6. Gas Velocity (fpm)	6. Surface Area (sq. feet)
7. Filter Media	7. Gas Flow Rate (cfm)		7. Gas Flow Rate (cfm)	7. Gas Velocity (fpm)
8. Gas Flow Rate (cfm)	8. Scrubber Packing Material		8. Residence Time	8. Gas Temperature (deg. F)
9. Air- to-Cloth Ratio			9. Gas Differential Pressure	9. Bed Volume (cubic feet)
10. Overall Dimensions			10. Precipitation Rate	10. Bed Dimensions
11. Cleaning Mechanism			11. Prim/Sec. Voltage	11. Capacity (hours)
12. Other			12. Prim/Sec. Current	12. Contaminant
13. Other			13. Corona Strength	13. Regeneration Time
14. Other			14. Gas Temperature (deg. F)	14. Regeneration Type

XII. OTHER DATA

1. Site Plan and Equipment Layout for the site attached?	☒YES ☐NO
2. MSDS Sheets for Chemicals or Materials related to this proposal attached?	☐YES ☒NO
3. Vendor's and/or Manufacturer's information attached?	☐YES ☒NO
4. Modeling Information attached?	☒YES ☐NO
5. Fugitive Dust Control Plan attached?	☐YES ☒NO
6. All Enclosures for your Specific Proposal attached?	☒YES ☐NO
7. Name and Title of Person Filling out this Form Printed Name Melissa Hillman Signature [signature] Date 6/14/2010	
8. Name and Title of Responsible Official Printed Name Roger A. Loney, Sr. VP-General Manager Signature [signature] Date 6/15/2010	

No new equipment associated with project

XIII. ADDITIONAL INFORMATION FOR SPECIFIC EQUIPMENT (Attach Vendor's Information)

BOILER	BURNER	ASPHALT PLANT	SAND / GRAVEL	PAINT BOOTH
1. Type and Number Power Boiler 10 2. Size (BTU per hour input 414 MMBtu/hr 3. Size (steam pounds per hour) 250,000 lb/hr 4. Efficiency 68% 5. NOx Rating (PPM@ 7% Oxygen) ____ 6. CO Rating (PPM @ 7% Oxygen) ____	1. Type and Number ____ 2. Size (BTU per hour input ____ 3. NOx Rating (PPPM@7% Oxygen) ____ 4. CO Rating (PPM @ 7% Oxygen) ____	1. Type (Drum, Batch) ____ 2. Size (tons per hour) ____ 3. VOC Emission Points (attach layout) ____ 4. VOC Controls ____ 5. Aggregate Piles (acres) ____ 6. Off Road Vehicle Use (miles per year) ____ 7. Power (Line, Genset, etc.) ____ 8. Number of Vehicles ____	1.Crusher Type (Prim., Sec., Tertiary) (attach layout) ____ 2. Size (tons per hour) ____ 3. Number of Screens ____ 4. Number of Conveyors ____ 5. Fog Spray Location (attach layout) ____ 6. Aggregate Piles (acres) ____ 7. Off Road Vehicle Use (miles per year) ____ 8. Number of Vehicles ____	1.Operation Type ____ 2. Application Method ____ 3. Filter Bank Area ____ 4. Filter Exhaust Flow ____ 5. Coating & Solvent Types & MSDS Sheets (attach details) ____ 6. Gun Cleaning Method ____ 7. Drying Method ____

LANDFILL	ABRASIVE BLASTING	CONCRETE BATCH	OTHER	OTHER
1. Type ____ 2. Capacity (tons) ____ 3. Year started ____ 4. Year closed ____ 5. Area of Landfill (attach site plan) ____	1. Attach details of booth or hanger to be used ____ 2. Abrasive Materials to be used. Attach MSDS Sheet(s) ____ 3. Filter Bank Area ____ 4. Filter Exhaust Flow ____ 5. Approximate Number of Items to be Abrasively Blasted each Calendar Year. ____	1. Size (tons or cubic yards of product)) ____ 2. Cement Silo Controls (baghouse, etc.) ____ 3. Charging Station Controls (baghouse, enclosure, etc.) ____ 4. Conveyor Controls ____		

To receive this document in an alternate format, contact the program number listed above or 711 or 1-800-6388 (TTY)

PSD APPLICABILITY FORM

This form is an aid to help determine if a proposed project will be required to undergo a PSD applicability review by the State of Washington Air Quality Program. This form should accompany the Notice of Construction application that is submitted to the Local Air Authority. For locations in eastern Washington where the Department of Ecology is the delegated local air authority, submit this form to the appropriate Ecology Regional Office.

It is the responsibility of the applicant to ensure that all preconstruction permits are obtained before commencement of construction.

COMPANY INFORMATION

Company or owner name: PTPC for Port Townsend Cogeneration Project, LLC

Mailing address: 100 Mill Road, Port Townsend, WA, 98368

Facility address: 100 Mill Road, Port Townsend, WA, 98368

Contact: Eveleen Muehlethaler, Vice President, Environmental Affairs

Telephone: (360) 379-2112

Fax: (360) 379-2213

e-mail: eveleenm@ptpc.com

Facility industrial classification and SIC: 2611

If you require this document in an alternate format, please call Tami Dahlgren at (360) 407-6830 (voice), or 711 or 1-800-833-6388 (TTY only).

PROCESS INFORMATION AND EMISSIONS CALCULATIONS

This section is intended to furnish a best estimate of annual emissions and sufficient information for agency technical staff to verify the applicant's conclusions in answering the questions in the next section. Please provide:

(1) A description of the process with a flow diagram indicating points of emissions to the air.

(2) Design and operating parameters for the process (i.e., hours of operation per year, maximum and normal production rates, fuel and raw material requirements).

(3) Estimates of the potential emissions for all air pollutants from each emissions point and a description of the method or basis used to make the emission estimates (in enough detail so that one can follow the logic and the calculation steps). Potential emissions are based on the maximum possible rate from each emission point taking into account air pollution control equipment.

For either a new or modified source, calculate the **Potential to Emit** of each regulated pollutant based on operation at maximum capacity (such as 8,760 hours/year) with emissions control equipment operating.

For a modified source, subtract the **Actual** emissions of the existing source from the **Potential to Emit** of the modified source to calculate the emissions increase (decrease). Actual emissions are the average of the last 24 months of operation, if that period is representative of normal operations.

Regulated Pollutant Under PSD	Potential To Emit Tons/Year [1]	Actual Emissions Tons/Year	Emissions Increase (Decrease)	Significant PSD Rate Tons/Year
Carbon monoxide (CO)	841.71	798.54	43.17	100
Nitrogen oxides (NOx)	258.78	258.78	0	40
Sulfur dioxide (SO_2)	7.88	7.88	0	40
Particulate matter (PM)	154.92	147.95	6.97	25
Particulate matter (PM_{10})	150.43	147.34	3.09	15
Volatile organic compounds (VOCs)	33.66	32.54	1.12	40
Ozone depleting substances				100
Lead				0.6
Fluorides				3
Sulfuric acid mist				7
Hydrogen sulfide (H_2S)	1.63	1.63	0	10
Total reduced sulfur (including H_2S)	1.63	1.63	0	10
Reduced sulfur compounds (including H_2S)	1.63	1.63	0	10
Municipal waste combustor organics measured as dioxins and furans				$3.5x10^{-6}$ (= 3.2 grams/yr)
Municipal waste combustor metals				15
Municipal waste combustor acid gasses				40
Municipal waste landfill nonmethane organic compounds				50

1 Value in this column represent Projected Actual Emissions.

QUESTION 1 (Is the major source threshold 100 or 250 tons per year?)

Does the existing, modified, or new source fall within one of the following 28 source categories?

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

☑ YES Please indicate one source category number 3, then GO TO QUESTION 2.

☐ NO GO TO QUESTION 3.

QUESTION 2 (Are you a 100 ton major source?)

Does the potential to emit of any one regulated pollutant (including fugitive emissions) from the existing, modified, or new source exceed 100 tons per year?

☑ YES GO TO QUESTION 6.

☐ NO PSD IS NOT REQUIRED. DO NOT ANSWER ANY MORE QUESTIONS.
SUBMIT THIS FORM WITH THE NOTICE OF CONSTRUCTION APPLICATION.

QUESTION 3 (Are you a 250 ton major source that is required to include fugitive emissions?)

Does the existing, modified, or new source fall within one of the following source categories?

1. Municipal Incinerators ($\geq$ 50 tons/day)
2. Asphalt concrete plants
3. Storage vessels for petroleum liquids, $\geq$ 40,000 gallons, construction after 06/11/73 and prior to 05/19/78.
4. Storage vessels for petroleum liquids, $\geq$ 40,000 gallons, construction after 05/18/78
5. Sewage treatment plants with sludge incinerators
6. Phosphate fertilizer industry: Plants manufacturing wet-process phosphoric acid, superphosphoric acid, diammonium phosphate, triple superphosphate, and granular triple superphosphate storage facilities.
7. Glass melting furnace $\geq$ 4,555 kilograms glass/day, (except all electric melters)
8. Grain elevators
9. Stationary gas turbines $\geq$ 10.7 gigajoules/hour heat input
10. Lead acid battery manufacturing plants
11. Automobile and light-duty truck assembly plant surface coating operations

☐ YES Please indicate one source category number ________, then GO TO QUESTION 4.

☐ NO GO TO QUESTION 5.

QUESTION 4 (Are you a 250 ton major source including fugitive emissions?)

Does the potential to emit of any one regulated pollutant (including fugitive emissions) from the existing, modified, or new source exceed 250 tons/year?

☐ YES GO TO QUESTION 6.

☐ NO PSD IS NOT REQUIRED. DO NOT ANSWER ANY MORE QUESTIONS. SUBMIT THIS FORM WITH THE NOTICE OF CONSTRUCTION APPLICATION.

QUESTION 5 (Are you a 250 ton major source not including fugitive emissions?)

Does the potential to emit of any one regulated pollutant (not including fugitive emissions) from the existing, modified, or new source exceed 250 tons per year?

☐ YES GO TO QUESTION 6.

☐ NO PSD IS NOT REQUIRED. DO NOT ANSWER ANY MORE QUESTIONS. SUBMIT THIS FORM WITH THE NOTICE OF CONSTRUCTION APPLICATION.

QUESTION 6 (Are you close to a Class I Area?)

Is the project a major stationary source or a modification to a major stationary source located within 10 kilometers (6.2 miles) of the boundary of a Class I area? Class I areas in Washington State are Mount Rainier National Park, North Cascade National Park, Olympic National Park, Alpine Lakes Wilderness Area, Glacier Peak Wilderness Area, Goat Rocks Wilderness Area, Mount Adams Wilderness Area, Pasayten Wilderness Area, and the Spokane Indian Reservation.

☐ YES PSD REVIEW IS REQUIRED IF THE MODELED IMPACT OF ANY REGULATED POLLUTANT ON THE CLASS I AREA IS EQUAL TO OR GREATER THAN 1 $\mu g/m^3$, (24-hour average).

☑ NO CONTINUE

QUESTION 7 (Are you a new source or modified source?)

Is the proposed project a

☐ New source? GO TO QUESTION 8.

☑ Modification, expansion, or addition to an existing source? GO TO QUESTION 9.

QUESTION 8 (For new sources: What are the PSD applicable pollutants?)

For which regulated pollutants does the potential to emit of the new source exceed their PSD significant rate?

PSD REVIEW IS PROBABLY REQUIRED FOR THESE POLLUTANTS.
YOU MUST MEET WITH THE DEPARTMENT OF ECOLOGY TO DISCUSS PSD APPLICABILITY.

QUESTION 9 (For modified sources: What are the PSD applicable pollutants?)

For which regulated pollutants does the emissions increase from the modified source exceed their PSD significant rate?

None.

PSD REVIEW IS PROBABLY REQUIRED FOR THESE POLLUTANTS.
YOU MUST MEET WITH THE DEPARTMENT OF ECOLOGY TO DISCUSS PSD APPLICABILITY.

WAC 197-11-960 Environmental checklist.

ENVIRONMENTAL CHECKLIST

Purpose of checklist:

The State Environmental Policy Act (SEPA), chapter 43.21C RCW, requires all governmental agencies to consider the environmental impacts of a proposal before making decisions. An environmental impact statement (EIS) must be prepared for all proposals with probable significant adverse impacts on the quality of the environment. The purpose of this checklist is to provide information to help you and the agency identify impacts from your proposal (and to reduce or avoid impacts from the proposal, if it can be done) and to help the agency decide whether an EIS is required.

Instructions for applicants:

This environmental checklist asks you to describe some basic information about your proposal. Governmental agencies use this checklist to determine whether the environmental impacts of your proposal are significant, requiring preparation of an EIS. Answer the questions briefly, with the most precise information known, or give the best description you can.

You must answer each question accurately and carefully, to the best of your knowledge. In most cases, you should be able to answer the questions from your own observations or project plans without the need to hire experts. If you really do not know the answer, or if a question does not apply to your proposal, write "do not know" or "does not apply." Complete answers to the questions now may avoid unnecessary delays later.

Some questions ask about governmental regulations, such as zoning, shoreline, and landmark designations. Answer these questions if you can. If you have problems, the governmental agencies can assist you.

The checklist questions apply to all parts of your proposal, even if you plan to do them over a period of time or on different parcels of land. Attach any additional information that will help describe your proposal or its environmental effects. The agency to which you submit this checklist may ask you to explain your answers or provide additional information reasonably related to determining if there may be significant adverse impact.

Use of checklist for nonproject proposals:

Complete this checklist for nonproject proposals, even though questions may be answered "does not apply." IN ADDITION, complete the SUPPLEMENTAL SHEET FOR NONPROJECT ACTIONS (part D).

For nonproject actions, the references in the checklist to the words "project," "applicant," and "property or site" should be read as "proposal," "proposer," and "affected geographic area," respectively.

A. BACKGROUND

1. Name of proposed project, if applicable: **Cogeneration Project**

2. Name of applicant: **Port Townsend Paper Corporation for Port Townsend Cogeneration Project, LLC**

3. Address and phone number of applicant and contact person:
100 Mill Road
Port Townsend, WA 98368

Contact: Eveleen Muehlethaler, Vice President, Environmental Affairs, Phone: 360-379-2112

4. Date checklist prepared: **5/21/2010**

5. Agency requesting checklist: **Washington State Department of Ecology**

6. Proposed timing or schedule (including phasing, if applicable):
Begin: December 2010
End: 2011

7. Do you have any plans for future additions, expansion, or further activity related to or connected with this proposal? If yes, explain.

No further additions or expansions are planned.

8. List any environmental information you know about that has been prepared, or will be prepared, directly related to this proposal.

Notice of Construction Permit Application

9. Do you know whether applications are pending for governmental approvals of other proposals directly affecting the property covered by your proposal? If yes, explain.
No.

10. List any government approvals or permits that will be needed for your proposal, if known.

Notice of Construction Application.

11. Give brief, complete description of your proposal, including the proposed uses and the size of the project and site. There are several questions later in this checklist that ask you to describe certain aspects of your proposal. You do not need to repeat those answers on this page. (Lead agencies may modify this form to include additional specific information on project description.)
PTPC has formed a partnership with Sterling Energy Assets (SEA) in order to produce green electricity that will be sold to the power distribution system. PTPC and SEA are proposing a project (cogeneration project) to install a new steam turbine generator that will extract steam from the Power Boiler 10 and the Recovery Furnace, and then supply the necessary steam to the PTPC mill in order to support mill operations as well. The steam turbine will generate less than 25 MW of electricity that will be sold to a power distribution system. In order to extract steam from the Power Boiler 10 and the Recovery Furnace, specific changes will be made to each emission unit. The Power Boiler 10 will primarily use wood fuel to generate any additional steam supplied to the new steam turbine. The existing Recovery Furnace at the mill will be physically changed as a result of the cogeneration project, but emissions from the Recovery Furnace are not expected to increase.
Additionally, the cogeneration project will involve modifications to the existing solid fuel handling system to the Power Boiler 10 and associated hog fuel storage piles. Truck haul road routes will be affected by the project as well. A new cooling tower will be added to support the steam turbine operations.

12. Location of the proposal. Give sufficient information for a person to understand the precise location of your proposed project, including a street address, if any, and section, township, and range, if known. If a proposal would occur over a range of area, provide the range or boundaries of the site(s). Provide a legal description, site plan, vicinity map, and topographic map, if reasonably available. While you should submit any plans required by the agency, you are not required to duplicate maps or detailed plans submitted with any permit applications related to this checklist.

The project area is located in Jefferson County in the Southeast Quarter, Section 16, Township 30N, Range 1W.

B. ENVIRONMENTAL ELEMENTS

1. **Earth**

a. General description of the site (circle one): Flat, rolling, hilly, steep slopes, mountainous, other . . . . . .
The project area is flat.

b. What is the steepest slope on the site (approximate percent slope)?
The project area is flat (<1% grade).

c. What general types of soils are found on the site (for example, clay, sand, gravel, peat, muck)? If you know the classification of agricultural soils, specify them and note any prime farmland.

Fill soils.

d. Are there surface indications or history of unstable soils in the immediate vicinity? If so, describe.

No.

e. Describe the purpose, type, and approximate quantities of any filling or grading proposed. Indicate source of fill.

A 250 'by 300' area will be cleared and graded to support the new turbine generator building, the biomass fuel system, and to accommodate changes to the plant road system.

f. Could erosion occur as a result of clearing, construction, or use? If so, generally describe.

Erosion is always a possibility so best management practices will be used to control erosion during and after construction.

g. About what percent of the site will be covered with impervious surfaces after project construction (for example, asphalt or buildings)?

There will be a less than 1/2 % increase in paving of the present industrial mill site .

h. Proposed measures to reduce or control erosion, or other impacts to the earth, if any:

Construction will conform to Jefferson County Building codes and as such conform to measures designed to reduce or prevent erosion, etc.

Air

a. What types of emissions to the air would result from the proposal (i.e., dust, automobile, odors, industrial wood smoke) during construction and when the project is completed? If any, generally describe and give approximate quantities if known.

This project will result in an emissions decrease for all PSD pollutants, except for Volatile Organic Carbons (VOCs) and Carbon Monoxide (CO). While VOCs and CO emissions will increase as a result of the cogeneration project, the respective increase will remain below the Significant Emission Rate (SER), and PSD review will not be triggered for any pollutant. Refer to the attached NOC application for more detailed emission calculations regulated to the cogeneration project.

b. Are there any off-site sources of emissions or odor that may affect your proposal? If so, generally describe.

No.

c. Proposed measures to reduce or control emissions or other impacts to air, if any:

Physically modified emission units will meet the Best Available Control Technology (BACT) requirements established by the Department of Ecology.

3. **Water**

a. Surface:

1) Is there any surface water body on or in the immediate vicinity of the site (including year-round and seasonal streams, saltwater, lakes, ponds, wetlands)? If yes, describe type and provide names. If appropriate, state what stream or river it flows into.

The mill is located on the waterfront of Glen Cove of Port Townsend Bay.

2) Will the project require any work over, in, or adjacent to (within 200 feet) the described waters? If yes, please describe and attach available plans.

The project is greater than 200 feet from shoreline.

3) Estimate the amount of fill and dredge material that would be placed in or removed from surface water or wetlands and indicate the area of the site that would be affected. Indicate the source of fill material.

None.

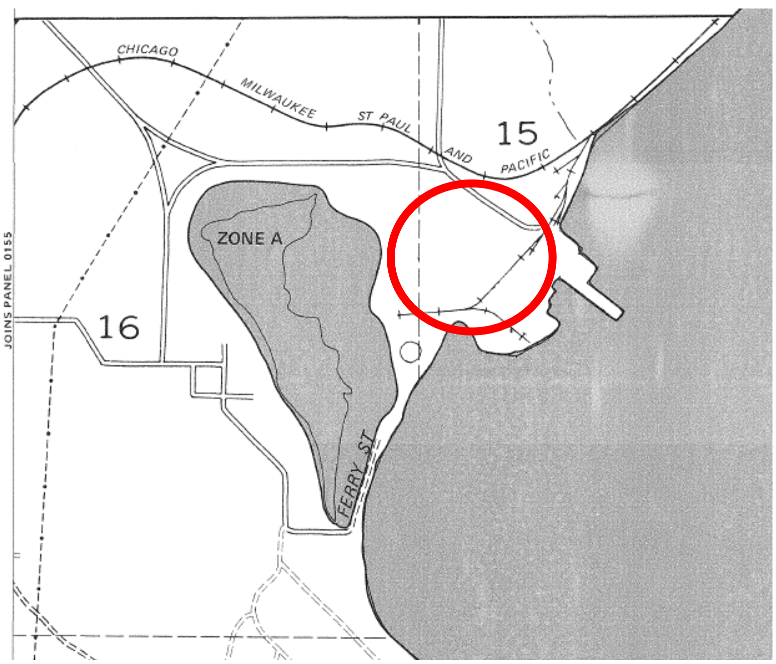
4) Will the proposal require surface water withdrawals or diversions? Give general description, purpose, and approximate quantities if known.

Cooling water for the steam turbine will be taken from the salt water cooling water system already in place.

No new withdrawals are planned.

5) Does the proposal lie within a 100-year floodplain? If so, note location on the site plan.

No, the project area is marked by the red circle. The 100-year floodplain is marked as the shaded "Zone A" region on the map below.



6) Does the proposal involve any discharges of waste materials to surface waters? If so, describe the type of waste and anticipated volume of discharge.

Cooling water blowdown will be discharged. Although the exact amount has yet to be determined and will be confirmed during detailed design, it is expected to be on the order of less than 2% (up to 200 gpm).

b. Ground:

1) Will ground water be withdrawn, or will water be discharged to ground water? Give general description, purpose, and approximate quantities if known.

No.

2) Describe waste material that will be discharged into the ground from septic tanks or other sources, if any (for example: Domestic sewage; industrial, containing the following chemicals. . . ; agricultural; etc.). Describe the general size of the system, the number of such systems, the number of houses to be served (if applicable), or the number of animals or humans the system(s) are expected to serve.

Does not apply.

c. Water runoff (including stormwater):

1) Describe the source of runoff (including storm water) and method of collection and disposal, if any (include quantities, if known). Where will this water flow? Will this water flow into other waters? If so, describe.

Storm water will continue to be collected and routed to the process sewer as presently done.

2) Could waste materials enter ground or surface waters? If so, generally describe.

Ash from the boiler will be collected in a covered system and then transported by truck to the inert solid waste site. This material is not expected to enter ground or surface water.

c. Proposed measures to reduce or control surface, ground, and runoff water impacts, if any:

See c.1

4. **Plants**

a. Check or circle types of vegetation found on the site: **the project area is in middle of the mill site & any vegetation is minimal.**

———— deciduous tree: alder, maple, aspen, other

———— evergreen tree: fir, cedar, pine, other

———— shrubs

________grass

———— pasture

———— crop or grain

———— wet soil plants: cattail, buttercup, bullrush, skunk cabbage, other

———— water plants: water lily, eelgrass, milfoil, other

———— other types of vegetation

b. What kind and amount of vegetation will be removed or altered?

None.

c. List threatened or endangered species known to be on or near the site.

Unknown.

d. Proposed landscaping, use of native plants, or other measures to preserve or enhance vegetation on the site, if any:

None.

5. **Animals**

a. Circle any birds and animals which have been observed on or near the site or are known to be on or near the site (Animals in bold have been observed in the surrounding area):

birds: **hawk, heron, eagle, songbirds**, other:
mammals: **deer**, bear, elk, **beaver**, other:
fish: **bass, salmon, trout, herring, shellfish**, other:

There are a number of birds, mammals and marine fish and shellfish are known to inhabit Glen Cove, Port Townsend Bay. The animals indicated above are known to inhabit the surrounding area, but not necessarily at the site of the project.

b. List any threatened or endangered species known to be on or near the site.

PTPC is unaware of any state threatened or endangered species that inhabit the area around the site.

c. Is the site part of a migration route? If so, explain.

Unknown.

d. Proposed measures to preserve or enhance wildlife, if any:

No proposed measures.

6. **Energy and natural resources**

a. What kinds of energy (electric, natural gas, oil, wood stove, solar) will be used to meet the completed project's energy needs? Describe whether it will be used for heating, manufacturing, etc.

Hog fuel will be used to generate electricity in the completed project.

b. Would your project affect the potential use of solar energy by adjacent properties? If so, generally describe.

No.

c. What kinds of energy conservation features are included in the plans of this proposal? List other proposed measures to reduce or control energy impacts, if any:

None.

7. **Environmental health**

a. Are there any environmental health hazards, including exposure to toxic chemicals, risk of fire and explosion, spill, or hazardous waste, that could occur as a result of this proposal? If so, describe.

No.

1) Describe special emergency services that might be required.

No additional emergency services than already exist on-site will be required as a result of this project.

2) Proposed measures to reduce or control environmental health hazards, if any:

Does not apply.

b. **Noise**

1) What types of noise exist in the area which may affect your project (for example: traffic, equipment, operation, other)?

Does not apply.

2) What types and levels of noise would be created by or associated with the project on a short-term or a long-term basis (for example: traffic, construction, operation, other)? Indicate what hours noise would come from the site.

Typical construction noise which will not be louder than typical industrial noise.

3) Proposed measures to reduce or control noise impacts, if any:
None.

8. **Land and shoreline use**

a. What is the current use of the site and adjacent properties?

Industrial site – pulp and paper mill.

b. Has the site been used for agriculture? If so, describe.
No.

c. Describe any structures on the site.
Boiler buildings, Kraft pulp mill buildings, paper machines, offices, mechanical and maintenance buildings.

d. Will any structures be demolished? If so, what?
There will be a certain amount of removal/replacement/modification of existing equipment and/or "structure" associated with the cogeneration project. However, no wholesale demolition of a single structure is expected.

e. What is the current zoning classification of the site?
Heavy Industrial.

f. What is the current comprehensive plan designation of the site?
Heavy Industrial (HI) from Jefferson County Comprehensive Plan (2003).

g. If applicable, what is the current shoreline master program designation of the site?
High Intensity Shoreline per the Shoreline Master Program (2010)

h. Has any part of the site been classified as an "environmentally sensitive" area? If so, specify.
According to Jefferson County's online jMap portal, the project area has the following sensitivities: Seismic Hazard, SIPZ, Port Townsend Bay Tidelands/Wetland (Composite(DNR,NWI,SCS))

i. Approximately how many people would reside or work in the completed project?
No additional people planned at this time.

j. Approximately how many people would the completed project displace?
None.

k. Proposed measures to avoid or reduce displacement impacts, if any:
Does not apply.

l. Proposed measures to ensure the proposal is compatible with existing and projected land uses and plans, if any:

Does not apply.

9. **Housing**

a. Approximately how many units would be provided, if any? Indicate whether high, middle, or low-income housing.

Does not apply.

b. Approximately how many units, if any, would be eliminated? Indicate whether high, middle, or low-income housing.

Does not apply.

c. Proposed measures to reduce or control housing impacts, if any:

Does not apply.

10. **Aesthetics**

a. What is the tallest height of any proposed structure(s), not including antennas; what is the principal exterior building material(s) proposed?

A new turbine building will be less than 50 feet in height. The exterior have a typical commercial/industrial shell.

b. What views in the immediate vicinity would be altered or obstructed?

New building will be grouped near existing boilers and should not obstruct neighboring views.

c. Proposed measures to reduce or control aesthetic impacts, if any:

NA

11. **Light and glare**

a. What type of light or glare will the proposal produce? What time of day would it mainly occur?

Does not apply.

b. Could light or glare from the finished project be a safety hazard or interfere with views?

Does not apply.

c. What existing off-site sources of light or glare may affect your proposal?

Does not apply.

d. Proposed measures to reduce or control light and glare impacts, if any:

Does not apply.

12. **Recreation**

a. What designated and informal recreational opportunities are in the immediate vicinity?

Glen Cove, Port Townsend Bay provides fishing and boating recreational opportunities.

b. Would the proposed project displace any existing recreational uses? If so, describe.

No.

c. Proposed measures to reduce or control impacts on recreation, including recreation opportunities to be provided by the project or applicant, if any:

Does not apply.

13. **Historic and cultural preservation**

a. Are there any places or objects listed on, or proposed for, national, state, or local preservation registers known to be on or next to the site? If so, generally describe.

Unknown

b. Generally describe any landmarks or evidence of historic, archaeological, scientific, or cultural importance known to be on or next to the site.

Unknown. Much of the mill site is constructed on modified land (dirt and sand).

c. Proposed measures to reduce or control impacts, if any:

None.

14. **Transportation**

a. Identify public streets and highways serving the site, and describe proposed access to the existing street system. Show on site plans, if any.

Materials would be transported on Highway 19 and Highway 20 and turn onto Mill Road for delivery to the mill.

b. Is site currently served by public transit? If not, what is the approximate distance to the nearest transit stop?

No.

c. How many parking spaces would the completed project have? How many would the project eliminate?

Does not apply.

d. Will the proposal require any new roads or streets, or improvements to existing roads or streets, not including driveways? If so, generally describe (indicate whether public or private).

No.

e. Will the project use (or occur in the immediate vicinity of) water, rail, or air transportation? If so, generally describe.

The project will not use rail or air transportation. PTPC expects that the barge traffic may increase.

f. How many vehicular trips per day would be generated by the completed project? If known, indicate when peak volumes would occur.

As a result of the project, truck traffic to the PTPC facility will increase by 18%, which amounts to approximately 15 additional trucks per day, in addition to the approximately 82 trucks per day currently delivering raw materials to the mill.

g. Proposed measures to reduce or control transportation impacts, if any:

PTPC plans to bring biomass onsite by barge in addition to bringing biomass onsite by truck.

15. **Public services**

a. Would the project result in an increased need for public services (for example: fire protection, police protection, health care, schools, other)? If so, generally describe.

No.

b. Proposed measures to reduce or control direct impacts on public services, if any.

Does not apply.

16. **Utilities**

a. Circle utilities currently available at the site: electricity, natural gas, water, refuse service, telephone, sanitary sewer, septic system, other.

Natural gas and a septic system are not available onsite.

b. Describe the utilities that are proposed for the project, the utility providing the service, and the general construction activities on the site or in the immediate vicinity which might be needed.

The utilities will be unchanged as a result of this project.

C. SIGNATURE

The above answers are true and complete to the best of my knowledge. I understand that the lead agency is relying on them to make its decision.

Signature: ....[signature]..........

Date Submitted: ....6/15/2016..........

File Location: U:\30029.00\Drawings\Gen\Sketches\SK-Site.dwg

By: Thornton, Bill

Plot Date: 4/16/10

PRELIMINARY - NOT FOR CONSTRUCTION

Reference Drawings	
Drawing No	Title

Revisions			
Rev	Date	By	Description

Revisions			
Rev	Date	By	Description

Rev	Date	App'd	Client Approval Milestone

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Subconsultant:
Drawn: HGI/WGT Check:
Engr: Check:
Appr: PMgr:

EQUIPMENT LAYOUT
No.10 BOILER AREA

PORT TOWNSEND COGENERATION PLANT

Project No: 30029.00
Drawing: SK-30029/04
Rev: △

PRELIMINARY - NOT FOR CONSTRUCTION

Reference Drawings	
Drawing No	Title

Revisions			
Rev	Date	By	Description

Revisions			
Rev	Date	By	Description

Rev	Date	App'd	Client Approval Milestone

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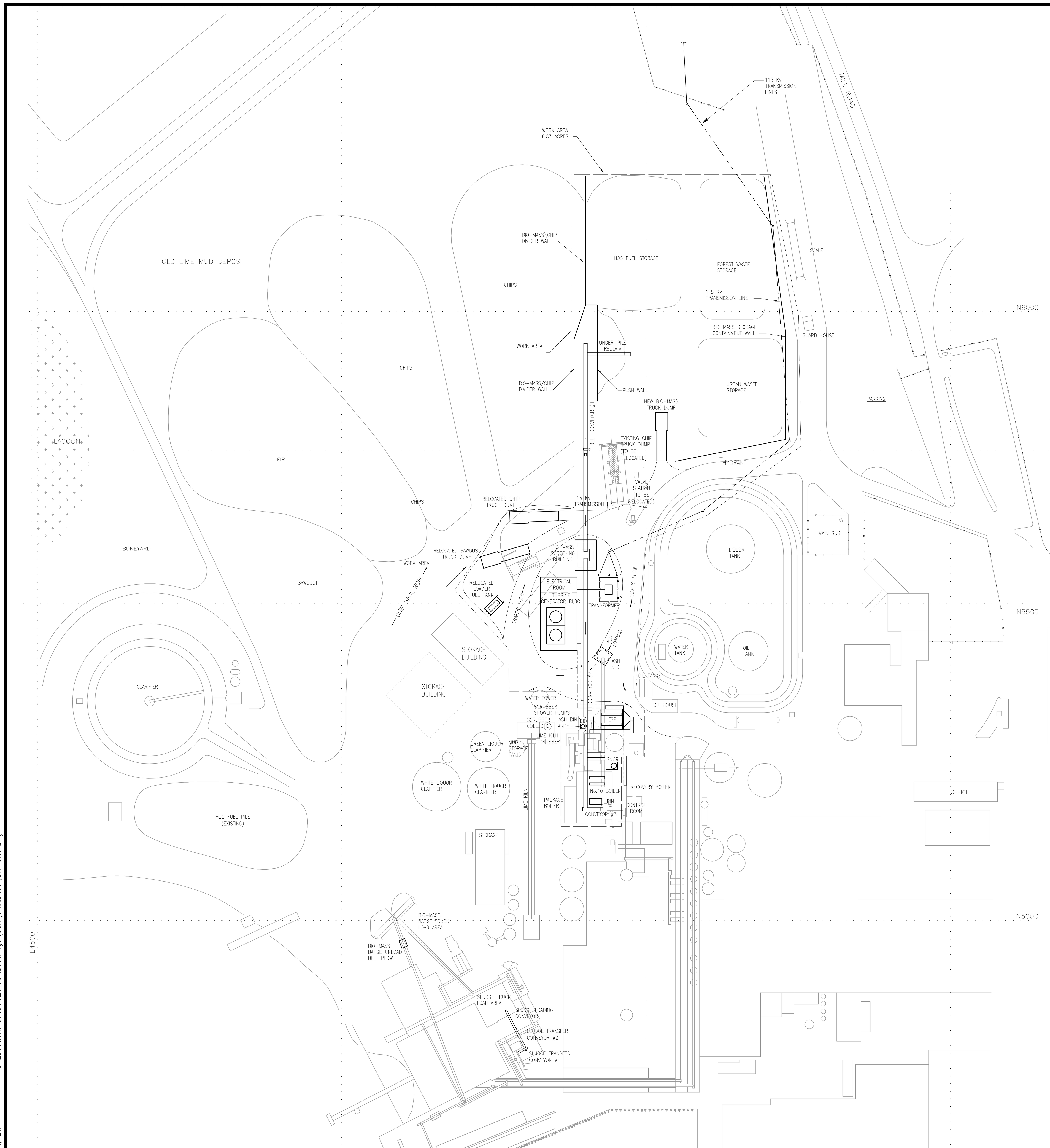
Subconsultant:
Drawn: HGI/WGT
Engr:
Appr:
Check:
Check:
PMgr:

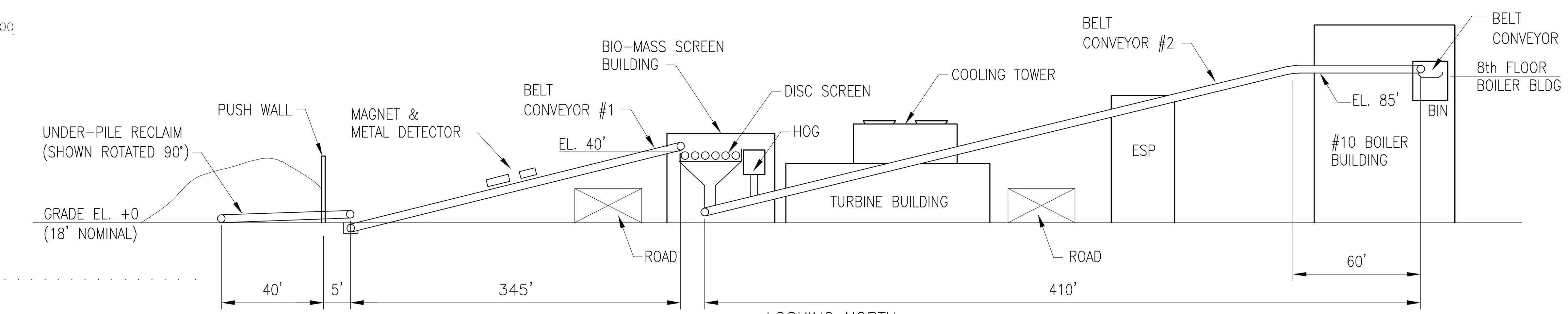
EQUIPMENT LAYOUT
TURBINE BUILDING AREA

PORT TOWNSEND COGENERATION PLANT

Project No: 30029.00
Drawing: SK-30029/03
Rev:

Plot Date: 4/15/10 By: Thornton, Bill File Location: U:\30029.00\Drawings\Gen\Sketches\SK-Site.dwg





LOOKING NORTH

ELEVATION

SCALE: NONE

0 100' 200'
1"=100'

PRELIMINARY - NOT FOR CONSTRUCTION

Reference Drawings		Revisions				Revisions			
Drawing No	Title	Rev	Date	By	Description	Rev	Date	By	Description

Rev	Date	App'd	Client Approval Milestone

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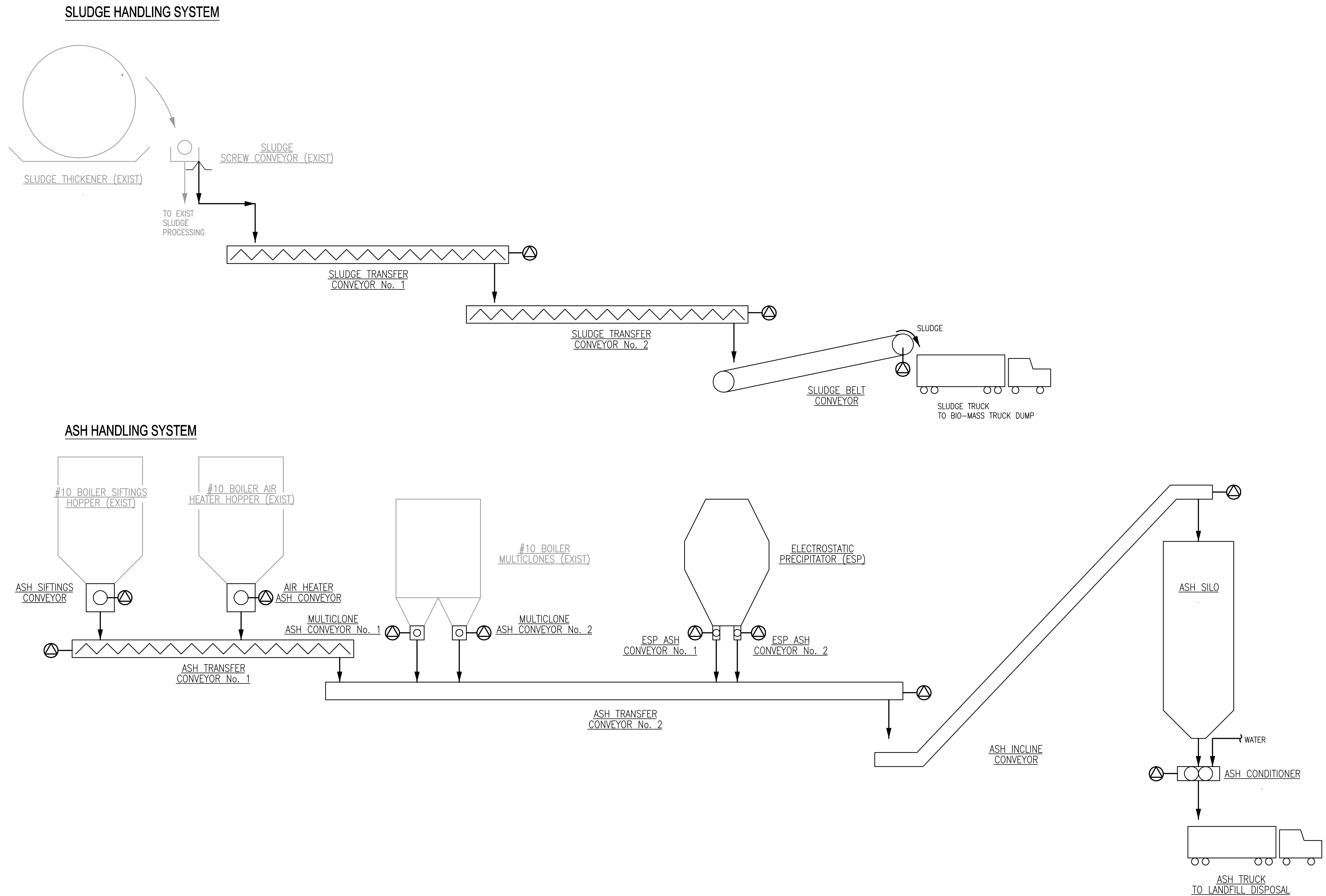
Subconsultant:
Drawn: HGI/WGT Check:
Engr: Check:
Appr: PMgr:

SITE PLAN AND ELEVATION

PORT TOWNSEND COGENERATION PLANT

Project No:	Drawing:	Rev:
30029.00	SK-30029/01	△

Plot Date: 4/16/10 By: Thornton, Bill File Location: U:\30029.00\Drawings\Gen\Sketches\SK-Site.dwg



GENERAL NOTES

1. NOT USED

KEYED NOTES

(1) NOT USED.

File Location: U:\30029.00\Drawings\Proc\Sketches\SK-30029-11.dwg

By: Thornton, Bill

Plot Date: 4/15/10

PRELIMINARY - NOT FOR CONSTRUCTION

Reference Drawings	
Drawing No	Title

Revisions			
Rev	Date	By	Description

Revisions			
Rev	Date	By	Description

Rev	Date	App'd	Client Approval Milestone

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Subconsultant:
Drawn: HGI/KE Check:
Engr: Check:
Appr: PMgr:

PROCESS FLOW DIAGRAM
ASH AND SLUDGE HANDLING SYSTEMS

PORT TOWNSEND COGENERATION PLANT

Project No: 30029.00
Drawing: SK-30029/11
Rev:

GENERAL NOTES

1. NOT USED

KEYED NOTES

(1) NOT USED.

PRELIMINARY - NOT FOR CONSTRUCTION

Reference Drawings		Revisions				Revisions			
Drawing No	Title	Rev	Date	By	Description	Rev	Date	By	Description

Rev	Date	App'd	Client Approval Milestone

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Subconsultant:
Drawn: HGI/KE Check:
Engr: Check:
Appr: PMgr:

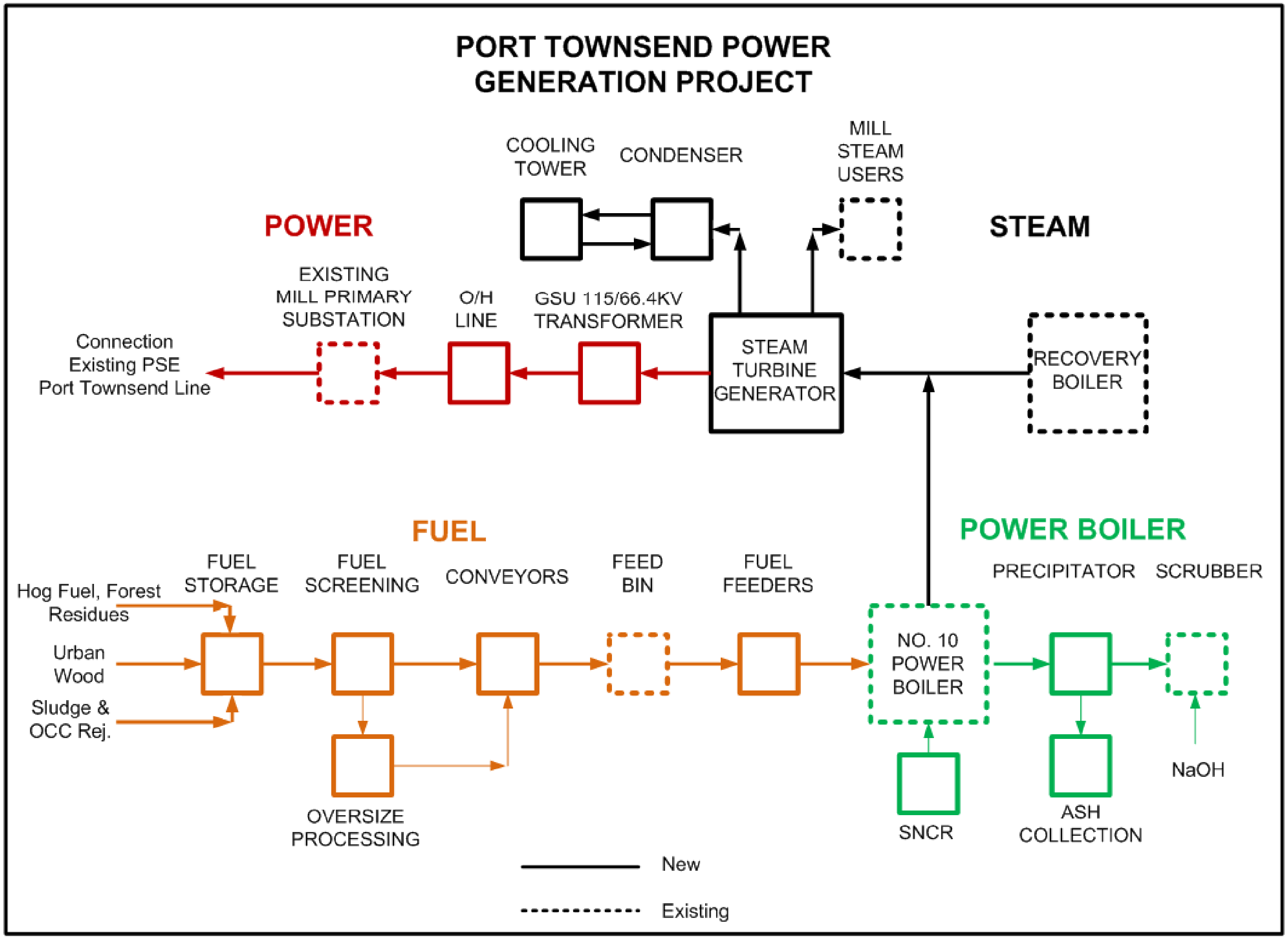
PROCESS FLOW DIAGRAM
BIO-MASS HANDLING SYSTEM

PORT TOWNSEND COGENERATION PLANT

Project No: 30029.00
Drawing: SK-30029/10
Rev:

File Location: U:\30029.00\Drawings\Proc\Sketches\SK-30029-10.dwg
By: Thornton, Bill
Plot Date: 4/15/10

Block Flow Diagram



APPENDIX B

EMISSIONS CALCULATIONS

Table B-1. Project Emissions Increase

Emission Unit	TSP (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)	TRS (tpy)	H_2S [a] (tpy)	H_2SO_4 (tpy)
Power Boiler 10 [b]	--	--	--	--	--	43.17	1.12	--	--	--
Recovery Furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower	1.32	1.32	1.32	--	--	--	--	--	--	--
Solid Fuel Handling Fugitives	0.05	0.03	0.00	--	--	--	--	--	--	--
Hog Fuel Haul Road Fugitives	4.75	1.32	0.13	--	--	--	--	--	--	--
Storage Pile Fugitives	0.85	0.43	0.43	--	--	--	--	--	--	--
Fly Ash Haul Road Fugitives	--	--	--	--	--	--	--	--	--	--
Total Emissions Increase [c]	**6.97**	**3.09**	**1.88**	**0.00**	**0.00**	**43.17**	**1.12**	**0.00**	**0.00**	**0.00**
Significant Emission Rate (SER)	25	15	10	40	40	100	40	10	10	7
Emission Increases Emissions < SER?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

[a] For the purpose of determining the total project increase, it is conservatively assumed that all TRS is emitted in the form of H_2S.

[b] It is expected that TSP, PM_{10}, and $PM_{2.5}$ emissions from the Power Boiler 10 will decrease as a result of the proposed dry ESP; SO_2, TRS, H_2S, and H_2SO_4 emissions from the Power Boiler 10 will decrease due the Power Boiler 10 firing less oil and increasing the effectiveness of the scrubber caustic solution; and NO_x emissions from the Power Boiler 10 will decrease due to the installation of SNCR. As a netting analysis is not performed for this project, PTPC is not taking credit for the emission decreases from TSP, PM_{10}, $PM_{2.5}$, SO_2, NO_x, TRS, H_2S, or H_2SO_4 from the Power Boiler 10.

[c] The emissions increase is calculated by subtracting the sum of the baseline actual emissions from the sum of the projected actual emissions affected by the project.

Table B-2. Power Boiler 10 and Recovery Furnace Annual Average Emissions

Baseline Period		Power Boiler 10 24 Month Annual Average Emissions (tpy)					Recovery Furnace 24 Month Annual Average Emissions (tpy)					Total - 24 Month Annual Average Emissions (tpy)				
Period Start	**Period End**	**TSP** [a]	**NO_x** [b]	**CO** [c]	**VOC** [d]	**TRS** [e]	**TSP** [f]	**NO_x** [g]	**CO** [h]	**VOC** [i]	**TRS** [j]	**TSP**	**NO_x**	**CO**	**VOC**	**TRS**
August 2004	July 2006	107.40	261.75	591.49	17.07	1.23	133.35	256.67	207.05	15.40	1.48	240.75	518.43	798.54	32.47	2.71
September 2004	August 2006	106.25	261.93	588.51	16.99	1.23	135.40	257.52	207.73	15.45	1.52	241.65	519.45	796.24	32.44	2.76
October 2004	September 2006	105.49	262.89	587.86	16.97	1.23	139.49	256.06	206.56	15.36	1.51	244.98	518.96	794.42	32.34	2.74
November 2004	October 2006	105.26	263.87	589.30	17.02	1.24	144.29	258.78	208.75	15.53	1.50	249.55	522.65	798.05	32.54	2.74
December 2004	November 2006	103.12	259.69	577.84	16.69	1.23	146.89	252.93	204.03	15.18	1.51	250.01	512.62	781.87	31.86	2.74
January 2005	December 2006	101.11	256.02	564.99	16.33	1.22	147.02	251.97	203.25	15.12	1.55	248.13	507.99	768.25	31.44	2.78
February 2005	January 2007	99.63	253.33	551.35	15.94	1.22	147.81	247.98	200.04	14.88	1.56	247.44	501.32	751.39	30.82	2.79
March 2005	February 2007	97.69	250.41	541.22	15.66	1.22	150.99	249.36	201.15	14.96	1.61	248.68	499.78	742.38	30.63	2.83
April 2005	March 2007	97.15	248.84	532.57	15.42	1.21	149.90	249.01	200.87	14.94	1.64	247.05	497.85	733.43	30.37	2.85
May 2005	April 2007	98.12	247.96	525.49	15.23	1.22	150.26	250.23	201.85	15.01	1.63	248.38	498.19	727.35	30.24	2.86
											Maximum	**250.01**	**522.65**	**798.54**	**32.54**	**2.86**
											Maximum Period Start	**December 2004**	**November 2004**	**August 2004**	**November 2004**	**May 2005**
											Maximum Period End	**November 2006**	**October 2006**	**July 2006**	**October 2006**	**April 2007**

a TSP emissions from the Power Boiler 10 are based on monthly sampling using EPA Method 5 as described in PTPC's Air Operating Permit No. WA 000092-2 , Condition D.1. Per 40 CFR 52.21(b)(48)(ii)(c), the average emission rate shall be adjusted downward to exclude any emissions that exceed an emission limit. The Power Boiler 10 is subject to a 0.10 lb PM/MMBtu emission factor, which was periodically exceeded during the baseline time period. Accordingly, the average emission rate was adjusted downward for periods in which emissions exceeded the permit limit, to levels that reflect the permitted emission factor. Refer to Table B-3 for more details on the PM adjustments.

b NOx emissions from the Power Boiler 10 are based on continuous emission monitoring as described in PTPC's Air Operating Permit No. WA 000092-2 , Condition D.4.

c CO emissions from the Power Boiler 10 are based on wood and oil usage as monitored by PTPC, and AP-42 emission factors as listed in AP-42 Table 1.6-2 (9/2003) for wood fuel and Table 1.3-1 (9/1998) for oil fuel.

d VOC emissions from the Power Boiler 10 are based on wood and oil usage as monitored by PTPC, and AP-42 emission factors as listed in AP-42 Table 1.6-3 (9/2003) for wood fuel and Table 1.3-3 (9/1998) for oil fuel.

e TRS emissions from the Power Boiler 10 are based on TRS concentration as determined by a 2/22/2006 source test conducted by Bighorn Environmental Air Quality, LLC and an 8/8/2000 source test conducted by Valid Results using monthly exhaust flows and hours of operation.

[f] TSP emissions from the Recovery Furnace are based on monthly sampling using EPA Method 5 as described in PTPC's Air Operating Permit No. WA 000092-2 , Condition A.2a.

[g] NO_x emissions from the Recovery Furnace are based on BLS firing rates as monitored by PTPC and NCASI emissions factors as listed in NCASI Technical Bulletin 884, Table 4.12 (8/2004) for NDCE Kraft recovery furnaces. Note that prior to 2007, air dried ton pulp (ADTP) throughput was used to calculate NO_x emissions, and BLS firing rates are not available prior to 2007. To maintain consistency, the ADTP throughput is converted to a BLS firing rate using a conversion factor of 1.6 ton BLS per ADTP, per NCASI Technical Bulletin 701, page 3.

[h] CO emissions from the Recovery Furnace are based on BLS firing rates as monitored by PTPC and NCASI emissions factors as listed in NCASI Technical Bulletin 884, Table 4.12 (8/2004) for NDCE Kraft recovery furnaces. Note that prior to 2007, air dried ton pulp (ADTP) throughput was used to calculate C emissions, and BLS firing rates are not available prior to 2007. To maintain consistency, the ADTP throughput is converted to a BLS firing rate using a conversion factor of 1.6 ton BLS per ADTP, per NCASI Technical Bulletin 701, page 3.

[i] VOC emissions from the Recovery Furnace are based on BLS firing rates as monitored by PTPC and NCASI emissions factors as listed in NCASI Technical Bulletin 884, Table 4.12 (8/2004) for NDCE Kraft recovery furnaces. Note that prior to 2007, air dried ton pulp (ADTP) throughput was used to calculate VOC emissions, and BLS firing rates are not available prior to 2007. To maintain consistency, the ADTP throughput is converted to a BLS firing rate using a conversion factor of 1.6 ton BLS per ADTP, per NCASI Technical Bulletin 701, page 3.

[j] TRS emissions from the Recovery Furnace are based on TRS concentration as determined by a TRS continuous emission monitor as described in PTPC's Air Operating Permit No. WA 000092-2, Condition A.14. Exhaust flow rates and hours of operation are also used in the emission calculation.

Table B-3. Power Boiler 10 Adjusted TSP Emissions

Baseline Period		Monthly TSP Emissions (ton/mo) [a]	Total Monthly Throughput (MMBtu/mo)	Actual TSP Emission Factor (lb/MMBtu) [b]	Adjusted TSP Monthly Emissions (ton/mo) [c]
Year	Month				
2004	December	14.14	225,570	0.13	11.28
2005	January	10.66	233,304	0.09	10.66
2005	February	9.17	194,525	0.09	9.17
2005	March	9.86	219,298	0.09	9.86
2005	April	7.68	218,644	0.07	7.68
2005	May	9.38	208,862	0.09	9.38
2005	June	9.41	217,923	0.09	9.41
2005	July	8.41	221,948	0.08	8.41
2005	August	5.45	227,166	0.05	5.45
2005	September	9.84	209,630	0.09	9.84
2005	October	9.18	207,306	0.09	9.18
2005	November	10.85	211,890	0.10	10.59
2005	December	9.73	232,740	0.08	9.73
2006	January	6.85	225,195	0.06	6.85
2006	February	8.55	193,860	0.09	8.55
2006	March	9.53	236,177	0.08	9.53
2006	April	5.46	209,769	0.05	5.46
2006	May	7.81	212,399	0.07	7.81
2006	June	8.52	230,952	0.07	8.52
2006	July	8.30	221,215	0.08	8.30
2006	August	8.07	203,546	0.08	8.07
2006	September	8.07	195,195	0.08	8.07
2006	October	8.00	183,656	0.09	8.00
2006	November	6.43	129,305	0.10	6.43

[a] TSP emissions are based on monthly sampling using EPA Method 5 as described in PTPC's Air Operating Permit No. WA 000092-2 , Condition D.1.

[b] The actual TSP emission factor is calculated as follows: Monthly TSP Emissions (ton/mo) * 2000 (lbs/ton) / Monthly Throughput (MMBtu/mo)

[c] Per PTPC's Air Operating Permit No. WA 000092-2, Condition D.1, the Power Boiler 10 is subject to an emission factor of 0.10 lb/MMBtu. Per 40 CFR 52.21(b)(48)(ii)(c), the average emission rate shall be adjusted downward to exclude any emissions that exceed an emission limit. Because the permitted emission factor (0.10 lb/MMBtu) was periodically exceeded during the baseline time period, emissions need to be readjusted. Accordingly, the average emission rate was adjusted downward if the actual TSP emission factor exceeds 0.10 lb/MMBtu.

Table B-4. Power Boiler 10 and Recovery Furnace Annual Average SO2 Emissions

Month [b]	Flow Rate (sdcfm)	Power Boiler 10 Non-NCG Firing [a]			Power Boiler 10 NCG Firing [a]			Recovery Furnace	Total SO_2 Emissions (tons) [f]
		Non-NCG Operating Days	Non-NCG SO_2 Concentration (ppm) [c]	Non-NCG SO_2 Emissions (tons) [d]	NCG Operating Days	NCG SO_2 Concentration (ppm) [c]	NCG SO_2 Emissions (tons) [d]	SO_2 Emissions [e] (tons)	
January 2008	120,859	25.0	7.74	3.0	5.1	27.9	2.2	0.4	5.6
February 2008	119,451	18.4	7.74	2.2	8.3	27.9	3.5	0.3	6.1
March 2008	111,527	18.9	7.74	2.1	11.4	27.9	4.6	0.4	7.1
April 2008	113,020	12.5	7.74	1.4	16.3	27.9	6.6	0.4	8.4
May 2008	113,488	16.5	7.74	1.9	14.3	27.9	5.8	0.4	8.1
June 2008	106,113	6.0	7.74	0.6	15.1	27.9	5.8	0.4	6.8
July 2008	109,362	9.7	7.74	1.1	20.6	27.9	8.1	0.4	9.5
August 2008	113,413	13.8	7.74	1.6	15.5	27.9	6.3	0.4	8.3
September 2008	137,869	14.4	7.74	2.0	12.8	27.9	6.3	0.4	8.7
October 2008	143,081	8.2	7.74	1.2	19.6	27.9	10.1	0.3	11.5
November 2008	93,191	2.1	7.74	0.2	27.9	27.9	9.3	0.4	9.9
December 2008	107,065	3.0	7.74	0.3	26.0	27.9	10.0	0.3	10.5
January 2009	128,480	2.4	7.74	0.3	25.8	27.9	11.9	0.7	12.9
February 2009	129,991	9.2	7.74	1.2	17.0	27.9	7.9	0.7	9.8
March 2009	126,781	6.9	7.74	0.9	23.9	27.9	10.9	0.8	12.5
April 2009	123,572	10.4	7.74	1.3	18.5	27.9	8.2	0.8	10.2
May 2009	128,222	11.6	7.74	1.5	19.0	27.9	8.7	0.8	11.0
June 2009	126,341	15.5	7.74	1.9	7.7	27.9	3.5	0.7	6.2
July 2009	128,795	23.1	7.74	3.0	7.7	27.9	3.5	1.1	7.6
August 2009	118,606	24.1	7.74	2.8	6.9	27.9	2.9	1.1	6.9
September 2009	116,371	16.1	7.74	1.9	9.3	27.9	3.9	1.1	6.8
October 2009	116,333	14.2	7.74	1.6	13.7	27.9	5.7	1.1	8.5
November 2009	128,992	21.6	7.74	2.8	8.2	27.9	3.8	1.2	7.7
December 2009	123,670	10.7	7.74	1.3	19.8	27.9	8.8	1.2	11.3
24 month Annual Average:				**18.9**			**79.1**	**7.9**	**105.9**

[a] The Power Boiler 10 periodically fires Non-Condensible Gases (NCGs) throughout the year in addition to various fuels. Stack test information is not available to estimate the effects NCG firing has on SO_2 emissions. As such, it is necessary to take stack test results of SO_2 emissions and add in an estimated amount of SO_2 emissions that are attributable to NCG firing.

[b] The time period from January 2008 through December 2009 is used to determine baseline SO_2 emissions.

[c] The non-NCG SO_2 concentration is the average of three Power Boiler 10 stack tests performed by Bighorn Environmental Air Quality, LLC on February 22, 2006. The NCG SO_2 concentration is estimated based on a 2001 study on the NCG effects on SO_2 emissions performed by PTPC. This study showed an incremental 20.2 ppmv increase in SO_2 when firing NCGs. To estimate the concentration when firing NCGs, the results of the Bighorn stack tests (7.74 ppmv) are added to the incremental increase (20.2 ppmv).

d SO2 emissions from the Power Boiler 10 are calculated using the following equation: flow rate (sdcfm) * 60 (min/hr) * 24 (hr/day) * operating days (days/month) * 64 (lbs SO2/lb-mol) * concentration (ppmv) / 106 / 359.1 (ft3/lb-mol) / 2000 (lb/ton)

[e] SO_2 emissions from the Recovery Furnace are based on monthly source testing as described in PTPC's Air Operating Permit No. WA 000092-2 , Condition A.6a.

f Total baseline SO2 emissions from the Power Boiler 10 and the Recovery Furnace are calculated by taking the sum of the non-NCG SO2 emissions from the Power Boiler 10, the NCG SO2 emissions from the Power Boiler 10, and the SO2 emissions from the Recovery Furnace.

Table B-5. Potential Throughput for Power Boiler 10

Affected Units	**Potential Annual Throughput**	
Power Boiler 10 [a]	3,626,640	MMBtu/yr

[a] The Power Boiler 10 will have a maximum firing rate of 414 MMBtu/hr. It is assumed that the unit will operate 365 days per year.

Table B-6. TSP Baseline Actual Emissions Summary

Units		Baseline Actual Emissions [a] (tpy)
Power Boiler 10	b	103.12
Recovery Furnace	c	146.89
Solid Fuel Handling Fugitives	d	0.002
Hog Fuel Haul Road Fugitives	e	0.26
Storage Pile Fugitives	f	0.80
Fly Ash Haul Road Fugitives	e	4.15
Total Emissions:		**255.22**

[a] The baseline period for TSP was selected by taking the maximum annual TSP emissions (readjusted for any monthly exceedance of the 0.10 lb PM/MMBtu permit limit) during any 24-month period from 2004 - 2009. Therefore, the period from December 2004 to November 2006 was chosen as the baseline actual period for TSP.

b TSP emissions from the Power Boiler 10 are based on monthly sampling using EPA Method 5 as described in PTPC's Air Operating Permit No. WA 000092-2 , Condition D.1.

[c] TSP emissions from the Recovery Furnace are based on monthly sampling using EPA Method 5 as described in PTPC's Air Operating Permit No. WA 000092-2 , Condition A.2a.

[d] Details regarding the solid fuel handling baseline fugitive emission calculation can be found in Tables B-34 and B-35.

[e] Details regarding the haul road baseline fugitive emission calculation can be found in Tables B-37, B-38, B-39, and B-40.

[f] Details regarding the storage pile baseline fugitive emission calculation can be found in Table B-42.

Table B-7. TSP Projected Actual Emission Calculation

Units		Projected Actual Throughput (units/yr)	Emission Factor [a]	Projected Actual Emissions (tpy)
Power Boiler 10	b	3,626,640 MMBtu	0.015 lb/MMBtu	27.20
Recovery Furnace	c	same as baseline	same as baseline	146.89
Cooling Tower	d	--	--	1.32
Solid Fuel Handling Fugitives	e	--	--	0.06
Hog Fuel Haul Road Fugitives	f	--	--	5.01
Storage Pile Fugitives	g	--	--	1.65
Fly Ash Haul Road Fugitives	f	--	--	1.89
			Total Emissions:	**184.01**

[a] Emission factor based on design specifications, as provided by the Harris Group.

[b] The Power Boiler 10 will have a maximum firing rate of 414 MMBtu/hr after the project. It is assumed that the unit will operate 365 days per year.

[c] The modifications to the Recovery Furnace will not have an impact on emissions from the unit. As such, projected actual emissions from the Recovery Furnace are set equal to the baseline actual emissions for the Recovery Furnace.

[d] Details regarding the cooling tower projected actual emission calculation can be found in Table B-33.

[e] Details regarding the solid fuel handling projected actual fugitive emission calculation can be found in Tables B-34 and B-36.

[f] Details regarding the haul road projected actual fugitive emission calculation can be found in Tables B-37, B-38, B-39, and B-41.

[g] Details regarding the storage pile projected actual fugitive emission calculation can be found in Table B-43.

Table B-8. TSP Project Emissions Increase

		Emission Increase [a] (tpy)
Power Boiler 10	b	--
Recovery Furnace		0.00
Cooling Tower		1.32
Solid Fuel Handling Fugitives		0.05
Hog Fuel Haul Road Fugitives		4.75
Storage Pile Fugitives		0.85
Fly Ash Haul Road Fugitives	c	--
Total Emissions Increase		6.97

[a] Unless otherwise indicated, the emission increase is calculated as the projected actual emissions minus the baseline actual emissions.

[b] It is expected that TSP emissions from the Power Boiler 10 will decrease as a result of the proposed dry ESP. As a netting analysis is not performed for this project, PTPC is not taking credit for the emission decrease from the Power Boiler 10.

[c] It is expected that TSP fugitive emissions from fly ash haul roads will decrease with the project. As a netting analysis is not performed for this project, PTPC is not taking credit for the emission decrease from the fly ash haul roads.

Table B-9. PM_{10} Baseline Actual Emissions Summary

Units		Baseline Actual Emissions [a] (tpy)
Power Boiler 10	b	103.12
Recovery Furnace	c	146.89
Solid Fuel Handling Fugitives	d	0.001
Hog Fuel Haul Road Fugitives	e	0.05
Storage Pile Fugitives	f	0.40
Fly Ash Haul Road Fugitives	e	1.18
Total Emissions:		**251.64**

[a] The baseline period for PM_{10} was selected by taking the maximum annual PM_{10} emissions (readjusted for any monthly exceedance of the 0.10 lb PM/MMBtu permit limit) during any 24-month period from 2004 - 2009. Therefore, the period from December 2004 to November 2006 was chosen as the baseline actual period for PM_{10}.

b PM10 emissions are assumed to be equal to TSP emissions for the Power Boiler 10. TSP emissions from the Power Boiler 10 are based on monthly sampling using EPA Method 5 as described in PTPC's Air Operating Permit No. WA 000092-2 , Condition D.1.

[c] PM_{10} emissions are assumed to be equal to TSP emissions for the Recovery Furnace. TSP emissions from the Recovery Furnace are based on monthly sampling using EPA Method 5 as described in PTPC's Air Operating Permit No. WA 000092-2 , Condition A.2a.

[d] Details regarding the solid fuel handling baseline fugitive emission calculation can be found in Tables B-34 and B-35.

[e] Details regarding the haul road baseline fugitive emission calculation can be found in Tables B-37, B-38, B-39, and B-40.

[f] Details regarding the storage pile baseline fugitive emission calculation can be found in Table B-42.

Table B-10. PM_{10} Projected Actual Emission Calculation

Units		Projected Actual Throughput (units/yr)	Emission Factor [a]	Projected Actual Emissions (tpy)
Power Boiler 10	b	3,626,640 MMBtu	0.015 lb/MMBtu	27.20
Recovery Furnace	c	same as baseline	same as baseline	146.89
Cooling Tower	d	--	--	1.32
Solid Fuel Handling Fugitives	e	--	--	0.03
Hog Fuel Haul Road Fugitives	f	--	--	1.37
Storage Pile Fugitives	g	--	--	0.82
Fly Ash Haul Road Fugitives	f	--	--	0.54
			Total Emissions:	**178.17**

[a] Emission factor based on design specifications, as provided by the Harris Group.

[b] The Power Boiler 10 will have a maximum firing rate of 414 MMBtu/hr after the project. It is assumed that the unit will operate 365 days per year.

[c] The modifications to the Recovery Furnace will not have an impact on emissions from the unit. As such, projected actual emissions from the Recovery Furnace are set equal to the baseline actual emissions for the Recovery Furnace.

[d] Details regarding the cooling tower projected actual fugitive emission calculation can be found in Table B-33.

[e] Details regarding the solid fuel handling projected actual fugitive emission calculation can be found in Tables B-34 and B-36.

[f] Details regarding the haul road projected actual fugitive emission calculation can be found in Tables B-37, B-38, B-39, and B-41.

[g] Details regarding the storage pile projected actual fugitive emission calculation can be found in Table B-43.

Table B-11. PM_{10} Project Emissions Increase

		Emission Increase [a] (tpy)
Power Boiler 10	b	--
Recovery Furnace		0.00
Cooling Tower		1.32
Solid Fuel Handling Fugitives		0.03
Hog Fuel Haul Road Fugitives		1.32
Storage Pile Fugitives		0.43
Fly Ash Haul Road Fugitives	c	**--**
Total Emissions Increase		3.09

[a] Unless otherwise indicated, the emission increase is calculated as the projected actual emissions minus the baseline actual emissions.

[b] It is expected that PM_{10} emissions from the Power Boiler 10 will decrease as a result of the proposed dry ESP. As a netting analysis is not performed for this project, PTPC is not taking credit for the emission decrease from the Power Boiler 10.

[c] It is expected that PM_{10} fugitive emissions from fly ash haul roads will decrease with the project. As a netting analysis is not performed for this project, PTPC is not taking credit for the emission decrease from the fly ash haul roads.

Table B-12. $PM_{2.5}$ Baseline Actual Emissions Summary

Units		Baseline Actual Emissions [a] (tpy)
Power Boiler 10	b	103.12
Recovery Furnace	c	146.89
Solid Fuel Handling Fugitives	d	0.0001
Hog Fuel Haul Road Fugitives	e	0.01
Storage Pile Fugitives	f	0.40
Fly Ash Haul Road Fugitives	e	0.12
Total Emissions:		**250.54**

[a] The baseline period for $PM_{2.5}$ was selected by taking the maximum annual $PM_{2.5}$ emissions (readjusted for any monthly exceedance of the 0.10 lb PM/MMBtu permit limit) during any 24-month period from 2004 - 2009. Therefore, the period from December 2004 to November 2006 was chosen as the baseline actual period for $PM_{2.5}$.

b PM2.5 emissions are assumed to be equal to TSP emissions for the Power Boiler 10. TSP emissions from the Power Boiler 10 are based on monthly sampling using EPA Method 5 as described in PTPC's Air Operating Permit No. WA 000092-2 , Condition D.1.

[c] $PM_{2.5}$ emissions are assumed to be equal to TSP emissions for the Recovery Furnace. TSP emissions from the Recovery Furnace are based on monthly sampling using EPA Method 5 as described in PTPC's Air Operating Permit No. WA 000092-2 , Condition A.2a.

[d] Details regarding the solid fuel handling baseline fugitive emission calculation can be found in Tables B-34 and B-35.

[e] Details regarding the haul road baseline fugitive emission calculation can be found in Tables B-37, B-38, B-39, and B-40.

[f] Details regarding the storage pile baseline fugitive emission calculation can be found in Table B-42.

Table B-13. $PM_{2.5}$ Projected Actual Emission Calculation

Units		Projected Actual Throughput (units/yr)	Emission Factor [a]	Projected Actual Emissions (tpy)
Power Boiler 10	b	3,626,640 MMBtu	0.015 lb/MMBtu	27.20
Recovery Furnace	c	same as baseline	same as baseline	146.89
Cooling Tower	d	--	--	1.32
Solid Fuel Handling Fugitives	e	--	--	0.004
Hog Fuel Haul Road Fugitives	f	--	--	0.14
Storage Pile Fugitives	g	--	--	0.82
Fly Ash Haul Road Fugitives	f	--	--	0.05
			Total Emissions:	**176.43**

[a] Emission factor based on design specifications, as provided by the Harris Group.

[b] The Power Boiler 10 will have a maximum firing rate of 414 MMBtu/hr after the project. It is assumed that the unit will operate 365 days per year.

[c] The modifications to the Recovery Furnace will not have an impact on emissions from the unit. As such, projected actual emissions from the Recovery Furnace are set equal to the baseline actual emissions for the Recovery Furnace.

[d] Details regarding the cooling tower projected actual emission calculation can be found in Table B-33.

[e] Details regarding the solid fuel handling projected actual fugitive emission calculation can be found in Tables B-34 and B-36.

[f] Details regarding the haul road projected actual fugitive emission calculation can be found in Tables B-37, B-38, B-39, and B-41.

[g] Details regarding the storage pile projected actual fugitive emission calculation can be found in Table B-43.

Table B-14. $PM_{2.5}$ Project Emissions Increase

		Emission Increase [a] (tpy)
Power Boiler 10	b	--
Recovery Furnace		0.00
Cooling Tower		1.32
Solid Fuel Handling Fugitives		0.004
Hog Fuel Haul Road Fugitives		0.13
Storage Pile Fugitives		0.43
Fly Ash Haul Road Fugitives	c	--
Total Emissions Increase		1.88

[a] Unless otherwise indicated, the emission increase is calculated as the projected actual emissions minus the baseline actual emissions.

[b] It is expected that $PM_{2.5}$ emissions from the Power Boiler 10 will decrease as a result of the proposed dry ESP. As a netting analysis is not performed for this project, PTPC is not taking credit for the emission decrease from the Power Boiler 10.

[c] It is expected that $PM_{2.5}$ fugitive emissions from fly ash haul roads will decrease with the project. As a netting analysis is not performed for this project, PTPC is not taking credit for the emission decrease from the fly ash haul roads.

Table B-15. SO_2 Baseline Actual Emissions Summary

Units		Baseline Actual Emissions [a] (tpy)
Power Boiler 10	b	98.04
Recovery Furnace	c	7.88
Total Emissions:		**105.92**

[a] The time period from January 2008 to December 2009 was chosen as the baseline actual period for SO_2.

b The non-NCG SO2 emissions from the Power Boiler 10 are based on stack test results and NCG SO2 emissions from the Power Boiler 10 are based on a 2001 study on the NCG effects on SO2 emissions performed by PTPC.

[c] SO_2 emissions from the Recovery Furnace are based on monthly source testing as described in PTPC's Air Operating Permit No. WA 000092-2 , Condition A.6a.

Table B-16. SO_2 Projected Actual Emission Calculations

Units		Projected Actual Throughput (units/yr)	Emission Factor [a]	Projected Actual Emissions (tpy)
Power Boiler 10 - no NCG firing	b	1,813,320 MMBtu	0.025 lb/MMBtu	22.67
Power Boiler 10 - NCG firing	b	1,813,320 MMBtu	0.055 lb/MMBtu	49.87
Recovery Furnace	c	same as baseline	same as baseline	7.88
			Total Emissions:	**80.41**

[a] Emission factor based on design specifications, as provided by the Harris Group.

b The Power Boiler 10 will have a maximum firing rate of 414 MMBtu/hr after the project. It is assumed that the unit will operate 365 days per year. For conservatism, it has been assumed that Non-Condensible Gases (NCGs) will be fired in the Power Boiler 10 fifty percent of the time.

[c] The modifications to the Recovery Furnace will not have an impact on emissions from the unit. As such, projected actual emissions from the Recovery Furnace are set equal to the baseline actual emissions for the Recovery Furnace.

Table B-17. SO_2 Project Emissions Increase

		Emission Increase [a] (tpy)
Power Boiler 10	b	--
Recovery Furnace		0.00
Total Emissions Increase		0.00

[a] Unless otherwise indicated, the emission increase is calculated as the projected actual emissions minus the baseline actual emissions.

[b] It is expected that SO_2 emissions from the Power Boiler 10 will decrease due to the Power Boiler 10 firing less oil and increasing the effectiveness of the scrubber caustic solution. As a netting analysis is not performed for this project, PTPC is not taking credit for the emission decrease from the Power Boiler 10.

Table B-18. NO_x Baseline Actual Emissions Summary

Units		Baseline Actual Emissions [a] (tpy)
Power Boiler 10	[b]	263.87
Recovery Furnace	[c]	258.78
Total Emissions:		**522.65**

[a] The baseline period for NO_x was selected by taking the maximum annual NO_x emissions during any 24-month period from 2004 - 2009. Therefore, the period from November 2004 to October 2006 was chosen as the baseline actual period for NO_x.

[b] NO_x emissions from the Power Boiler 10 are based on continuous emission monitoring as described in PTPC's Air Operating Permit No. WA 000092-2 , Condition D.4.

[c] NO_x emissions from the Recovery Furnace are based on BLS firing rates as monitored by PTPC and NCASI emissions factors as listed in NCASI Technical Bulletin 884, Table 4.12 (8/2004) for NDCE Kraft recovery furnaces.

Table B-19. NO_x Projected Actual Emission Calculations

Units		Projected Actual Throughput (units/yr)	Emission Factor [a]	Projected Actual Emissions (tpy)
Power Boiler 10	[b]	3,626,640 MMBtu	0.13 lb/MMBtu	235.73
Recovery Furnace	[c]	same as baseline	same as baseline	258.78
			Total Emissions:	**494.52**

[a] Emission factor based on design specifications, as provided by the Harris Group.

[b] The Power Boiler 10 will have a maximum firing rate of 414 MMBtu/hr after the project. It is assumed that the unit will operate 365 days per year.

[c] The modifications to the Recovery Furnace will not have an impact on emissions from the unit. As such, projected actual emissions from the Recovery Furnace are set equal to the baseline actual emissions for the Recovery Furnace.

Table B-20. NO_x Project Emissions Increase

		Emission Increase [a] (tpy)
Power Boiler 10	[b]	--
Recovery Furnace		0.00
Total Emissions Increase		0.00

[a] Unless otherwise indicated, the emission increase is calculated as the projected actual emissions minus the baseline actual emissions.

[b] It is expected that NO_x emissions from the Power Boiler 10 will decrease due to the installation of SNCR. As a netting analysis is not performed for this project, PTPC is not taking credit for the emission decrease from the Power Boiler 10.

Table B-21. CO Baseline Actual Emissions Summary

Units		Baseline Actual Emissions [a] (tpy)
Power Boiler 10	b	591.49
Recovery Furnace	c	207.05
Total Emissions:		**798.54**

[a] The baseline period for CO was selected by taking the maximum annual CO emissions during any 24-month period from 2004 - 2009. Therefore, the period from August 2004 to July 2006 was chosen as the baseline actual period for CO.

[b] CO emissions from the Power Boiler 10 are based on wood and oil usage as monitored by PTPC. AP-42 emission factors for CO are listed in AP-42 Table 1.6-2 (9/2003) as 0.60 lb/MMBtu for wood fuel, and in Table 1.3-1 (9/1998) as 5 lb/10^3 gal for oil fuel.

[c] CO emissions from the Recovery Furnace are based on BLS firing rates as monitored by PTPC and NCASI emissions factors as listed in NCASI Technical Bulletin 884, Table 4.12 (8/2004) for NDCE Kraft recovery furnaces.

Table B-22. CO Projected Actual Emission Calculation

Units		Projected Actual Throughput (units/yr)	Emission Factor [a]	Projected Actual Emissions (tpy)
Power Boiler 10	**b**	3,626,640 MMBtu	0.35 lb/MMBtu	634.66
Recovery Furnace	**c**	same as baseline	same as baseline	207.05
			Total Emissions:	**841.71**

[a] Emission factor based on design specifications, as provided by the Harris Group.

[b] The Power Boiler 10 will have a maximum firing rate of 414 MMBtu/hr after the project. It is assumed that the unit will operate 365 days per year.

[c] The modifications to the Recovery Furnace will not have an impact on emissions from the unit. As such, projected actual emissions from the Recovery Furnace are set equal to the baseline actual emissions for the Recovery Furnace.

Table B-23. CO Project Emissions Increase

	Emission Increase [a] (tpy)
Power Boiler 10	43.17
Recovery Furnace	0.00
Total Emissions Increase	43.17

[a] The emission increase is calculated as the projected actual emissions minus the baseline actual emissions.

Table B-24. VOC Baseline Actual Emissions Summary

Units	Baseline Actual Emissions [a] (tpy)
Power Boiler 10 [b]	17.02
Recovery Furnace [c]	15.53
Total Emissions:	**32.54**

[a] The baseline period for VOC was selected by taking the maximum annual VOC emissions during any 24-month period from 2004 - 2009. Therefore, the period from November 2004 to October 2006 was chosen as the baseline actual period for VOC.

[b] VOC emissions from the Power Boiler 10 are based on wood and oil usage as monitored by PTPC. AP-42 emission factors for VOCs are listed in AP-42 Table 1.6-3 (9/2003) as 0.017 lb/MMBtu for wood fuel and in Table 1.3-3 (9/1998) as 0.28 lb/10^3 gal for oil fuel.

[c] VOC emissions from the Recovery Furnace are based on BLS firing rates as monitored by PTPC and NCASI emissions factors as listed in NCASI Technical Bulletin 884, Table 4.12 (8/2004) for NDCE Kraft recovery furnaces.

Table B-25. VOC Projected Actual Emission Calculations

Units	Projected Actual Throughput (units/yr)	Emission Factor [a]	Projected Actual Emissions (tpy)
Power Boiler 10 [b]	3,626,640 MMBtu	0.010 lb/MMBtu	18.13
Recovery Furnace [c]	same as baseline	same as baseline	15.53
		Total Emissions:	**33.66**

[a] Emission factor based on design specifications, as provided by the Harris Group.

[b] The Power Boiler 10 will have a maximum firing rate of 414 MMBtu/hr after the project. It is assumed that the unit will operate 365 days per year.

[c] The modifications to the Recovery Furnace will not have an impact on emissions from the unit. As such, projected actual emissions from the Recovery Furnace are set equal to the baseline actual emissions for the Recovery Furnace.

Table B-26. VOC Project Emissions Increase

	Emission Increase [a] (tpy)
Power Boiler 10	1.12
Recovery Furnace	0.00
Total Emissions Increase	1.12

[a] The emission increase is calculated as the projected actual emissions minus the baseline actual emissions.

Table B-27. TRS Baseline Actual Emissions Summary

Units		Baseline Actual Emissions [a] (tpy)
Power Boiler 10	b	1.22
Recovery Furnace	c	1.63
Total Emissions:		**2.86**

[a] The baseline period for TRS was selected by taking the maximum annual TRS emissions during any 2-calendar year period from 2004 - 2009. Therefore, the period from May 2005 to April 2007 was chosen as the baseline actual period for TRS.

[b] TRS emissions from the Power Boiler 10 are based on TRS concentration as determined by a 2/22/2006 source test conducted by Bighorn Environmental Air Quality, LLC and an 8/8/2000 source test conducted by Valid Results using monthly exhaust flows and hours of operation.

[c] TRS emissions from the Recovery Furnace are based on TRS concentration as determined by a TRS continuous emission monitor as described in PTPC's Air Operating Permit No. WA 000092-2, Condition A.14. Exhaust flow rates and hours of operation are also used in the emission calculation.

Table B-28. TRS Projected Actual Emission Calculation

Units		Projected Actual Throughput (units/yr)	Emission Factor [a]	Projected Actual Emissions (tpy)
Power Boiler 10	**b**	1,813,320 MMBtu	0.0005 lb/MMBtu	0.45
Recovery Furnace	**c**	same as baseline	same as baseline	1.63
			Total Emissions:	**2.09**

[a] Emission factor based on design specifications, as provided by the Harris Group.

[b] The Power Boiler 10 will have a maximum firing rate of 414 MMBtu/hr after the project. It is assumed that the unit will operate 365 days per year. TRS emissions are only expected when Non-Condensible Gases (NCGs) are fired in the boiler. For conservatism, it has been assumed that NCGs will be fired in the Power Boiler 10 fifty percent of the time (414 MMBtu/hr * 50% * 8760 hrs/yr).

[c] The modifications to the Recovery Furnace will not have an impact on emissions from the unit. As such, projected actual emissions from the Recovery Furnace are set equal to the baseline actual emissions for the Recovery Furnace.

Table B-29. TRS Project Emissions Increase

		Emission Increase [a] (tpy)
Power Boiler 10	**b**	--
Recovery Furnace		0.00
Total Emissions Increase		0.00

[a] Unless otherwise indicated, the emission increase is calculated as the projected actual emissions minus the baseline actual emissions.

1.63

Table B-30. H_2SO_4 Baseline Actual Emissions Summary

Units		Baseline Actual Throughput (units/yr)	Emission Factor	Baseline Actual Emissions [a] (tpy)
Power Boiler 10	b	--	--	7.43
Recovery Furnace	c	311,468 ton BLS	0.0293 lb/t BLS	4.56
Total Emissions:				**11.99**

[a] The time period from January 2008 to December 2009 was chosen as the baseline actual period for H_2SO_4.

[b] H_2SO_4 emissions data for hog fuel boilers is not readily available. AP-42 Chapter 1.3, Section 1.3.3.2 indicates that, on average, more than 95 percent of the fuel sulfur in fuel oil is converted to SO_2, about 1 to 5 percent is further oxidized to sulfur trioxide (SO_3) and 1 to 3 percent is emitted as sulfate particulate. SO_3 readily reacts with water vapor (both in the atmosphere and in flue gas) to form a sulfuric acid mist. Due to the lack of data available for H_2SO_4 emissions from hog fuel, it is conservatively assumed that 5 percent of SO_2 baseline emissions from the Power Boiler 10 is converted to H_2SO_4 emissions in the atmosphere or flue gas. It is expected that less than 5 percent of fuel-bound sulfur would be emitted as H_2SO_4, since hog fuel is naturally more alkaline than fuel oil. Also, the existing caustic wet scrubber may reduce the creation of H_2SO_4. Therefore, the H_2SO_4 emission rate presented represents an upper bound on baseline H_2SO_4 emissions.

[c] The baseline H_2SO_4 emissions from the Recovery Furnace are calculated using the baseline black liquor solid (BLS) throughput at the Recovery Furnace and the sulfuric acid emission factor for non-direct contact evaporator (NDCE) Recovery Furnaces provided in NCASI Technical Bulletin No. 973, Table 4.23, dated February 2010. The maximum of the mean and median emission factors is used.

Table B-31. H_2SO_4 Projected Actual Emission Calculation

Units		Projected Actual Throughput (units/yr)	Emission Factor	Projected Actual Emissions (tpy)
Power Boiler 10	a	--	--	1.72
Recovery Furnace	b	same as baseline	same as baseline	4.56
			Total Emissions:	**6.28**

[a] The same methodology that is used to calculate baseline H_2SO_4 emissions from the Power Boiler 10 is used to calculate projected actual H_2SO_4 emissions from the Power Boiler 10. Therefore, it is conservatively assumed that 5 percent of SO_2 projected actual emissions is converted to H_2SO_4 emissions. It is assumed that the increased addition of caustic will similarly control SO_2 and H_2SO_4. As with baseline H_2SO_4 emissions, it is expected that less than 5 percent of fuel-bound sulfur would be emitted as H_2SO_4, since hog fuel is naturally more alkaline than fuel oil. Also, the existing caustic wet scrubber may reduce the creation of H_2SO_4. Therefore, the H_2SO_4 emission rate presented represents an upper bound on baseline H_2SO_4 emissions.

[b] The modifications to the Recovery Furnace will not have an impact on emissions from the unit. As such, projected actual emissions from the Recovery Furnace are set equal to the baseline actual emissions for the Recovery Furnace.

Table B-32. H_2SO_4 Project Emissions Increase

		Emission Increase [a] (tpy)
Power Boiler 10	b	--
Recovery Furnace		0.00
Total Emissions Increase		0.00

[a] Unless otherwise indicated, the emission increase is calculated as the projected actual emissions minus the baseline actual emissions.

[b] It is expected that H_2SO_4 emissions from the Power Boiler 10 will decrease due to increasing the effectiveness of the scrubber caustic solution. As a netting analysis is not performed for this project, PTPC is not taking credit for the emission decrease from the Power Boiler 10.

Table B-33. Cooling Tower Emission Calculations [a]

Unit Description	Water Circulation Rate [b] (gal/min)	Control Device [b]	Drift [b]	Maximum TDS Concentration [b] (ppm)	Potential PM Emission Rate [c] (tpy)
Cooling Tower	12,000	Mist Eliminator	0.001%	5,000	1.32

[a] A new cooling tower system will be installed with the project. The cooling tower system will contain two cells with its own fan. The calculations are for the total cooling tower system.
[b] Cooling tower parameters provided by the Harris Group.
[c] PM emissions (tons/yr) = (Throughput/Capacity [gal/min]) x (Maximum TDS Concentration [ppm]) / 10^6 x (Drift Rate [%]) x (8.35 [lb/gal]) / (2000 [lbs/ton]) x (60 [min/hr]) x (8,760 [hrs/yr]).

Table B-34. Solid Fuel Handling Operation Emission Factors

Transfer Description		Change with Project	Location [a] (Inside or Outside)	Emission Factor (lb/ton) [b]		
				PM	PM_{10}	$PM_{2.5}$
Barge Unloading System						
Barge Unloading Crane Bucket to Barge Elevated Conveyor	c	Associated increase at existing operation	outside	3.91E-05	1.85E-05	2.80E-06
Barge Elevated Conveyor to Chip Reclaim Conveyor	c	Associated increase at existing operation	outside	3.91E-05	1.85E-05	2.80E-06
Chip Reclaim Conveyor to Biomass Truck Loading	c	Associated increase at existing operation	outside	3.91E-05	1.85E-05	2.80E-06
Power Boiler 10 Solid Fuel Handling System						
Truck Dumper to Hog Fuel Pile	d	New operation	outside	3.91E-05	1.85E-05	2.80E-06
Loader to Reclaim Conveyor	d	New operation	outside	3.91E-05	1.85E-05	2.80E-06
Biomass Reclaim Conveyor to Biomass Belt Conveyor #1	d	New operation	outside	3.91E-05	1.85E-05	2.80E-06
Biomass Belt Conveyor #1 to Scale	d	New operation	outside	3.91E-05	1.85E-05	2.80E-06
Scale to Biomass Belt Conveyor #2	d	New operation	outside	3.91E-05	1.85E-05	2.80E-06
Biomass Belt Conveyor #2 to Biomass Belt Conveyor #3	d	New operation	outside	3.91E-05	1.85E-05	2.80E-06
Biomass Belt Conveyor #3 to Boiler Fuel Bin	d	New operation	inside	4.54E-06	2.15E-06	3.25E-07
Boiler Fuel Bin to Metering Belt	e	Associated increase at existing operation	inside	4.54E-06	2.15E-06	3.25E-07
Metering Belt to Flight Conveyor	e	Associated increase at existing operation	inside	4.54E-06	2.15E-06	3.25E-07
Flight Conveyor to Three Surge Bins	e	Associated increase at existing operation	inside	4.54E-06	2.15E-06	3.25E-07

[a] No control efficiency is assumed for "inside sources," however, the wind speed is adjusted to account for the effect of enclosure. The EPA document *Control of Open Fugitive Dust Sources*, September 1988, EPA-450/3-88-008, Section 4.3.2 recommends using a control efficiency of 60-80% for porous enclosures. However, this control efficiency is based on a wind speed reduction. As such, the wind speed adjustment effectively accounts for the control of enclosure for the "inside sources."

[b] Emission factors are calculated based on Equation 1 in AP-42 section 13.2.4 (Aggregate Handling and Storage Piles). The following values are used to calculate the emission factors:

Particle Size Multiplier (k) for PM:	0.74	Per AP-42 Section 13.2.4.3, table of Aerodynamic Particle Size Multiplier (k) for Equation 1.
Particle Size Multiplier (k) for PM_{10}:	0.35	Per AP-42 Section 13.2.4.3, table of Aerodynamic Particle Size Multiplier (k) for Equation 1.
Particle Size Multiplier (k) for $PM_{2.5}$:	0.053	Per AP-42 Section 13.2.4.3, table of Aerodynamic Particle Size Multiplier (k) for Equation 1.
Mean Wind Speed (U), outside, mph:	6.82	Average annual wind speed, based on 2009 meteorological data for the Port Angeles meteorological station, the nearest station to the Port Townsend facility.
Mean Wind Speed (U), inside, mph:	1.3	Per AP-42 Section 13.2.4.3, table of Ranges of Source Conditions for Equation 1, low end of range, selected to represent indoor conditions.
Material Moisture Content (M), %:	50	Moisture content ranges from 30% to 70%, depending on fuel source and time of year. An average moisture content of 50% is used.

[c] The existing barge unloading system will continue to operate following the project and will experience an increase in hog fuel throughput. In the barge handling system, the barge unloading crane removes biomass from the barge and transfers it to the barge elevated conveyor. Biomass is then transferred onto the chip reclaim conveyor. From this conveyor, hog fuel is dropped onto biomass trucks or the chip reclaim system. For emission calculation purposes, it is assumed that all biomass is transported via truck to the hog fuel storage pile.

d A new solid fuel handling system will be installed to transport solid fuel from the truck dumper to the Power Boiler 10 building. In the new solid fuel handling system, hog fuel, OCC rejects, sludge, sawdust, and chips are dumped onto the hog fuel pile at the truck dump. From this point, solid fuel is transferred to the biomass reclaim conveyor via a loader. Solid fuel is transferred from the biomass reclaim conveyor to the biomass belt conveyor to a scale and biomass sorter located under a canopy. From here, solid fuel is transferred to biomass belt conveyor #2 to biomass belt conveyor #3.

e The solid fuel handling system located inside the Power Boiler 10 building will continue to operate following the project and will experience an increase in solid fuel throughput. The new biomass belt conveyor #3 will transport solid fuel inside of the Power Boiler 10 building to the existing boiler fuel bin. Solid fuel drops out of the day bin onto the metering belt inside of the day bin. From the metering belt, solid fuel is transferred to the flight conveyor then to three surge bins. Following the project, the surge bins will feed the boiler's new compressed air based feed system.

Table B-35. Baseline Solid Fuel Handling Emissions

Solid Fuel Handling Operation	Change with Project	Baseline Solid Fuel Throughput (wet tons/year)	Emission Rate (tpy) [a]		
			PM	PM_{10}	$PM_{2.5}$
Barge Unloading System					
Barge Unloading Crane Bucket to Barge Elevated Conveyor [b]	Associated increase at existing operation	7,800	0.0002	0.0001	0.00001
Barge Elevated Conveyor to Chip Reclaim Conveyor [b]	Associated increase at existing operation	7,800	0.0002	0.0001	0.00001
Chip Reclaim Conveyor to Biomass Truck Loading [b]	Associated increase at existing operation	7,800	0.0002	0.0001	0.00001
Power Boiler 10 Solid Fuel Handling System					
Truck Dumper to Hog Fuel Pile [c]	New operation	0	0.000	0.000	0.0000
Loader to Reclaim Conveyor [c]	New operation	0	0.000	0.000	0.0000
Biomass Reclaim Conveyor to Biomass Belt Conveyor #1 [c]	New operation	0	0.000	0.000	0.0000
Biomass Belt Conveyor #1 to Scale [c]	New operation	0	0.000	0.000	0.0000
Scale to Biomass Belt Conveyor #2 [c]	New operation	0	0.000	0.000	0.0000
Biomass Belt Conveyor #2 to Biomass Belt Conveyor #3 [c]	New operation	0	0.000	0.000	0.0000
Biomass Belt Conveyor #3 to Boiler Fuel Bin [c]	New operation	0	0.000	0.000	0.0000
Boiler Fuel Bin to Metering Belt [d]	Associated increase at existing operation	214,544	0.0005	0.0002	0.00003
Metering Belt to Flight Conveyor [d]	Associated increase at existing operation	214,544	0.0005	0.0002	0.00003
Flight Conveyor to Three Surge Bins [d]	Associated increase at existing operation	214,544	0.0005	0.0002	0.00003
Total			0.0019	0.0009	0.0001

[a] The potential emission rates are calculated using the potential fuel throughput for each operation and the emission factors calculated in Table B-34

[b] Prior to the project, approximately 5% of hog fuel was received by barge. This amounts to approximately 3,900 bone dry tons (BDT) per year of hog fuel received by barge during the baseline period. A moisture content of 50% is used to convert BDT of hog fuel to as-transported (i.e., wet) hog fuel.

c The portion of the solid fuel handling system located outside of the Power Boiler 10 building will be replaced as a part of the project. Therefore, baseline emissions from the truck dumper to biomass belt conveyor #3 are equal to zero.

d The solid fuel handling system located inside the Power Boiler 10 building will continue to operate following the project and will experience an increase in solid fuel throughput. The baseline solid fuel throughput (on an as-transported basis) is equal to the 24-month annual average solid fuel throughput fired in the Power Boiler 10 from December 2004 to November 2006, which is the baseline period selected for TSP/PM10/PM2.5 emissions. During the baseline period, hog fuel, sludge, and OCC rejects were transported to the boiler from the boiler fuel bin; as such, the solid fuel throughput includes hog fuel, sludge, and OCC rejects. A moisture content of 50% is used to convert bone dry units (BDU) of solid fuel to as-transported (i.e., wet) fuel.

Table B-36. Future Potential Solid Fuel Handling Emissions

Solid Fuel Handling Operation		Change with Project	Future Potential Solid Fuel Throughput (wet tons/year)	Emission Rate (tpy) [a]		
				PM	PM_{10}	$PM_{2.5}$
Barge Unloading System						
Barge Unloading Crane Bucket to Barge Elevated Conveyor	b	Associated increase at existing operation	78,800	0.0015	0.0007	0.0001
Barge Elevated Conveyor to Chip Reclaim Conveyor	b	Associated increase at existing operation	78,800	0.0015	0.0007	0.0001
Chip Reclaim Conveyor to Biomass Truck Loading	b	Associated increase at existing operation	78,800	0.0015	0.0007	0.0001
Power Boiler 10 Solid Fuel Handling System						
Truck Dumper to Hog Fuel Pile	c	New operation	412,118	0.0081	0.0038	0.0006
Loader to Reclaim Conveyor	c	New operation	412,118	0.0081	0.0038	0.0006
Biomass Reclaim Conveyor to Biomass Belt Conveyor #1	c	New operation	412,118	0.0081	0.0038	0.0006
Biomass Belt Conveyor #1 to Scale	c	New operation	412,118	0.0081	0.0038	0.0006
Scale to Biomass Belt Conveyor #2	c	New operation	412,118	0.0081	0.0038	0.0006
Biomass Belt Conveyor #2 to Biomass Belt Conveyor #3	c	New operation	412,118	0.0081	0.0038	0.0006
Biomass Belt Conveyor #3 to Boiler Fuel Bin	c	New operation	412,118	0.0009	0.0004	0.0001
Boiler Fuel Bin to Metering Belt	c	Associated increase at existing operation	412,118	0.0009	0.0004	0.0001
Metering Belt to Flight Conveyor	c	Associated increase at existing operation	412,118	0.0009	0.0004	0.0001
Flight Conveyor to Three Surge Bins	c	Associated increase at existing operation	412,118	0.0009	0.0004	0.0001
Total				0.0567	0.0268	0.0041

[a] The potential emission rates are calculated using the potential solid fuel throughput for each operation and the emission factors calculated in Table B-34.

[b] Following the project, 10 - 20% of hog fuel was received by barge. For emission calculation purposes for the barge unloading system, it is conservatively assumed that 20% of the forecasted hog fuel throughput of 197,000 BDT will be received by barge. This amounts to approximately 39,400 BDT per year of hog fuel received by barge following the project. A moisture content of 50% is used to convert BDT of hog fuel to as-transported (i.e., wet) hog fuel.

[c] Following the project, hog fuel, sludge and OCC rejects will be transported through the entire solid fuel handling system. The following data is used to calculate the potential solid fuel throughput. A moisture content of 50% is used to convert BDU of solid fuel to as-transported (i.e., wet) fuel.

Maximum boiler heat input (MMBtu/yr):	3,626,640
Heating value of hog fuel (Btu/dry lb):	8,800

Table B-37. Material Transportation Information

Material Transported [a]	Baseline Material Throughput (tons/year)	Future Potential Material Throughput (tons/year)	Load Weight (tons/trip)	Vehicle Weight Empty (tons)	Vehicle Weight Loaded (tons)	Road Type [b]
Hog Fuel - Barge Unloading	-- [c]	78,800 [d]	25.0 [e]	10.0 [f]	35.0 [f]	Unpaved
Hog Fuel - Trucked from Offsite	148,200 [c]	315,200 [d]	25.0 [e]	10.0 [f]	35.0 [f]	Paved
Fly Ash - Baseline Period	-- [g]	--	4.7 [h]	33.6 [i]	38.3 [j]	20% Paved, 80% Unpaved
Fly Ash - Post Project	--	22,338 [k]	25.0 [e]	10.0 [f]	35.0 [f]	20% Paved, 80% Unpaved

[a] The hog fuel (barge unloading) route and the hog fuel (trucked from offsite) routes are existing material transport routes that will experience an increase in the number of annual trips traveled along the routes. The actual routes will not change as a result of the project. The fly ash route is an existing route. Fly ash is transported from the ash bunker to a landfill located on PTPC's property. Currently, fly ash is hauled the landfill in front end loaders. Following the project, fly ash will be hauled to the landfill in trucks. The amount of fly ash generated by the Power Boiler 10 will increase as a result of the project.

[b] Road types for hog fuel trucks provided by the Harris Group. Road type for fly ash truck provided by PTPC.

[c] The baseline hog fuel throughput is equal to 78,000 BDT per year. In the baseline period, 5% of hog fuel was be received by barge and 95% of hog fuel was received by truck from offsite. During the baseline period, hog fuel was transported from the barge unloading system to the hog fuel pile via an existing chip reclaim system. A moisture content of 50% is used to convert BDT of hog fuel to as-transported (i.e., wet) hog fuel.

[d] The post-project hog fuel throughput is equal to 197,000 BDT per year. Following the project, approximately 10-20% of hog fuel will be received by barge and the remainder will be received from offsite by truck. Post project, hog fuel will be transported from the barge unloading system to the hog fuel pile via truck. As more emissions are generated from unpaved travel from the barge than from paved travel from off-site, it is assumed that 20% of hog fuel will be received by barge and 80% of hog fuel will be received from offsite by truck for haul road emission calculation purposes. A moisture content of 50% is used to convert BDT of hog fuel to as-transported (i.e., wet) hog fuel.

[e] The vehicle load weight is calculated as the loaded vehicle weight minus the empty vehicle weight for hog fuel and post-project fly ash vehicles.

[f] Before and after the project, hog fuel is transported by truck. After the project, fly ash will be transported by truck. The hog fuel and post-project fly ash vehicle weights provided by the Harris Group. The loaded and empty weights of a chip truck is assumed.

[g] Fly ash was transported during the baseline period, however, baseline fly ash throughput is not used in the haul road emission calculations.

[h] In the baseline period, fly ash is transported to the landfill by front end loader. Load weight is calculated as the average annual throughput of dry fly ash transported from 2005 to 2009 divided by the annual average number of trips from 2005 to 2009. As the water included with each load is not accounted for in this calculation, the baseline load weight is conservatively underestimated.

[i] In the baseline period, fly ash is transported using a front-end loader with a typical load bucket volume of 7 cubic yards. The operating weight of a Caterpillar 980H Wheel Loader is used as the vehicle weight. This front end loader, with a bucket capacity of 5.0 to 8.0 cubic yards, has an operating vehicle weight of 67,294 pounds.

[j] The loaded vehicle weight is equal to the load weight plus the empty vehicle weight for the baseline fly ash vehicle.

[k] Following the project, fly ash will be produced at a rate of 3,400 dry lb/hr. For calculation purposes, it is assumed that the fly ash will contain 50% moisture when transported to the landfill.

Table B-38. Haul Road Emission Factors

Vehicle Type	Emission Factors - Empty Vehicles (lb/VMT)			Emission Factors - Loaded Vehicles (lb/VMT) [a]		
	PM	**PM_{10}**	**$PM_{2.5}$**	**PM**	**PM_{10}**	**$PM_{2.5}$**
Hog Fuel - Barge Unloading	3.866	1.102	0.110	6.793	1.936	0.194
Hog Fuel - Trucked from Offsite	0.077	0.014	0.002	0.212	0.040	0.006
Fly Ash - Baseline Period	5.380	1.530	0.153	5.706	1.622	0.163
Fly Ash - Post Project	3.108	0.884	0.089	5.476	1.557	0.156

[a] Emission factors are calculated based on the equation in *Paved Road Modifications to AP-42 Background Documentation,* Section 3.2, prepared by the Midwest Research Institute, dated July 18, 2008. Per an email from Lisa Alam, Nebraska Department of Environmental Quality, to Arron Heinerikson, Trinity, the second coefficient should be 0.68 as opposed to the 0.8 listed in the background documentation. The precipitation correction term provided in the existing AP-42 Section 13.2.1.3 is used in the calculations. The following values are used to calculate the emission factors:

Silt Loading for Paved Roads (g/m^2):	0.4	Based on AWMA Air Pollution Engineering Manual second edition, page 126, default silt loading for normal roads with less than 5,000 vehicles per day.
Silt Content for Unpaved Roads (%):	8.4	Per AP-42, Table 13.2.2-1, the mean silt content for "Lumber Sawmills " is used
Number of "wet" days/year	150	Wet days are defined as days with at least 0.01 in of precipitation. Number of wet days for the Portage Bay weather station in Seattle, WA (the nearest major weather observing station), as provided by National Oceanic and Atmospheric Administration (NOAA)'s Comparative Climatic Data Publication through 2009.

Table B-39. Haul Road Emission Factor Constants

Constant	Units	PM	PM_{10}	$PM_{2.5}$
Paved Road Constants				
Particle Size Multiplier (k) [a]	lb/VMT	0.120	0.023	0.0034
Brake & Tire Wear Constant (C) [b]	lb/VMT	0.00047	0.00047	0.00036
Unpaved Road Constants				
Particle Size Multiplier (k) [c]	lb/VMT	4.9	1.5	0.15
Constant "a" [c]	N/A	0.7	0.9	0.9
Constant "b" [c]	N/A	0.45	0.45	0.45

[a] Per *Paved Road Modifications to AP-42 Background Documentation* , Section 3.2, prepared by the Midwest Research Institute, dated July 18, 2008. PM_{30} is used as a surrogate for PM.

[b] Per AP-42 Table 13.2.1-2. The brake and tire wear constants are not affected by the *Paved Road Modifications to AP-42 Background Documentation* , prepared by the Midwest Research Institute, dated July 18, 2008.

[c] Per AP-42, Table 13.2.2-2, PM_{30} is used as a surrogate for PM.

Table B-40. Baseline Haul Road Emissions

Vehicle Type	Baseline Scenario			Emission Rate (tpy) [a]		
	Trips (trips/year)	One-Way Distance [b] (mi/one-way trip)	VMT (mi/year)	PM	PM_{10}	$PM_{2.5}$
Hog Fuel - Barge Unloading [c]	0	0.27	0	0.00	0.00	0.00
Hog Fuel - Trucked from Offsite [d]	5,928	0.30	3,593	0.26	0.05	0.01
Fly Ash [e]	1,520	0.98	1,496	4.15	1.18	0.12
Total				4.41	1.23	0.12

[a] Emissions are calculated using the emission factors calculated in Table B-38. It is assumed that the vehicle travels one way loaded and one way unloaded. Therefore, emissions from a single vehicle trip are equal to the sum of the emissions from the loaded vehicle one-way trip and the unloaded vehicle one-way trip.

[b] One-way distances for hog fuel truck routes are provided by the Harris Group. The one way distance for the fly ash route is provided by PTPC.

[c] During the baseline period, hog fuel was transported from the barge unloading system to the hog fuel pile via the existing chip reclaim system. The hog fuel barge unloading truck route is a new emission unit; therefore, baseline actual emissions for the unit are equal to zero.

[d] The number of trips per year for hog fuel trucks is calculated by dividing the future potential material throughput, as listed in Table B-37 by the weight per load, as listed in Table B-37.

[e] The number of trips per year for fly ash front-end loaders is based on annual solid waste reports.

Table B-41. Future Potential Haul Road Emissions

Vehicle Type	Post-Project Scenario			Emission Rate (tpy) [a]		
	Trips [b] (trips/year)	One-Way Distance [c] (mi/one-way trip)	VMT (mi/year)	PM	PM_{10}	$PM_{2.5}$
Hog Fuel - Barge Unloading	3,152	0.27	1,672	4.45	1.27	0.13
Hog Fuel - Trucked from Offsite	12,608	0.30	7,641	0.55	0.10	0.01
Fly Ash	894	0.98	880	1.89	0.54	0.05
Total				6.89	1.91	0.20

[a] Emissions are calculated using the emission factors calculated in Table B-38. It is assumed that the vehicle travels one way loaded and one way unloaded. Therefore, emissions from a single vehicle trip are equal to the sum of the emissions from the loaded vehicle one-way trip and the unloaded vehicle one-way trip.

[b] The number of trips for each vehicle per year is calculated by dividing the future potential material throughput, as listed in Table B-37 by the weight per load, as listed in Table B-37.

[c] One-way distances for hog fuel truck routes are provided by the Harris Group. The one way distance for the fly ash route is provided by PTPC.

Table B-42. Baseline Storage Pile Emissions

Storage Pile	Footprint Area [a] (acre)	Emission Factors (lb/day/acre) [b]			Emission Rates (tpy)		
		PM	PM_{10} [c]	$PM_{2.5}$ [c]	PM	PM_{10}	$PM_{2.5}$
Hog Fuel Storage Pile	1.03	4.23	2.11	2.11	0.80	0.40	0.40
Urban Wood Storage Pile	0.00	4.23	2.11	2.11	0.00	0.00	0.00
Forest Waste Storage Pile	0.00	4.23	2.11	2.11	0.00	0.00	0.00
Total					0.80	0.40	0.40

[a] The hog fuel storage pile is an existing pile, but will increase in size as a result of the project. The urban wood storage pile and the forest waste piles are new storage piles that will be created as part of the project. Baseline storage pile sizes provided by Harris Group.

[b] Storage pile emissions are calculated using the methodology outlined the EPA document *Control of Open Fugitive Dust Sources* , September 1988, EPA-450/3-88-008, Section 4.1.3 (Wind Emissions from Continuously Active Piles).

Silt Content (%):	8.4	Per AP-42, Table 13.2.2-1, the mean silt content for "Lumber Sawmills " is used.
Number of “wet” days/year	150	Wet days are defined as days with at least 0.01 in of precipitation. Number of wet days for the Portage Bay weather station in Seattle, WA (the nearest major weather observing station), as provided by National Oceanic and Atmospheric Administration (NOAA)'s Comparative Climatic Data Publication through 2009.
% of time the unobstructed wind speed exceeds 12 mph at the mean pile height (%):	7.28	Calculated based on 2009 meteorological data from the Port Angeles, WA meteorological station, the nearest station to the Port Townsend facility.

[c] PM_{10} is assumed to be 50% of PM per EPA-450/3-88-008, page 4-17. $PM_{2.5}$ is assumed equal to PM_{10}.

Table B-43. Future Potential Storage Pile Emissions

Storage Pile	Footprint Area [a] (acre)	Emission Factors (lb/day/acre) [b]			Emission Rates (tpy)		
		PM	PM_{10} [c]	$PM_{2.5}$ [c]	PM	PM_{10}	$PM_{2.5}$
Hog Fuel Storage Pile	1.10	4.23	2.11	2.11	0.85	0.43	0.43
Urban Wood Storage Pile	0.52	4.23	2.11	2.11	0.40	0.20	0.20
Forest Waste Storage Pile	0.52	4.23	2.11	2.11	0.40	0.20	0.20
Total					1.65	0.82	0.82

[a] Post project storage pile sizes provided by Harris Group.

[b] Storage pile emissions are calculated using the methodology outlined the EPA document *Control of Open Fugitive Dust Sources* , September 1988, EPA-450/3-88-008, Section 4.1.3 (Wind Emissions from Continuously Active Piles).

Silt Content (%):	8.4	Per AP-42, Table 13.2.2-1, the mean silt content for "Lumber Sawmills " is used.
Number of “wet” days/year	150	Wet days are defined as days with at least 0.01 in of precipitation. Number of wet days for the Portage Bay weather station in Seattle, WA (the nearest major weather observing station), as provided by National Oceanic and Atmospheric Administration (NOAA)'s Comparative Climatic
% of time the unobstructed wind speed exceeds 12 mph at the mean pile height	7.28	Calculated based on 2009 meteorological data from the Port Angeles, WA meteorological station.

[c] PM_{10} is assumed to be 50% of PM per EPA-450/3-88-008, page 4-17. $PM_{2.5}$ is assumed equal to PM_{10}.

APPENDIX C

TOXIC AIR POLLUTANT EMISSIONS CALCULATIONS

AIR QUALITY MODELING SUPPORTING INFORMATION

Table C-1. TAP Emission Calculations for Power Boiler 10

TAP		CAS Number	Emission Factors [a, b] (lb/MMBtu)	TAP Emission Increase [c] (lb/hr)
1,1,1-Trichloroethane		71-55-6	5.78E-05	5.61E-03
1,2-Dichloroethane		107-06-2	2.92E-05	2.83E-03
1,2-Dibromoethane		106-93-4	5.48E-05	5.32E-03
1,2-Dichloropropane		78-87-5	3.33E-05	3.23E-03
2,4-Dinitrotoluene		121-14-2	9.42E-07	9.14E-05
2,3,7,8-Tetrachlorodibenzo-p-dioxin	d	1746-01-6	6.89E-12	6.69E-10
2,3,7,8-Tetrachlorodibenzofuran	d	51207-31-9	9.47E-11	9.19E-09
1,2,3,7,8-Pentachlorodibenzo-p-dioxin	d	40321-76-4	1.29E-11	1.25E-09
1,2,3,7,8-Pentachlorodibenzofuran	d	57117-41-6	2.28E-11	2.21E-09
2,3,4,7,8-Pentachlorodibenzofuran	d	57117-31-4	3.12E-11	3.03E-09
1,2,3,4,7,8-Hexachlorodibenzo-p-dioxin	d	39227-28-6	2.49E-11	2.42E-09
1,2,3,6,7,8 Hexachlorodibenzo-p-dioxin	d	57653-85-7	4.89E-11	4.74E-09
1,2,3,7,8,9-Hexachlorodibenzo-p-dioxin	d	19408-74-3	5.94E-11	5.76E-09
1,2,3,4,7,8-Hexachlorodibenzofuran	d	70648-26-9	4.81E-11	4.67E-09
1,2,3,6,7,8 Hexachlorodibenzofuran	d	57117-44-9	2.44E-11	2.37E-09
1,2,3,7,8,9-Hexachlorodibenzofuran	d	72918-21-9	1.00E-11	9.73E-10
2,3,4,6,7,8-Hexachlorodibenzofuran	d	60851-34-5	3.03E-11	2.94E-09
1,2,3,4,6,7,8-Heptachlorodibenzo-p-dioxin	d	35822-46-9	5.05E-10	4.90E-08
1,2,3,4,6,7,8-Heptachlorodibenzofuran	d	67562-39-4	1.41E-10	1.37E-08
1,2,3,4,7,8,9-Heptachlorodibenzofuran	d	55673-89-7	4.97E-11	4.83E-09
1,2,3,4,6,7,8,9-Octachlorodibenzo-p-Dioxin	d	3268-87-9	5.53E-10	5.37E-08
1,2,3,4,6,7,8,9-Octachlorodibenzofuran	d	39001-02-0	4.07E-10	3.96E-08
2,4,6-Trichlorophenol		88-06-2	2.73E-07	2.65E-05
Acetaldehyde		75-07-0	2.73E-04	2.65E-02
Acrolein		107-02-8	1.51E-04	1.47E-02
Ammonia	g	7664-41-7	25 ppmdv	7.16E+00
Benzene		71-43-2	2.35E-04	2.28E-02
Benz(a)anthracene	e	56-55-3	6.50E-08	6.31E-06
Benzo(a)pyrene	e	50-32-8	2.60E-06	2.52E-04
Benzo(b)fluoranthene	e	205-99-2	1.00E-07	9.71E-06
Benzo(j)fluoranthene	e	205-82-3	1.60E-07	1.55E-05
Benzo(k)fluoranthene	e	207-08-9	3.60E-08	3.49E-06
Carbon Disulfide		75-15-0	1.25E-04	1.21E-02
Carbon Monoxide	h	630-08-0	3.50E-01	3.40E+01
Carbon Tetrachloride		56-23-5	1.26E-05	1.22E-03
Chlorine	f	7782-50-5	7.93E-04	7.70E-02
Chlorobenzene		108-90-7	1.66E-05	1.61E-03
Chloroform		67-66-3	3.52E-05	3.42E-03
Chrysene	f	218-01-9	3.80E-08	3.69E-06
Cumene		98-82-8	1.77E-05	1.72E-03
Dichloromethane		75-09-2	6.22E-04	6.04E-02
Dibenzo(a,h)anthracene	e	53-70-3	9.10E-09	8.83E-07
Ethylbenzene		100-41-4	1.76E-05	1.71E-03
Formaldehyde		50-00-0	8.83E-04	8.57E-02
Hexachlorobenzene		118-74-1	1.03E-06	1.00E-04
n-Hexane		110-54-3	2.88E-04	2.80E-02
Hydrogen Chloride		7647-01-0	1.61E-03	1.56E-01
Indeno(1,2,3-cd)pyrene	e	193-39-5	8.70E-08	8.45E-06
Isopropyl Alcohol		67-63-0	3.64E-03	3.53E-01
Methyl Alcohol		67-56-1	7.99E-04	7.76E-02
Methyl Bromide		74-83-9	1.52E-05	1.48E-03
Methyl Chloride		74-87-3	4.03E-05	3.91E-03
Methyl Ethyl Ketone		78-93-3	8.65E-06	8.40E-04
Methyl Isobutyl Ketone		108-10-1	4.45E-04	4.32E-02

Table C-1. TAP Emission Calculations for Power Boiler 10

TAP	CAS Number	Emission Factors [a, b] (lb/MMBtu)	TAP Emission Increase [c] (lb/hr)
Naphthalene	91-20-3	9.01E-05	8.75E-03
Pentachlorophenol	87-86-5	2.29E-07	2.22E-05
Perchloroethylene	127-18-4	3.82E-05	3.71E-03
Phenol	108-95-2	9.46E-05	9.18E-03
Styrene	100-42-5	6.30E-04	6.12E-02
Toluene	108-88-3	2.43E-05	2.36E-03
Trichloroethylene	79-01-6	1.94E-05	1.88E-03
Vinyl Chloride	75-01-4	1.84E-05	1.79E-03
o-Xylene	95-47-6	1.13E-05	1.10E-03
m-Xylene [i]	108-38-3	3.54E-06	3.44E-04
p-Xylene [i]	106-42-3	3.54E-06	3.44E-04

[a] Emission of nitrogen dioxide, sulfur dioxide, and trace metals are expected to decrease as a result of this project. Nitrogen dioxide emissions will decrease due to the installation of SNCR, sulfur dioxide emissions will decrease due the Power Boiler 10 firing less oil and increasing the effectiveness of the scrubber caustic solution; and trace metals are expected to decrease as a result of the proposed dry ESP. As such, these TAPs are not included in the emission calculations.

[b] Unless otherwise indicated, the maximum of the median and mean emission factors listed in Table 7.1 ("Summary of 'Air Toxic' Emissions from Wood-Fired Boilers") of the NCASI Technical Bulletin (TB) No. 973, dated February 2010, were conservatively selected for TAPs emission calculation purposes. As the unit is increasing throughput of solid fuel only, emission factors for wood-fired boilers are used to quantify the increase in TAPs emissions associated with the project. The median emission factor is used for benzene and formaldehyde emissions. All source testing for bromodichloromethane and 1,1,2-trichloroethane resulted in non-detects; as such, emission factors for these pollutants are not used.

[c] Emissions from the Power Boiler 10 are calculated by taking the difference between the maximum hourly heat input once the project is completed (414 MMBtu/hr) and the achievable hourly heat input attained pre-project (317 MMBtu/hr), and multiplying the difference by the respective emission factor for each TAP. The achievable hourly heat input attained pre-project is determined by analyzing steam production rates (4 hour averages) during the time period of January 25, 2009 - January 25, 2010. A steam production rate of 206,000 lbs/hr steam or higher was achieved twenty percent of the time during the period analyzed. It is assumed that the boiler is 65 percent efficient when firing wood and that is takes 1,000 Btu to convert 1 pound of steam.

[d] The maximum of the median and mean emission factors listed in Table 9.1 ("PCDD/F Emissions for Fifteen Bark/Wood Residue-Fired FPI Boilers with and without WWTP Residuals") of the NCASI TB No. 973 were conservatively selected for dioxin and furan TAPs emission calculation purposes. Emission factors are provided in units of µg/oven dry ton wood. To convert to lb/MMBtu, a heating value of 8,800 Btu/lb wood is used.

Wood heat input: 8,800 Btu/lb

[e] The emission factor for boilers firing wood fuel listed in Table 8.1 ("Summary of Polycyclic Organic Matter Emissions (PACs) from Kraft Recovery Sources and Boilers") of the NCASI TB No. 973 were selected for TAPs emission calculation purposes.

[f] Emission factors listed in AP-42, Table 1.6-3 dated September 2003.

[g] Ammonia emission factor estimated by the Harris Group. NH_3 emissions are calculated using the following equation: flow rate (sdcfm) * 60 (min/hr) * 17 (lbs NH_3/lb-mol NH_3) * concentration (ppmv) / 359.1 (ft3/lb-mol). The flow rate is assumed to be 100,836 dscfm.

[h] The Power Boiler 10 is expected to meet the site-specific carbon monoxide emission factor once the project is completed.

[i] In NCASI TB No. 937, a combined emission factor for xylene-m,p is provided. This combined emission factor is used as the individual emission factor for m-xylene and p-xylene.

Table C-2. TAPs Screening

TAP [a]	CAS Number	Emission Increase (lb/hr)	Daily Emission Rate (lb/day)	Annual Emission Rate (lb/year)	ASIL [a] (ug/m^3)	Averaging Period	SQER [a] (lb/averaging period)	De Minimis [a] (lb/average period)	Is Modeling Required? [b]
1,1,1-Trichloroethane	71-55-6	5.6E-03	1.3E-01	4.9E+01	1.00E+03	24-hr	1.31E+02	6.57E+00	de minimis
1,2-Dichloroethane	107-06-2	2.8E-03	6.8E-02	2.5E+01	3.85E-02	year	7.39E+00	3.69E-01	Yes
1,2-Dibromoethane	106-93-4	5.3E-03	1.3E-01	4.7E+01	1.41E-02	year	2.71E+00	1.35E-01	Yes
1,2-Dichloropropane	78-87-5	3.2E-03	7.8E-02	2.8E+01	1.00E-01	year	1.92E+01	9.59E-01	Yes
2,4-Dinitrotoluene	121-14-2	9.1E-05	2.2E-03	8.0E-01	1.12E-02	year	2.15E+00	1.07E-01	No
2,3,7,8-Tetrachlorodibenzo-p-dioxin	1746-01-6	6.7E-10	1.6E-08	5.9E-06	2.63E-08	year	5.05E-06	2.52E-07	Yes
2,3,7,8-Tetrachlorodibenzofuran	51207-31-9	9.2E-09	2.2E-07	8.1E-05	2.63E-07	year	5.05E-05	2.52E-06	Yes
1,2,3,7,8-Pentachlorodibenzo-p-dioxin	40321-76-4	1.3E-09	3.0E-08	1.1E-05	2.63E-08	year	5.05E-06	2.52E-07	Yes
1,2,3,7,8-Pentachlorodibenzofuran	57117-41-6	2.2E-09	5.3E-08	1.9E-05	5.26E-07	year	1.01E-04	5.05E-06	No
2,3,4,7,8-Pentachlorodibenzofuran	57117-31-4	3.0E-09	7.3E-08	2.7E-05	5.26E-08	year	1.01E-05	5.05E-07	Yes
1,2,3,4,7,8-Hexachlorodibenzo-p-dioxin	39227-28-6	2.4E-09	5.8E-08	2.1E-05	2.63E-07	year	5.05E-05	2.52E-06	No
1,2,3,6,7,8 Hexachlorodibenzo-p-dioxin	57653-85-7	4.7E-09	1.1E-07	4.2E-05	2.63E-07	year	5.05E-05	2.52E-06	No
1,2,3,7,8,9-Hexachlorodibenzo-p-dioxin	19408-74-3	5.8E-09	1.4E-07	5.0E-05	2.63E-07	year	5.05E-05	2.52E-06	No
1,2,3,4,7,8-Hexachlorodibenzofuran	70648-26-9	4.7E-09	1.1E-07	4.1E-05	2.63E-07	year	5.05E-05	2.52E-06	No
1,2,3,6,7,8 Hexachlorodibenzofuran	57117-44-9	2.4E-09	5.7E-08	2.1E-05	2.63E-07	year	5.05E-05	2.52E-06	No
1,2,3,7,8,9-Hexachlorodibenzofuran	72918-21-9	9.7E-10	2.3E-08	8.5E-06	2.63E-07	year	5.05E-05	2.52E-06	No
2,3,4,6,7,8-Hexachlorodibenzofuran	60851-34-5	2.9E-09	7.1E-08	2.6E-05	2.63E-07	year	5.05E-05	2.52E-06	No
1,2,3,4,6,7,8-Heptachlorodibenzo-p-dioxin	35822-46-9	4.9E-08	1.2E-06	4.3E-04	2.63E-06	year	5.05E-04	2.52E-05	No
1,2,3,4,6,7,8-Heptachlorodibenzofuran	67562-39-4	1.4E-08	3.3E-07	1.2E-04	2.63E-06	year	5.05E-04	2.52E-05	No
1,2,3,4,7,8,9-Heptachlorodibenzofuran	55673-89-7	4.8E-09	1.2E-07	4.2E-05	2.63E-06	year	5.05E-04	2.52E-05	No
1,2,3,4,6,7,8,9-Octachlorodibenzo-p-Dioxin	3268-87-9	5.4E-08	1.3E-06	4.7E-04	2.63E-04	year	5.05E-02	2.52E-03	de minimis
1,2,3,4,6,7,8,9-Octachlorodibenzofuran	39001-02-0	4.0E-08	9.5E-07	3.5E-04	2.63E-04	year	5.05E-02	2.52E-03	de minimis
2,4,6-Trichlorophenol	88-06-2	2.7E-05	6.4E-04	2.3E-01	5.00E-02	year	9.59E+00	4.80E-01	de minimis
Acetaldehyde	75-07-0	2.7E-02	6.4E-01	2.3E+02	3.70E-01	year	7.10E+01	3.55E+00	Yes
Acrolein	107-02-8	1.5E-02	3.5E-01	1.3E+02	6.00E-02	24-hr	7.89E-03	3.94E-04	Yes
Ammonia	7664-41-7	7.2E+00	1.7E+02	6.3E+04	7.08E+01	24-hr	9.31E+00	4.65E-01	Yes
Benzene	71-43-2	2.3E-02	5.5E-01	2.0E+02	3.45E-02	year	6.62E+00	3.31E-01	Yes
Benz(a)anthracene	56-55-3	6.3E-06	1.5E-04	5.5E-02	9.09E-03	year	1.74E+00	8.72E-02	de minimis
Benzo(a)pyrene	50-32-8	2.5E-04	6.1E-03	2.2E+00	9.09E-04	year	1.74E-01	8.72E-03	Yes
Benzo(b)fluoranthene	205-99-2	9.7E-06	2.3E-04	8.5E-02	9.09E-03	year	1.74E+00	8.72E-02	de minimis
Benzo(j)fluoranthene	205-82-3	1.6E-05	3.7E-04	1.4E-01	9.09E-03	year	1.74E+00	8.72E-02	No
Benzo(k)fluoranthene	207-08-9	3.5E-06	8.4E-05	3.1E-02	9.09E-03	year	1.74E+00	8.72E-02	de minimis
Carbon Disulfide	75-15-0	1.2E-02	2.9E-01	1.1E+02	8.00E+02	24-hr	1.05E+02	5.26E+00	de minimis
Carbon Monoxide	630-08-0	3.4E+01	8.2E+02	3.0E+05	2.30E+04	1-hr	5.04E+01	1.14E+00	No
Carbon Tetrachloride	56-23-5	1.2E-03	2.9E-02	1.1E+01	2.38E-02	year	4.57E+00	2.28E-01	Yes
Chlorine	7782-50-5	7.7E-02	1.8E+00	6.7E+02	2.00E-01	24-hr	2.60E-02	1.31E-03	Yes
Chlorobenzene	108-90-7	1.6E-03	3.9E-02	1.4E+01	1.00E+03	24-hr	1.31E+02	6.57E+00	de minimis
Chloroform	67-66-3	3.4E-03	8.2E-02	3.0E+01	4.35E-02	year	8.35E+00	4.17E-01	Yes
Chrysene	218-01-9	3.7E-06	8.9E-05	3.2E-02	9.09E-02	year	1.74E+01	8.72E-01	de minimis
Cumene	98-82-8	1.7E-03	4.1E-02	1.5E+01	4.00E+02	24-hr	5.26E+01	2.63E+00	de minimis
Dichloromethane	75-09-2	6.0E-02	1.4E+00	5.3E+02	1.00E+00	year	1.92E+02	9.59E+00	Yes
Dibenzo(a,h)anthracene	53-70-3	8.8E-07	2.1E-05	7.7E-03	8.33E-04	year	1.60E-01	7.99E-03	de minimis
Ethylbenzene	100-41-4	1.7E-03	4.1E-02	1.5E+01	4.00E-01	year	7.68E+01	3.84E+00	No
Formaldehyde	50-00-0	8.6E-02	2.1E+00	7.5E+02	1.67E-01	year	3.20E+01	1.60E+00	Yes
Hexachlorobenzene	118-74-1	1.0E-04	2.4E-03	8.8E-01	1.96E-03	year	3.76E-01	1.88E-02	Yes
n-Hexane	110-54-3	2.8E-02	6.7E-01	2.4E+02	7.00E+02	24-hr	9.20E+01	4.60E+00	de minimis
Hydrogen Chloride	7647-01-0	1.6E-01	3.8E+00	1.4E+03	9.00E+00	24-hr	1.18E+00	5.91E-02	Yes
Indeno(1,2,3-cd)pyrene	193-39-5	8.4E-06	2.0E-04	7.4E-02	9.09E-03	year	1.74E+00	8.72E-02	de minimis
Isopropyl Alcohol	67-63-0	3.5E-01	8.5E+00	3.1E+03	3.20E+03	1-hr	7.01E+00	3.50E-01	No
Methyl Alcohol	67-56-1	7.8E-02	1.9E+00	6.8E+02	4.00E+03	24-hr	5.26E+02	2.63E+01	de minimis
Methyl Bromide	74-83-9	1.5E-03	3.5E-02	1.3E+01	5.00E+00	24-hr	6.57E-01	6.29E-02	de minimis
Methyl Chloride	74-87-3	3.9E-03	9.4E-02	3.4E+01	9.00E+01	24-hr	1.18E+01	5.91E-01	de minimis
Methyl Ethyl Ketone	78-93-3	8.4E-04	2.0E-02	7.4E+00	5.00E+03	24-hr	6.57E+02	3.29E+01	de minimis
Methyl Isobutyl Ketone	108-10-1	4.3E-02	1.0E+00	3.8E+02	3.00E+03	24-hr	3.94E+02	1.97E+01	de minimis
Naphthalene	91-20-3	8.7E-03	2.1E-01	7.7E+01	2.94E-02	year	5.64E+00	2.82E-01	Yes
Pentachlorophenol	87-86-5	2.2E-05	5.3E-04	1.9E-01	2.17E-01	year	4.16E+01	2.08E+00	de minimis
Perchloroethylene	127-18-4	3.7E-03	8.9E-02	3.2E+01	1.69E-01	year	3.24E+01	1.62E+00	Yes
Phenol	108-95-2	9.2E-03	2.2E-01	8.0E+01	2.00E+02	24-hr	2.63E+01	1.31E+00	de minimis
Styrene	100-42-5	6.1E-02	1.5E+00	5.4E+02	9.00E+02	24-hr	1.18E+02	5.91E+00	de minimis
Toluene	108-88-3	2.4E-03	5.7E-02	2.1E+01	5.00E+03	24-hr	6.57E+02	3.29E+01	de minimis
Trichloroethylene	79-01-6	1.9E-03	4.5E-02	1.6E+01	5.00E-01	year	9.59E+01	4.80E+00	No
Vinyl Chloride	75-01-4	1.8E-03	4.3E-02	1.6E+01	1.28E-02	year	2.46E+00	1.23E-01	Yes
o-Xylene	95-47-6	1.1E-03	2.6E-02	9.6E+00	2.21E+02	24-hr	2.90E+01	1.45E+00	de minimis
m-Xylene	108-38-3	3.4E-04	8.2E-03	3.0E+00	2.21E+02	24-hr	2.90E+01	1.45E+00	de minimis
p-Xylene	106-42-3	3.4E-04	8.2E-03	3.0E+00	2.21E+02	24-hr	2.90E+01	1.45E+00	de minimis

[a] TAPs and their corresponding acceptable source impact level (ASIL), averaging period, small quantity emission rate (SQER), and de minimis emission rate are taken from Washington's revised TAPs rule (WAC 173-460), which became effective on June 20, 2009.
[b] Modeling is required if the project-related emissions increase of the TAP is greater than the SQER for the TAP. If the emissions increase is less than the de minimis threshold, a notice of construction application for that particular pollutant is not required per WAC 173-460-040(1).

Table C-3. Toxic Air Pollutant Screening - Model Input and Output

Emission Point [a]	Stack Height (ft)	Exit Temperature (F)	Inside Diameter (ft)	Flow Rate (dscfm)	Distance to Property Line (m)	Building Height [b] (m)	Minimum Horizontal Dimension [b] (m)	Maximum Horizontal Dimension [b] (m)	Modeled Output [c] (ug/m^3)
Power Boiler 10	174	142	7.0	100,836	182.9	48.77	22.46	54.21	**6.35E+00**

[a] The emission rate of 1 lb/hr was used as an input to the Screen3 model to determine the modeled concentration.

[b] The building height, minimum horizontal dimension, and maximum horizontal dimension were determined in a previous modeling analysis conducted for the PTPC Mill.

[c] SCREEN3 Model output represents the maximum concentration outside of property boundary.

Table C-4. Toxic Air Pollutant Screening - Modeling Results

Pollutant	Is Modeling Required?	Hourly Maximum (ug/m^3)	Averaging Period	Multiplying Factor[a]	Maximum (ug/m^3)	ASIL (ug/m^3)	Pass ASIL? (Yes/No)
1,2-Dichloroethane	Yes	1.80E-02	year	0.08	1.44E-03	3.85E-02	Yes
1,2-Dibromoethane	Yes	3.38E-02	year	0.08	2.70E-03	1.41E-02	Yes
1,2-Dichloropropane	Yes	2.05E-02	year	0.08	1.64E-03	1.00E-01	Yes
2,3,7,8-Tetrachlorodibenzo-p-dioxin	Yes	4.25E-09	year	0.08	3.40E-10	2.63E-08	Yes
2,3,7,8-Tetrachlorodibenzofuran	Yes	5.84E-08	year	0.08	4.67E-09	2.63E-07	Yes
1,2,3,7,8-Pentachlorodibenzo-p-dioxin	Yes	7.95E-09	year	0.08	6.36E-10	2.63E-08	Yes
2,3,4,7,8-Pentachlorodibenzofuran	Yes	1.92E-08	year	0.08	1.54E-09	5.26E-08	Yes
Acetaldehyde	Yes	1.68E-01	year	0.08	1.35E-02	3.70E-01	Yes
Acrolein	Yes	9.31E-02	24-hr	0.4	3.72E-02	6.00E-02	Yes
Ammonia	Yes	4.55E+01	24-hr	0.4	1.82E+01	7.08E+01	Yes
Benzene	Yes	1.45E-01	year	0.08	1.16E-02	3.45E-02	Yes
Benzo(a)pyrene	Yes	1.60E-03	year	0.08	1.28E-04	9.09E-04	Yes
Carbon Tetrachloride	Yes	7.77E-03	year	0.08	6.21E-04	2.38E-02	Yes
Chlorine	Yes	4.89E-01	24-hr	0.4	1.96E-01	2.00E-01	Yes
Chloroform	Yes	2.17E-02	year	0.08	1.74E-03	4.35E-02	Yes
Dichloromethane	Yes	3.83E-01	year	0.08	3.07E-02	1.00E+00	Yes
Formaldehyde	Yes	5.44E-01	year	0.08	4.35E-02	1.67E-01	Yes
Hexachlorobenzene	Yes	6.35E-04	year	0.08	5.08E-05	1.96E-03	Yes
Hydrogen Chloride	Yes	9.92E-01	24-hr	0.4	3.97E-01	9.00E+00	Yes
Naphthalene	Yes	5.55E-02	year	0.08	4.44E-03	2.94E-02	Yes
Perchloroethylene	Yes	2.35E-02	year	0.08	1.88E-03	1.69E-01	Yes
Vinyl Chloride	Yes	1.13E-02	year	0.08	9.07E-04	1.28E-02	Yes

[a] Per U.S. Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and Standards, Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised. (Research Triangle Park, NC: U.S. EPA EPA-454/R-92-019), p. 15.

04/22/2010

18:42:13

*** SCREEN3 MODEL RUN ***
*** VERSION DATED 96043 ***

```
 PTPC POWER BOILER 10 ** 182.9

 SIMPLE TERRAIN INPUTS:
    SOURCE TYPE            =        POINT
    EMISSION RATE (G/S)    =     0.125998
    STACK HEIGHT (M)       =      53.0352
    STK INSIDE DIAM (M)    =       2.1336
    STK EXIT VELOCITY (M/S)=      15.1263
    STK GAS EXIT TEMP (K)  =     334.2611
    AMBIENT AIR TEMP (K)   =     293.0000
    RECEPTOR HEIGHT (M)    =       0.0000
    URBAN/RURAL OPTION     =        RURAL
    BUILDING HEIGHT (M)    =      48.7700
    MIN HORIZ BLDG DIM (M) =      22.4600
    MAX HORIZ BLDG DIM (M) =      54.2100

 THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
 THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

    STACK EXIT VELOCITY WAS CALCULATED FROM
    VOLUME FLOW RATE =   54.081409     (M**3/S)

 BUOY. FLUX =   20.838 M**4/S**3;  MOM. FLUX =  228.251 M**4/S**2.

 *** FULL METEOROLOGY ***

 **********************************
 *** SCREEN AUTOMATED DISTANCES ***
 **********************************

 *** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING
DISTANCES ***
```

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
1.	0.000	0	0.0	0.0	0.0	0.00	0.00	0.00	NA
100.	0.000	0	0.0	0.0	0.0	0.00	0.00	0.00	NA
200.	5.905	6	2.0	5.0	10000.0	55.33	7.73	29.22	SS
300.	5.121	6	1.5	3.8	10000.0	60.00	11.23	32.00	SS
400.	5.253	6	1.5	3.8	10000.0	60.00	14.64	36.82	SS
500.	5.150	6	1.0	2.5	10000.0	65.13	17.97	37.11	SS
600.	4.427	6	1.0	2.5	10000.0	65.13	21.24	37.40	SS
700.	3.903	6	1.0	2.5	10000.0	65.13	24.46	37.68	

```
SS
    800.   3.505        6     1.0    2.5 10000.0   65.13   27.63   37.97
SS
    900.   3.193        6     1.0    2.5 10000.0   65.13   30.78   38.25
SS
   1000.   2.940        6     1.0    2.5 10000.0   65.13   33.88   38.52
SS

 MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
    147.   6.349        6     2.0    5.0 10000.0   54.31    5.85   26.52
SS

  DWASH=   MEANS NO CALC MADE (CONC = 0.0)
  DWASH=NO MEANS NO BUILDING DOWNWASH USED
  DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
  DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
  DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 *********************************
 *** SCREEN DISCRETE DISTANCES ***
 *********************************

 *** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING
DISTANCES ***

   DIST     CONC             U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
    (M)   (UG/M**3)   STAB  (M/S)  (M/S)    (M)   HT (M)   Y (M)   Z (M)
DWASH
 -------  ----------  ----  -----  -----  ------  ------  ------  ------
-----
    182.   6.058        6     2.0    5.0 10000.0   54.94    7.08   28.28
SS

  DWASH=   MEANS NO CALC MADE (CONC = 0.0)
  DWASH=NO MEANS NO BUILDING DOWNWASH USED
  DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
  DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
  DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 ****************************************
      *** REGULATORY (Default) ***
     PERFORMING CAVITY CALCULATIONS
   WITH ORIGINAL SCREEN CAVITY MODEL
           (BRODE, 1988)
 ****************************************


  *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
   CONC (UG/M**3)     =    27.59        CONC (UG/M**3)     =    23.79
   CRIT WS @10M (M/S) =     1.65        CRIT WS @10M (M/S) =     4.62
   CRIT WS @ HS (M/S) =     2.30        CRIT WS @ HS (M/S) =     6.45
   DILUTION WS (M/S)  =     1.15        DILUTION WS (M/S)  =     3.22
   CAVITY HT (M)      =    91.65        CAVITY HT (M)      =    67.17
   CAVITY LENGTH (M)  =   118.93        CAVITY LENGTH (M)  =    33.10
   ALONGWIND DIM (M)  =    22.46        ALONGWIND DIM (M)  =    54.21

 ****************************************
      END OF CAVITY CALCULATIONS
 ****************************************
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****
*** SUMMARY OF SCREEN MODEL RESULTS ***
****

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)	
SIMPLE TERRAIN	6.349	147.	0.	
BLDG. CAVITY-1	27.59	119.	--	(DIST = CAVITY LENGTH)
BLDG. CAVITY-2	23.79	33.	--	(DIST = CAVITY LENGTH)

****
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
****

APPENDIX D

RBLC SEARCH RESULTS

Table D-1. RBLC Search Results for CO Control Devices Installed on Heaters/Boilers (>250 MMBtu/hr)

Fuel Type	State	Facility Name	Permit Date (issue date)	Equipment Description	Throughput	Unit	Control Description	Case-By-Case Basis	CO Limit	Unit
Clean wood	CT	MONTVILLE POWER LLC	4/6/2010	42 MW Biomass utility boiler	600	MMBtu/hr	Oxidation Catalyst	BACT-PSD	0.1	LBS/MMBTU
	CT	MONTVILLE POWER LLC	4/6/2010	82 Utility boiler	995	MMBtu/hr	Oxidation Catalyst	BACT-PSD	0.036	LBS/MMBTU
biomass	TX	LINDALE RENEWABLE ENERGY	1/8/2010	Wood fired boiler	73	tons per hour	Good combustion practices	BACT-PSD	0.31	LB/MMBTU
	MN	KODA ENERGY	8/23/2007	BIOMASS BOILER 4			GOOD COMBUSTION PRACTICE	BACT-PSD	0.43	LB/MMBTU
WOOD WASTE	WA	SIMPSON TACOMA KRAFT COMPANY, LLC	5/22/2007	UTILITY AND LARGE INDUSTRIAL SIZED BOILERS/FURNACES	595	MMBTU/H	OVERFIRE AIR SYSTEM INSTALLED IN 2006 TO IMPROVE COMBUSTION CONDITIONS.	BACT-PSD	0.35	LB/MMBTU
BIOMASS	ND	NORTHERN SUN	5/1/2006	WOOD/HULL FIRED BOILER			GOOD COMBUSTION PRACTICES	BACT-PSD	0.63	LB/MM BTU
WOOD	OH	SOUTH POINT BIOMASS GENERATION	4/4/2006	WOOD FIRED BOILERS (7)	318	MMBTU/H	OXIDATION CATALYST	BACT-PSD	31.8	LB/H
WOOD/BARK	WA	BOISE WHITE PAPER LLC	2/1/2006	UTILITY-AND LARGE INDUSTRIAL-SIZE BOILERS/FURNACES (>250 MILLION BTU/H)	343	MMBTU/H	OVERFIRE AIR SYSTEM ADDED TO IMPROVE THE BOILER'S COMBUSTION SYSTEM. BOILER HAS AN ESP.	Other Case-by-Case	500	PPMVD
BARK & WASTE WOOD	WA	SKAGIT COUNTY LUMBER MILL	1/25/2006	WOOD-FIRED COGENERATION UNIT	430	mmBtu/H		BACT-PSD	400	LB/H
WOOD WASTE	WA	DARRINGTON ENERGY COGENERATION POWER PLANT	2/11/2005	WOOD WASTE-FIRED BOILER	403	MMBTU/H	GOOD COMBUSTION PRACTICES	BACT-PSD	0.35	LB/MMBTU
BARK	LA	BOGALUSA MILL	11/23/2004	NO. 12 HOGGED FUEL BOILER	787.5	MMBTU/H	EXISTING OVERFIRE AIR SYSTEM AND GOOD COMBUSTION PRACTICES	BACT-PSD	491.45	LB/H
BIOMASS	NH	SCHILLER STATION	10/25/2004	BOILER, WOOD FIRED CFB, UNIT #5	720	MMBTU/h	GOOD COMBUSTION PRACTICES WITH THE FLUIDIZED BED DESIGN	BACT-PSD	0.1	LB/MMBTU
BARK	GA	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	10/13/2004	BOILER, SOLID FUEL	856	MMBTU/H	STAGED COMBUSTION AND GOOD COMBUSTION PRACTICES	BACT-PSD	368	PPM @ 3% O2
BAGASSE	FL	CLEWISTON SUGAR MILL AND REFINERY	11/18/2003	EXTERNAL COMBUSTION, MULTIPLE FUELS	936	MMBTU/H	GOOD COMBUSTION AND OPERATING PRACTICES	Other Case-by-Case	0.38	LB/MMBTU
BARK	LA	DERIDDER PAPER MILL	11/14/2003	WOOD-FIRED BOILER	454.29	MMBTU/H	GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION TECHNIQUES	BACT-PSD	149.92	LB/H
WOOD WASTE	AR	DEL TIN FIBER LLC	2/28/2003	HEAT ENERGY SYSTEM	291	MMBTU/H	GOOD COMBUSTION PRACTICE	BACT-PSD	228.3	LB/H
MANURE	MN	FIBROMINN BIOMASS POWER PLANT	10/23/2002	BOILER, MULTIFUEL	792	mmbtu/h	GOOD COMBUSTION PRACTICES	BACT-PSD	0.24	LB/MMBTU
WASTE WOOD	WA	ABERDEEN DIVISION	10/17/2002	HOG FUEL BOILER	310	MMBTU/H	GOOD COMBUSTION	BACT-PSD	0.35	LB/MMBTU
WOOD WASTE	ME	S.D. WARREN CO. - SKOWHEGAN, ME	11/27/2001	BOILER, #2	1300	MMBTU/H	GOOD BOILER DESIGN AND COMBUSTION PRACTICES.	BACT-PSD	520	LB/H
WOOD	MN	DISTRICT ENERGY ST. PAUL, INC	11/15/2001	BOILER	550	MMBTU/H	GOOD COMBUSTION	BACT-PSD	0.3	LB/MMBTU
WOODWASTE AND PAPERMILL SLUDGE	GA	TRI-GEN BIOPOWER	5/24/2001	BOILER, MULTIFUEL	302.2	MMBTU/H	GOOD DESIGN AND COMBUSTION PRINCIPLES	BACT-PSD	90.7	LB/H
BAGASSE	FL	U.S. SUGAR CLEWISTON MILL AND REFINERY	11/29/2000	BOILER, TRAVELING GRATE	633	MMBTU/H	GOOD COMBUSTION PRACTICES	BACT-PSD	6.5	LB/MMBTU

1. Search Criteria for RBLC: Date range from January 1, 2000 through April 29, 2010; Process Information Included Utility - and Large Industrial-Size Boilers (>250 MMBtu/hr) combusting biomass, includes wood, wood waste, bagasse, and other biomass (11.120). Boilers with fuel types that did not include biomass, hogged fuel, wood, wood chips, and/or bark as fuel type are removed from the search results. RBLC search results are presented exactly as they are entered into the RBLC database.

Table D-2. RBLC Search Results for VOC Control Devices Installed on Heaters/Boilers (>250 MMBtu/hr)

Fuel Type	State	Facility Name	Permit Date (issue date)	Equipment Description	Throughput	Unit	Control Description	Case-By-Case Basis	VOC Limit	Units
Clean wood	CT	MONTVILLE POWER LLC	4/6/2010	42 MW Biomass utility boiler	600	MMBtu/hr	Oxidation Catalyst	BACT-PSD	0.01	LBS/MMBTU
WOOD	OH	SOUTH POINT BIOMASS GENERATION	4/4/2006	WOOD FIRED BOILERS (7)	318	MMBTU/H	GOOD COMBUSTION PRACTICES AND USE OF OXIDATION CATALYST	BACT-PSD	4.06	LB/H
BARK & WASTE WOOD	WA	SKAGIT COUNTY LUMBER MILL	1/25/2006	WOOD-FIRED COGENERATION UNIT	430	mmBtu/H		BACT-PSD	0.019	LB/MMBTU
	WA	SKAGIT COUNTY LUMBER MILL	1/25/2006	7. DRY KILNS	300	MM BOARD F/YR	COMPUTERIZED STEAM MANAGEMENT SYSTEM	BACT-PSD	54	T/YR
WOOD CHIPS	AR	POTLATCH CORPORATION - OZAN UNIT	7/26/2005	WOOD FIRED BOILER	110000	LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD	0.034	LB/MMBTU
STEAM HEATED	AR	POTLATCH CORPORATION - OZAN UNIT	7/26/2005	KILNS 1-4	265	MMBF ANNUALLY	PROPER OPERATION		3.5	LB/MMBF
WOOD CHIPS	AR	POTLATCH CORPORATION - OZAN UNIT	7/26/2005	WOOD FIRED BOILER	110000	LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD	0.034	LB/MMBTU
STEAM HEATED	AR	POTLATCH CORPORATION - OZAN UNIT	7/26/2005	KILNS 1-4	265	MMBF ANNUALLY	PROPER OPERATION		3.5	LB/MMBF
BIOMASS	NH	SCHILLER STATION	10/25/2004	BOILER, WOOD FIRED CFB, UNIT #5	720	MMBTU/h	GOOD COMBUSTION PRACTICES	N/A	0.005	LB/MMBTU
BARK	GA	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	10/13/2004	BOILER, SOLID FUEL	856	MMBTU/H	STAGED COMBUSTION AND GOOD COMBUSTION PRACTICES	BACT-PSD	0.05	LB/MMBTU
BAGASSE	FL	CLEWISTON SUGAR MILL AND REFINERY	11/18/2003	EXTERNAL COMBUSTION, MULTIPLE FUELS	936	MMBTU/H	GOOD COMBUSTION AND OPERATING PRACTICES	BACT-PSD	0.05	LB/MMBTU
BARK	LA	DERIDDER PAPER MILL	11/14/2003	WOOD-FIRED BOILER	454.29	MMBTU/H	GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION TECHNIQUES	BACT-PSD	43.49	LB/H
WOOD WASTE	AR	DEL TIN FIBER LLC	2/28/2003	HEAT ENERGY SYSTEM	291	MMBTU/H	CLOSED LOOP SYSTEM - HOT AIR SUPPLIED TO THE DRYERS RETURNS TO THE SYSTEM AS COMBUSTION AIR AND IS NOT RELEASED TO THE ATMOSPHERE UNTIL AFTER THE VOCS ARE DESTROYED AND THE PARTICULATE	BACT-PSD	21.2	LB/H
WOOD WASTE	ME	S.D. WARREN CO. - SKOWHEGAN, ME	11/27/2001	BOILER, #2	1300	MMBTU/H	GOOD BOILER DESIGN AND COMBUSTION PRACTICES. BACT WAS PERFORMED EVEN THOUGH SIGNIFICANCE LEVELS WERE NOT EXCEEDED.	BACT-PSD	9.1	LB/H
BAGASSE	FL	U.S. SUGAR CLEWISTON MILL AND REFINERY	11/29/2000	BOILER, TRAVELING GRATE	633	MMBTU/H	GOOD COMBUSTION PRACTICES	BACT-PSD	0.5	LB/MMBTU

1. Search Criteria for RBLC: Date range from January 1, 2000 through April 29, 2010; Process Information Included Utility - and Large Industrial-Size Boilers (>250 MMBtu/hr) combusting biomass, includes wood, wood waste, bagasse, and other biomass (11.120). Boilers with fuel types that did not include biomass, hogged fuel, wood, wood chips, and/or bark as fuel type are removed from the search results. RBLC search results are presented exactly as they are entered into the RBLC database.

Table D-3. RBLC Search Results for PM Control Devices Installed on Cooling Towers

State	Equipment Description	Permit Date (issue date)	Throughput	Throughput Units	Control Description	Case-By-Case Basis	PM Emission Limit	PM Emission Limit Units
TX	Cooling tower	3/3/2010	0		Drift eliminators	BACT-PSD	0.0005	% DRIFT
TX	Cooling tower	2/3/2010	0		Drift eliminators	BACT-PSD	0.0005	% DRIFT
TX	Cooling tower	1/8/2010	0		Drift eliminators	BACT-PSD	0.0005	% DRIFT
NV	COOLING TOWERS - UNITS CC026, CC027, AND CC028 AT CITY CENTER	11/30/2009	10890	GAL/MIN	EACH UNIT IS EQUIPPED WITH A DRIFT ELIMINATOR LIMITING THE DRIFT RATE TO 0.001% AND THE TOTAL DISSOLVED SOLIDS IN THE CURCULATION WATER IS LIMITED TO 3,600 PPM.	LAER	0.091	LB/H
LA	COOLING TOWERS (13-81, 2004-6, 2005-42, 2005-43, 2008-35)	11/17/2009			DRIFT ELIMINATORS	BACT-PSD	0	
MN	COOLING TOWER	10/28/2009			DRIFT ELIMINATORS	BACT-PSD	0.01	LB/H
AL	COOLING TOWER	9/28/2009			DRIFT ELIMINATORS WILL BE INSTALLED, NOT MINIMIZE EMISSIONS.	BACT-PSD	0.4	T/YR PM10
NV	COOLING TOWER - UNIT BA14	8/20/2009	20400	GAL/MIN	BACT CONSISTS OF THE TWO REQUIREMENTS DESCRIBED IN THE PROCESS.	Other Case-by-Case	0.744	LB/H
NV	COOLING TOWER - UNIT FL17	8/20/2009	6900	GAL/MIN	DRIFT ELIMINATOR TO REDUCE DRIFT RATE TO LESS THAN 0.005% AND MAINTAINING TOTAL DISSOLVED SOLIDS CONTENT IN THE COOLING WATER TO BELOW 3,000 PPM.	Other Case-by-Case	0.425	LB/H
NV	COOLING TOWER - UNIT HA19	8/20/2009	7200	GAL/MIN	A DRIFT ELIMINATOR CONTROLS DRIFT RATE TO 0.005%, AND THE PERMITTEE IS REQUIRED TO MAINTAIN TSD CONTENT IN THE COOLING WATER TO A MAXIMUM OF 2,520 PPM.	Other Case-by-Case	0.215	LB/H
TX	COOLING TOWER	6/30/2009	165000	GAL/M	DRIFT ELIMINATORS	BACT-PSD	0.002	%
LA	COOLING TOWERS	6/22/2009	436000	GAL/MIN	DRIFT ELIMINATORS	BACT-PSD	1.64	LB/H
LA	COOLING TOWER (P-15)	2/27/2009	43000	GAL/MIN	GOOD DESIGN, MAINTENANCE, AND INTEGRATED DRIFT ELIMINATORS	BACT-PSD	0.057	LB/MM GAL
OH	COOLING TOWER	2/23/2009	2000	GAL/MIN	DRIFT ELIMINATOR	N/A	0.12	LB/H
OK	COOLING TOWER #1	2/23/2009	1.47	MMGAL/H	MIST ELIMINATORS	BACT-PSD	1.18	LB/H
OK	COOLING TOWER #2	2/23/2009	2.4	MMGAL/H	MIST ELIMINATORS	BACT-PSD	1.92	LB/H
ID	COOLING TOWER, SRC22	2/10/2009	121000	GAL/M	DRIFT/MIST ELIMINATORS	BACT-PSD	0.0005	% OF TOTAL CIRC FLOW
ID	ZLDS COOLING TOWER, SRC30	2/10/2009	985	GAL/M	DRIFT/MIST ELIMINATORS	BACT-PSD	0.001	% OF TOTAL CIRC FLOW
ID	COOLING TOWER, SRC22	2/10/2009	121000	GAL/M	DRIFT/MIST ELIMINATORS	BACT-PSD	0.0005	% OF TOTAL CIRC FLOW
ID	ZLDS COOLING TOWER, SRC30	2/10/2009	985	GAL/M	DRIFT/MIST ELIMINATORS	BACT-PSD	0.001	% OF TOTAL CIRC FLOW
OK	COOLING TOWER	1/23/2009	9	CELLS	DRIFT ELIMINATORS	BACT-PSD	0.4	LB/H/CELL
OH	COOLING TOWERS	11/20/2008	120425	T/H	HIGH EFFICIENCY DRIFT ELIMINATORS	BACT-PSD	2.4	LB/H
MD	COOLING TOWER	11/12/2008				BACT-PSD	0	
MD	COOLING TOWER	11/12/2008				BACT-PSD	0	
MD	COOLING TOWER	11/12/2008				LAER	0	
AR	COOLING TOWER	11/5/2008			DRIFT ELIMINATORS 0.0005% DRIFT RATE	BACT-PSD	5.2	LB/H
IA	COOLING TOWER	9/19/2008			DRIFT ELIMINATORS	BACT-PSD	0.0005	%
IA	COOLING TOWER	9/19/2008			DRIFT ELIMINATORS	BACT-PSD	0.0005	%
LA	COOLING TOWER	7/23/2008	0.01	% DRIFT RATE	GOOD OPERATING PRACTICES	BACT-PSD	1.4	LB/H
LA	EQT128 - COOLING TOWER (2M-7)	7/10/2008	106000	GAL/M	GOOD DESIGN, GOOD MAINTENANCE, AND MIST ELIMINATORS	BACT-PSD	0.06	LB/MMGAL
LA	COOLING TOWERS	5/28/2008	10750	GAL/M	DRIFT ELIMINATION SYSTEM	BACT-PSD	0.41	LB/H
AL	COOLING TOWER & STORAGE TANKS	5/20/2008			USE DRIFT ELIMINATORS AS OUTLINED IN THE RBLC.	BACT-PSD	0	
OH	COOLING TOWERS (12)	5/6/2008	1440000	GAL/H	DRIFT ELIMINATORS	BACT-PSD	3.42	LB/H
OH	COOLING TOWERS (12)	5/6/2008	1440000	GAL/H	DRIFT ELIMINATORS	LAER	3.42	LB/H
OK	COOLING TOWER	5/1/2008			HIGH-EFFICIENCY DRIFT ELIMINATOR	BACT-PSD	0	
LA	COOLING TOWER	3/20/2008	140000	GAL/MIN	USE OF MIST ELIMINATORS	BACT-PSD	1.4	LB/H
NV	COOLING TOWERS	2/26/2008			LIMIT OF TOTAL DISSOLVED SOLIDS IN THE CIRCULATING WATER TO 0.03 LBS/GAL, LIMIT OF THROUGHPUT TO 1,200 GAL/MIN, AND LIMIT OF DRIFT PERCENT TO 0.005	Other Case-by-Case	0.051	LB/H

APPENDIX E

BACT COST ANALYSIS CALCULATIONS

Table E-1. Power Boiler 10 Parameters

Parameter	Value	Units	Comment/Reference
Exhaust flow rate	100,836	DSCFM	Confirmed by PTPC.
Exhaust temperature	142	F	Confirmed by PTPC.
Uncontrolled VOC emissions	18	tpy	Projected actual emissions for the Power Boiler 10; calculation details are provided in Appendix B of the application report.
Uncontrolled CO emissions	635	tpy	Projected actual emissions for the Power Boiler 10; calculation details are provided in Appendix B of the application report.
Assumed control efficiency	95%		EPA Air Pollution Control Technology Fact Sheet: EPA-452/F-03-018, example catalytic unit achieving 95% efficiency for VOC. This efficiency is also conservatively used to estimate CO controlled emissions.
Controlled VOC emissions	0.91	tpy	Calculated using the control efficiency.
Controlled CO emissions	32	tpy	Calculated using the control efficiency.
Chemical Engineering Plant Cost Index for 1999	390.6		CE Plant Cost index for 1999 (www.che.com)
Chemical Engineering Plant Cost Index for 2010	539.1		CE Plant Cost index for February 2010, preliminary (www.che.com)

Table E-2. Catalytic Oxidation Parameters

Parameter	Value	Units	Comment/Reference
Boiler Flow Rate	452,582	lbs/hr	Converted volumetric exhaust flow rate to mass basis by assuming that the typical molecular weight of dry air (28.95 lbs/lbmol) is representative of the exhaust stream.
Oil Price	9.27	$/MMBtu	Provided by PTPC. Assumed the following: a oil cost of $55/barrel; a density of 7.4 lb/gal; and a heating value of 19,100 lbs/Btu.
Exhaust Temp of Boiler (pre-control)	142	^{o}F	Confirmed by PTPC.
Desired Temp	840	^{o}F	EPA Air Pollution Control Technology Fact Sheet: EPA-452/F-03-018, example catalytic unit achieving 95% efficiency.
Average Heat Capacity	0.248	Btu/(lb*^{o}F)	Mean heat capacity of air between 77^{o}F and 780^{o}F (OAQPS, EPA Air Pollution Control Cost Manual, Sixth Edition, Sec 3.2, Chpt 2, page 2-31); assumed to be representative of heat capacity at temperature range of interest.
Heat Required	173	Btu/lb	Heat required to increase exhaust temperature to desired temperature
Heat Required	78,343,836	Btu/hr	Heat required to increase exhaust temperature to desired temperature
Heat Required	78.3	MMBtu/hr	Heat required to increase exhaust temperature to desired temperature
Heat Required	686,292	MMBtu/yr	Assuming no heat recovery.

Table E-3. Power Boiler 10
Cost Analysis for the Control of VOC/CO with Catalytic Oxidation Technology
Capital Cost Summary

Direct Costs		**Basis**	**Value**	**Reference**
Purchased Equipment Cost				
Basic + Auxiliary Equipment	BE	BE	$833,254 [a]	OAQPS Sixth Edition
Instrumentation		BE*0.10	$83,325 [b]	OAQPS Sixth Edition
Sales Tax		BE*0.084	$69,993 [b]	Washington Dept. of Revenue
Freight		BE*0.05	$41,663 [b]	OAQPS Sixth Edition
Total Purchased Equipment Cost	PEC	SUM	$1,028,236	Calculation
Installation Costs				
Foundations and Supports		PEC*0.08	$82,259 [b]	OAQPS Sixth Edition
Handling and Erection		PEC*0.14	$143,953 [b]	OAQPS Sixth Edition
Electrical		PEC*0.04	$41,129 [b]	OAQPS Sixth Edition
Piping		PEC*0.02	$20,565 [b]	OAQPS Sixth Edition
Insulation for ductwork		PEC*0.01	$10,282 [b]	OAQPS Sixth Edition
Painting		PEC*0.01	$10,282 [b]	OAQPS Sixth Edition
Total Direct Installation Costs	DIC	SUM	$308,471	Calculation
Site Preparation	SP		[c]	Not estimated
Buildings	B		[c]	Not estimated
Total Direct Costs	TDC	PEC + DIC + SP + B	$1,336,706	Calculation
Indirect Costs				
Engineering		PEC*0.10	$102,824 [b]	OAQPS Sixth Edition
Construction and Field Expenses		PEC*0.05	$51,412 [b]	OAQPS Sixth Edition
Contractor Fees		PEC*0.10	$102,824 [b]	OAQPS Sixth Edition
Start-up		PEC*0.02	$20,565 [b]	OAQPS Sixth Edition
Performance Test		PEC*0.01	$10,282 [b]	OAQPS Sixth Edition
Contingencies		PEC*0.03	$30,847 [b]	OAQPS Sixth Edition
Total Indirect Cost	TIC	SUM	$318,753	Calculation
Total Capital Investment (TCI)		**TDC + TIC**	**$1,655,459**	**Calculation**

[a] Applied Equation 2.34 of Office of Air Quality Planning and Standards (OAQPS), EPA Air Pollution Control Cost Manual, Sixth Edition, Sec 3.2, Chpt 2, to estimate the basic equipment costs of a catalytic incinerator with 0% heat recovery. This equation is then multiplied by the ratio of the 1999 and 2010 chemical engineering index.

[b] Table 2.8 of OAQPS, EPA Air Pollution Control Cost Manual, Sixth Edition, Sec 3.2, Chpt 2. Sales tax is estimated based on the tax rate in Port Townsend, WA.

[c] Costs not included in estimate.

Table E-4. Power Boiler 10

Cost Analysis for the Control of VOC/CO with Catalytic Oxidation Technology
Annual Cost Summary

Direct Operating Cost	Basis	Value	Reference
Catalyst Replacement			
Catalyst Cost	Guaranteed for 3 Years	$166,651	Assume 20% BE
Catalyst life	Every 3 Year	2 [a]	OAQPS Sixth Edition
Catalyst Cost Recovery Factor	3 Year, 7% Interest	0.55 [b]	OAQPS Sixth Edition
Total Cost ($/yr)		$92,173	Calculation
Maintenance			
Labor	0.5 hours per shift	$10,649 [c]	OAQPS Sixth Edition
Materials	100% of maintenance labor	$10,649 [c]	OAQPS Sixth Edition
Operating Labor			
Operator	0.5 hours per shift	$13,857 [c]	OAQPS Sixth Edition
Supervisor	15% of operator	$2,079 [c]	OAQPS Sixth Edition
Utility Costs			
Fan	kWh/yr	1,008,769 [d]	OAQPS Sixth Edition
Electric Utility Rate	$/kWh	$0.0425 [e]	DOE Electricity Costs
RFO Usage	MMBtu/yr	686,292 [f]	Energy Balance, 0% Heat Recovery
RFO Rate	$/MMBtu	$9.27 [g]	PTPC
Total Cost ($/yr)		$6,401,410	Calculation
Total Direct Cost ($/yr)	DC	$6,530,817	
Indirect			
Overhead	60% of O&M Costs	$22,340 [a]	OAQPS Sixth Edition
Administrative Charges	2% of TCI	$33,109 [a]	OAQPS Sixth Edition
Property Tax	1% of TCI	$16,555 [a]	OAQPS Sixth Edition
Insurance	1% of TCI	$16,555 [a]	OAQPS Sixth Edition
Cost Recovery Factor (CRF)	10 Years, 7% Interest	0.142 [b]	OAQPS Sixth Edition
Capital Recovery	CRF*TCI	$235,700 [a]	Calculation
Total Indirect ($/yr)	IAC	$324,259	Calculation
Total Annual Cost	**TAC=DAC+IAC**	**$6,855,076**	

[a] Per Table 2.10 of OAQPS, EPA Air Pollution Control Cost Manual, Sixth Edition, Sec 3.2, Chapt 2.

[b] Equation 2.55 of OAQPS, EPA Air Pollution Control Cost Manual, Sixth Edition, Sec 4.2, Chapt 2.

[c] Maintenance labor wage rate of $19.45/hour based on mean average for "Maintenance and Repair Workers, General" and operating labor wage rate of $26.46/hour based on mean average for "Plant and System Operators, All Other" for Washington in May 2009; from the Bureau of Labor Statistics (http://www.bls.gov/oes/2009/may/oes_wa.htm). Maintenance labor assumed to be 0.5 hrs per shift and maintenance materials assumed to be 100% of labor, per Table 2.10 of OAQPS, EPA Air Pollution Control Cost Manual, Sixth Edition, Sec 3.2, Chapt 2.

[d] Per Equation 2.42 of OAQPS, EPA Air Pollution Control Cost Manual, Sixth Edition, Sec 3.2, Chapt 2. The pressure drop was conservatively assumed to be 6 in H_2O for a catalytic incinerator (Table 2.11) and a fan efficiency of 70 percent was assumed (page 2-41). Note that the standard flow rate is corrected to the flow rate at actual conditions. Continuous operation of 8760 hr/yr is assumed.

[e] Per Energy Information Administration (EIA) Official Energy Statistics from the U.S. Government website, the average retail price of electricity for the industrial sector in Washington state in 2010 (through February 2010) is $0.0424/kWh (http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_b.html).

[f] Energy required to heat exhaust stream from 141^{o}F (max outlet temp of the Power Boiler 20) to 840^{o}F (temperature provided in EPA Air Pollution Control Technology Fact Sheet: EPA-452/F-03-018 from a catalytic unit achieving 95% efficiency), assuming 0 % heat recovery.

[g] Oil cost of $55 per barrel; an oil density of 7.4 lb/gal; and a heating value of 19,100 lbs/Btu, as provided by PTPC.

Table E-5. Power Boiler 10

Cost Analysis for the Control of VOC/CO with Catalytic Oxidation Technology
Cost Effectiveness Summary

Uncontrolled VOC emission rate (ton/yr)	18 [a]
Controlled VOC emission rate with catalytic oxidation (ton/yr)	1 [b]
Uncontrolled CO emission rate (ton/yr)	635 [a]
Controlled CO emission rate with catalytic oxidation (ton/yr)	32 [b]
Additional VOC and CO removed by catalytic oxidation (ton/yr)	620
Total Annual Cost (TAC) of adding oxidation technology to uncontrolled operations	$6,855,076
Cost Effectiveness of adding oxidation catalyst to uncontrolled operations ($/ton VOC and CO removed)	$11,054

[a] Based on design emission factors per the Harris Group, a maximum heat input rate of 414 MMBtu/hr, and continuous operations of 8760 hrs/yr.

[b] Assumed 95% control efficiency per U.S. EPA, Air Pollution Control Technology Sheet, Fact Sheet: EPA-452/F-03-018.

Table E-6. Power Boiler 10 Parameters

Parameter	Value	Units	Comment/Reference
Exhaust flow rate	100,836	SCFM	Exhaust flow rate from Emissions tab
Exhaust temperature	142	F	Exhaust temperature from Emissions tab
Uncontrolled VOC emissions	18	tpy	Projected actual emissions for the Power Boiler 10; calculation details are provided in Appendix B of the application report.
Uncontrolled CO emissions	635	tpy	Projected actual emissions for the Power Boiler 10; calculation details are provided in Appendix B of the application report.
Assumed control efficiency	98%	tpy	EPA Air Pollution Technology Fact Sheet: EPA-452/F-03-022, example thermal oxxidizer achieving 98% control efficiency.
Controlled VOC emissions	0.36	tpy	Calculated using the control efficiency.
Controlled CO emissions	13	tpy	Calculated using the control efficiency.

Table E-7. Auxillary Fuel Cost for Thermal Oxidation

Parameter	Value	Units	Comment/Reference
Boiler Flow Rate	452,582	lbs/hr	Converted volumetric exhaust flow rate to mass basis by assuming that the typical molecular weight of dry air (28.95 lbs/lbmol) is representative of the exhaust stream.
Oil Price	9.27	$/MMBtu	Provided by PTPC. Assumed the following: a oil cost of $55/barrel; a density of 7.4 lb/gal; and a heating value of 19,100 lbs/Btu.
Exhaust Temp of Boiler (pre-control)	142	^{o}F	Exhaust temperature from Emissions tab
Desired Temp	1600	^{o}F	EPA Air Pollution Technology Fact Sheet: EPA-452/F-03-022, example thermal oxidizer achieving 98% control efficiency.
Average Heat Capacity	0.255	Btu/(lb*^{o}F)	Mean heat capacity of air between 77^{o}F and 1375^{o}F (OAQPS, EPA Air Pollution Control Cost Manual, Sixth Edition, Sec 3.2, Chpt 2, page 2-26); assumed to be representative of heat capacity at temperature range of interest.
Heat Required	372	Btu/lb	Heat required to increase exhaust temperature to desired temperature
Heat Required	168,265,637	Btu/hr	Heat required to increase exhaust temperature to desired temperature
Heat Required	168.3	MMBtu/hr	Heat required to increase exhaust temperature to desired temperature
Heat Required	1,474,007	MMBtu/yr	Assuming no heat recovery (per EPA-452/F-03-022, thermal incinerators do not include heat recovery)
Auxillary Fuel Cost	$13,656,766	$/yr	
Cost Effectiveness	$21,348	$/ton removed	This only accounts for fuel costs, and not the equipment/operating costs of the thermal oxidizer.