DEPARTMENT OF
ECOLOGY
State of Washington

TECHNICAL SUPPORT DOCUMENT FOR PREVENTION OF SIGNIFICANT DETERIORATION PSD 06-02, AMENDMENT 1

Steam Turbine Generator Project
WestRock Tacoma Mill
Tacoma, Washington

Prepared by

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EXECUTIVE SUMMARY

In May of 2014, RockTenn CP, LLC purchased the Simpson Tacoma Kraft mill and changed the mill's name to the RockTenn Tacoma Mill. As of September 1, 2015, RockTenn CP, LLC changed its name to WestRock CP, LLC. For consistency, the mill will be referred to as the WestRock Tacoma Mill or just Tacoma Mill in this document, even though most of the actions discussed in this document were implemented under Simpson's ownership.

In October 2006, the Tacoma Mill completed installation of an overfire air (OFA) system to allow utilization of more biomass (hog fuel) and decrease the usage of fossil fuels in the No. 7 Power Boiler.

In September 2006, the Tacoma Mill applied for a PSD permit (PSD-06-02) from the Washington State Department of Ecology (Ecology) to install a steam turbine electrical generator driven by steam produced from the existing No. 4 Recovery Boiler and No. 7 Power Boiler, and to upgrade portions of No. 7 Power Boiler to provide more and higher pressure steam. The biomass feed system to No. 7 Power Boiler was upgraded to allow full operation of the boiler on biomass (hog fuel, urban wood, wastewater treatment residuals), and old corrugated container rejects (OCC rejects) using minimal fossil fuel to start-up and also to stabilize combustion. The PSD permit was issued in May 2007. The steam turbine became operational July 1, 2009.

The emission limits proposed in the September 2006 PSD permit application were based on the estimated future performance of the new OFA system. The NO_X emissions turned out to be higher than predicted by the engineering firm that supplied the OFA system, and was also higher than the PSD's permitted limits. With this current PSD modification application, the Tacoma Mill is requesting to correct this error in the original NO_X BACT determination. The short-term NO_X BACT emission limit is requested to be changed from 0.20 lb NO_X/MMBtu fuel to 0.30 lb/MMBtu on a 30-day rolling average. This will require the annual NO_X emission limit to be changed from 522 to 782 tons per year. No other changes are requested, and no new physical construction is proposed.

The Washington State Department of Ecology finds the applicant, the WestRock Tacoma Mill, has satisfied all requirements for approval of the proposed PSD permit modification to increase the No. 7 Power Boiler NO_X emission limits as proposed.

1. INTRODUCTION

1.1. The PSD Process

The Prevention of Significant Deterioration (PSD) procedure is implemented under Washington Administrative Code (WAC) 173-400-700 to 750. These rules require PSD review of all new or modified air pollution sources that emit a regulated pollutant at rate greater than a level listed in the PSD program rules. The objective of the PSD program is to prevent serious adverse environmental impact from emissions into the atmosphere by a proposed new or modified source. PSD rules require that an applicant use the most effective air pollution control equipment and procedures after considering environmental, economic, and energy factors. The program sets up a mechanism for evaluating and controlling air emissions from a proposed source to minimize the impacts on air quality, visibility, soils, and vegetation.

Washington State implements its PSD program under Washington regulations 173-400 700 to 750 as a SIP approved program. This SIP approved program became effective May 29, 2015[1]

1.2. The Project

1.2.1. The site

WestRock CP, LLC (WestRock) operates a pulp and paper mill located at 801 Portland Avenue in Tacoma (Tacoma Mill). The Tacoma Mill was originally built in 1928 by the Union Bag Company. It is situated on a peninsula bordered by the mouth of the Puyallup River on the northeast, Inner Commencement Bay on the northwest, and the St. Paul CDF (former St. Paul Waterway) on the southwest. The mill manufactures bleached and unbleached kraft pulp and linerboard, and generates electricity for sale to the power grid using excess boiler steam.

1.2.2. The proposal

For this amendment to PSD 06-02, the Tacoma Mill is proposing to correct the original permit's NO_X BACT determination by an increase in the No. 7 Power Boiler's NO_X limit from 0.20 to 0.30 lb/MMBtu. The annual NO_X emission limit is also requested to be changed from 522 tons to 782 tons. This reflects the annualized tonnage that would be emitted if the boiler were operated at the short-term limit for 8,760 hours. No other permit term revisions are requested, and no additional construction or physical modifications are requested. The following is information supporting this request.

The Tacoma Mill currently generates steam for general mill operations using No. 4 Recovery Boiler, No. 6 Power Boiler, and No. 7 Power Boiler. Under PSD 06-02, the Tacoma Mill installed a 60 MW nominal-sized steam turbine generator using steam produced from No. 4 Recovery Boiler and No. 7 Power Boiler. The steam turbine operated power generator became operational July 1, 2009. This cogeneration project (called the Project from here on) was intended to allow the Tacoma

[1] 80 FR 23721, April 29, 2015.

Mill to generate steam for plant use and to produce and distribute electrical power using primarily biomass fuel with a minimum additional fossil fuels (e.g., fuel oil or natural gas).

The main features of the original condensing steam turbine generator project included the purchase and installation of:

- A steam turbine and electrical generator rated at up to 60 MW.
- Power distribution and overload protection equipment.
- A building to house the turbine/generator.
- Upgrades to the demineralizer system to produce the higher-quality boiler feedwater required for power generation.
- A cooling tower to condense the turbine discharge steam that is not used in the process.
- Boiler improvements to produce the higher pressure and temperature steam required for power generation. These improvements include adding tube area to #7 Power Boiler's superheater section, upgrading the pressure rating of #4 Recovery Boiler's generation bank, new pressure safety valves, and piping changes to handle higher pressure steam.
- Upgrades to No. 7 Power Boiler to increase its Maximum Continuous Rated (MCR) steaming capacity from 300,000 lb/hr to 340,000 lb/hr using biomass fuel. These included larger forced-draft and induced-draft fan motors, wood fuel feed system improvements, and improvements to the ash handling, electrostatic precipitator, and other ancillary systems. An engineering study concluded that 340,000 lb/hr is the maximum steam production that No. 7 Power Boiler could sustain without significant upgrades to other boiler components.

On April 21, 2006, Ecology's Industrial Section approved the OFA project in Notice of Construction (NOC) Order No. 3255-AQ06 as a substantial alteration to pollution control technology. In the fall of 2006, the Tacoma Mill installed the OFA system on the No. 7 Power Boiler. The OFA system was installed to improve the distribution of combustion air in the furnace, allowing the Mill to burn more wood and less fossil fuels while maintaining compliance with an existing carbon monoxide (CO) limit. The OFA project did not change the MCR of the boiler, but the installed OFA system was capable of accommodating the higher MCR (340,000 lb/hr) resulting from upgrades supporting the PSD permitted Project.

The PSD Project application submitted in September 2006 used baseline emission periods from before the OFA project, and emission factors based on its expected performance, so the PSD permitting for the Project included the effects of the OFA project and subjected all major No. 7 Boiler pollutants (NO_X, CO, and particulate matter less than 10 microns (PM_{10})) to BACT. Since the OFA system had not been completely installed at the time of preparation of the PSD Project application, the PSD BACT limits were based on its expected performance.

PSD 06-02 was issued to the Tacoma Mill on May 22, 2007. The Mill ordered some of the long lead time equipment beginning in July 2007, and began actual physical construction by mid-2008. The Tacoma Mill has installed and is operating the higher capacity fans and other modifications that allow the boiler to operate at its full design rate and steam pressure.

The steam turbine became operational and began generating commercial power on July 1, 2009. When the Mill began running the #7 Boiler at the higher operating rates needed to supply steam to this turbine, it found that the OFA system did not reduce NOx emissions to the initially estimated level. Representatives of the Tacoma Mill met with Ecology AQP and the Industrial Section to discuss a solution for this issue. Ecology's Industrial Section and the Tacoma Mill agreed in a consent order that the Mill could operate under a temporary 0.30 lb/MMBtu NOx emission limit until the Mill applied for and received a corrected NOx BACT limit in its existing PSD permit. The corrected NOx limit is requested in this application.

1.3. PSD Applicability and Air Pollutant Emissions

The Tacoma Mill is an existing major source[2] of a regulated pollutant.[3] The No. 7 Power Boiler currently operates under PSD 06-02 (issued by Washington State under United States Environmental Protection Agency (EPA) delegation) and a minor NSR permit from Ecology's Industrial Section. It also has a Title V air permit.

As discussed in Section 1.1 of this document, Washington State issues PSD permits under its own SIP approved program. As discussed below, WAC 173-400-750 contains provisions applicable to revising a PSD permit. These provisions have their genesis in existing EPA guidance. They are not all inclusive of EPA guidance, so any EPA guidance may be referred to as necessary to appropriately revise a PSD permit.

EPA guidance allows an agency to revise BACT emission limits if sufficient emission reductions cannot be reasonably achieved after the source makes efforts to comply with the permit limits and reduce emissions to a lower level. This requires reopening the BACT analysis. In the process of reevaluating BACT, current BACT technology and requirements must be considered.[4] These issues are addressed in the sections below.

WAC 173-400-750 allows Ecology to revise PSD permit conditions if certain criteria are met. The criteria, and the reasons that the criteria are met in this case, are listed below:

> **(a) The change in conditions will not cause the source to exceed an emissions standard established by regulation**. NO_X is the only pollutant affected by the proposed permit amendment. The only emission standard potentially applicable to NO_X emissions from the boiler are contained in New Source Performance Standard (NSPS) Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The new proposed limit is consistent with the NSPS Subpart Db limit of 0.30 lb/MMBtu.
>
> **(b) No ambient air quality standard or PSD increment will be exceeded as a result of the change**. As discussed later, the predicted NO_X concentration from the facility is below

[2] Kraft pulp mills are a major source under PSD regulations if they, in total, have the potential to emit more than 100 tpy of a pollutant regulated by the PSD permitting program. WAC 173-400-720(4)(a)(v) and 40 CFR 52.21(b)(1)(i)(a).
[3] The PSD program directly regulates a list of specific pollutants listed in 40 CFR 52.21(b)(23). These are referred to as "regulated pollutants." PSD regulates other pollutants indirectly through the broad categories of "regulated" pollutants such as VOC and particulates. In Washington State, the local air authority issues its own permit that complements the PSD permit and includes all emissions regulated by state and local regulations. WAC 173-400-113.
[4] EPA's Memorandum, *Request for Determination on Best Available Control Technology (BACT) Issues – Ogden Martin Tulsa Municipal Waste Incinerator Facility*, November 19, 1987.

the National Ambient Air Quality Standard (NAAQS) and PSD Increment Standard (Increment).

(c) The change will not adversely impact the ability of Ecology or the authority to determine compliance with an emissions standard. The Tacoma Mill will continue to operate the CEMS to monitor NO_X, CO, and oxygen to determine compliance with the emission standards.

(d) The revised PSD permit will continue to require BACT, as defined at the time of the original PSD permit, for each new or modified emission unit approved by the original PSD permit. The conclusions in the original BACT analysis have not changed, except that since the application was submitted, CEMS data have indicated that the boiler cannot meet the existing NO_X emission limits on a continuous basis while maintaining compliance with CO emission limits. Further discussion of BACT is provided later.

(e) The revised PSD permit continues to meet the requirements of WAC 173-400-800, and 173-400-113, as applicable. As discussed in the following sections, the proposed amendment does not affect compliance with the requirements for new sources in nonattainment areas or new sources in attainment or unclassifiable areas.

An EPA guidance (the "Ogden Memo" reference 4) specifies that an inappropriately permitted BACT level may be corrected using the newly determined correct data and assumptions if:

1. The units were constructed in conformity with the existing permit.
2. The permitted BACT levels were a result of errors, faulty data, or incorrect assumptions contained in the permit application.
3. The source has investigated all available options to reduce emissions and demonstrated that compliance cannot be achieved.

If the modification is determined to meet the above conditions, then the permit modification must include:

4. A revised BACT determination for the pollutant addressing current technology and requirements.
5. Consideration of all other PSD requirements which may be affected by an allowable increase (e.g., protection of the standards and increments, additional impacts, monitoring).

A discussion of those issues follows.

Whether the source was constructed in conformity with the permit

The 2007 PSD permit approved The Tacoma Mill's application to make modifications to emission units at the facility to construct and operate the electric steam generating project. These modifications included changes to the No. 7 Power Boiler, as set forth in the Findings section of the permit:

- Boiler improvements to produce the higher pressure and temperature steam required for power generation. These improvements included adding tube area to No. 7 Power Boiler's

superheater section, upgrading the pressure rating of No. 4 Recovery Boiler's generation bank, new pressure safety valves, and piping changes to handle higher pressure steam.

- Upgrades to No. 7 Power Boiler to increase its Maximum Continuous Rated (MCR) steaming capacity from 300,000 lb/hr to 340,000 lb/hr. These included larger forced draft and induced draft fan motors, wood fuel feed system improvements, and improvements to the ash handling, electrostatic precipitator, and other ancillary systems.

Neither the 2006 PSD permit application nor the final 2007 PSD permit completely describes all of the improvements and upgrades to the No. 7 Power Boiler that would be implemented to achieve the projects goals; however, based on the additional information provided, both Ecology and the EPA conclude that, as constructed, the No. 7 Power Boiler does conform to the application and permit and has since start-up in 2009 been producing approximately 300,000 lb/hr of high pressure and temperature steam for power generation while burning permitted fuels. Steam production has periodically reached 340,000 lb/hr hourly production rates.

Whether the permitted BACT levels are inappropriate as a result of errors, faulty data, or incorrect assumptions contained in the permit application

In its request for a revision to the 2007 PSD permit, the Tacoma Mill asserted there was an error in the original NO_X BACT determination, but neither the Mill's 2010 revision application nor Ecology's 2010 draft permit revision included information to adequately support that contention. The additional information that the Tacoma Mill and Simpson recently provided to Ecology supports the Mill's claim of error in the original BACT determination. Also, there is no indication that that the Tacoma Mill intentionally acted to misrepresent or conceal data in its original and modified permit applications and BACT analysis.

The NO_X BACT determination for the No. 7 Power Boiler included in the 2007 PSD permit was based on "good combustion practices," including the use of a new OFA system, when burning biomass. The permit's 30-day rolling average NO_X BACT limit of 0.20 lb/MMBtu was based on an overly optimistic assumption provided by the system vendor regarding the performance of the new OFA system along with the erroneous use of historic annual average emissions data instead of the more appropriate, and higher, 30-day rolling average emissions, as well as a failure to anticipate worst case emissions from permitted biomass fuel mixtures. The compounded effect of these types of errors resulted in a 30-day rolling NO_X BACT limit that could not be met on a continuous basis when the permitted fuels were burned and good combustion practices were used.

An incorrect determination of the NO_X "BACT floor" also contributed to the error in the NO_X BACT permit limit. The definition of BACT at 40 CFR §52.21(b)(12) requires that the application of BACT would not result in emissions that would exceed the emissions allowed under any applicable standard under 40 CFR parts 60 or 61 (the "BACT floor"). The NO_X BACT limit was based on a mistake about which NO_X standard in 40 CFR part 60, subpart Db was the "applicable" standard for No. 7 Power Boiler at the time the permit was issued. The record reflects that Ecology incorrectly assumed at the time of permit issuance that the No. 7 Power Boiler would no longer be subject to a NO_X standard as a result of a requested 10 percent limit on the use of oil and then incorrectly assumed that the "applicable" standard for purposes of the NO_X "BACT floor" would be the limit for new or reconstructed sources of 0.20 lb/MMBtu in 40 CFR §60.44b(l). Ecology and

WestRock have since recognized that the No. 7 Power Boiler was, and still is, subject to the NO_X limit of 0.30 lb/MMBtu in 40 CFR §60.44b(d) because there is no enforceable limit on the use of natural gas. Because this is the 40 CFR part 60 standard actually applicable to the boiler, 0.30 lb/MMBtu and not 0.20 lb/MMBtu is the "BACT floor" for this source.

In summary, based on the additional information now in the permit record, Ecology and EPA agree that the original BACT NO_X limit in the 2007 PSD permit was based on errors and incorrect assumptions.

Whether the source has investigated all available options to reduce emissions and demonstrated that compliance cannot be achieved

Prior to any attempt to revise or adjust an existing BACT limit, a source has an obligation to demonstrate that it has investigated all available options to reduce emissions to a lower (if not permitted) level and that compliance with the BACT permit limit cannot reasonably be achieved. The Tacoma Mill's 2010 revision to the Project permit application include a description of the efforts it has undertaken to reduce NO_X emissions at the No. 7 Power Boiler (see description below). The additional information provided subsequent to EPA's March 3, 2013, letter includes a demonstration that the No. 7 Power Boiler at the Tacoma Mill cannot comply with the current NO_X BACT limit through further boiler optimization. The Tacoma Mill also submitted significant new information on NO_X emissions, fuels combusted (including chloride (Cl) content), and hydrogen chloride emissions to support the control technology evaluation in its updated BACT analysis (see Section 2.4). Based on the additional information now in the permit record, Ecology and EPA agree that WestRock has investigated all available options to reduce emissions and has demonstrated that compliance with the current NO_X BACT limit cannot be achieved.

The Tacoma Mill's Effort to Reduce Emissions

In Chapter 5 of the application, the Tacoma Mill provided an extensive list of the original project's construction time table, and the Mill's efforts to decrease and maintain NO_X emissions. This showed a continuous construction and No. 7 Power Boiler modification program through June 2010 when the application was prepared. The boiler ran continuously during this time to provide process steam to ongoing pulp and paper mill production except when its shutdown was necessary to facilitate the construction activities. After installation of the new steam turbine began, the modified boiler has been operated at up to its design steam production rate and pressures.

Even though the Tacoma Mill has been implementing actions to minimize NO_X emissions and keep NO_X below the PSD BACT limits, its CEMS data has shown that the boiler is unable to demonstrate continuous compliance with the 0.20 lb/MMBtu NO_X limit.

Emissions

The Tacoma Mill is proposing to correct the No. 7 Power Boiler's BACT limit for NO_X from 0.20 to 0.30 lb/MMBtu. This would also require a revision of the annual NO_X limit from 522 tons to 782 tons based on the revised BACT limit, for an annual NO_X increase of 260 tons per year (tpy). The

Mill analyzed the NO_X increase as if it was from the original project's NO_X baseline of 289 tpy for an overall NO_X emissions increase due to the project of 493 tpy.

No. 7 Power Boiler burns a range of fuels, including natural gas, oil, wood, wastewater treatment residuals, and old corrugated container (OCC) fiber-derived fuel. Emissions from the No. 7 Power Boiler vary with firing rate and with the fuels burned. Emissions also vary with the moisture content of the biomass. Higher moisture contents in winter months tend to increase CO concentrations in the exhaust gas. One of the beneficial aspects of the steam turbine project is that swings in boiler load are reduced because steam not needed in the pulp and paper process is used for additional electricity generation. Reduced boiler load swings improve combustion of solid fuels in the boiler and minimize emissions variability.

The Mill employs Continuous Emission Monitoring Systems (CEMS) to monitor and record NO_X and CO concentrations from the No. 7 Power Boiler. Using stack flow calculated from fuel input and the concentrations from the CEMS, the Mill calculates hourly NO_X and CO mass emissions. Under PSD applicability procedures,[5] PSD applicability of a pollutant is dependent on its level of annual emissions. The Net Emissions Increase (NEI) due to a project is calculated from the difference between the plant's Baseline Actual Emissions (BAE)[6] and Projected Actual Emissions (PAE).[7] For Amendment 1, NO_X emissions increases are evaluated as they would have been if they were proposed in the original project application, not just as an increase from emissions allowed by the project PSD. Table 1-1 shows the results of this calculation.

Table 1-1. Summary of NO_X Baseline and Projected Actual Emissions

	Original Project	Amendment 1 Proposal
Existing (annual average)* (lb/hr)	65.9	65.9
Future (at MCR)† (lb/hr)	119.1	178.6
Increase in hourly emissions (lb/hr)	53.2	112.7
Baseline years	2000-2001	2000-2001
Baseline emissions (tpy)	289	289
Future potential emissions (tpy)	522	782
Difference (tpy)	233	493
PSD applicability trigger (tpy)	40	40
PSD applicable?	**Yes**	**Yes**

∗ Estimated by dividing baseline annual emissions by 355 days of 24-hr operation.
† Assumes 365 days/yr of operation at Maximum Capacity Rating (MCR).

[5] 40 CFR 52.21(a)(2).
[6] 40 CFR 52.21(b)(48).
[7] 40 CFR 52.21(b)(41).

1.4. New Source Performance Standards

EPA has established performance standards for a number of air pollution sources in 40 CFR part 60. NSPS usually represent a minimum level of control that is required of a new source.

NSPS Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units) regulates emissions from boilers that are constructed, reconstructed, or modified after June 19, 1984, and have a heat input greater than 100 MMBtu/hr. Subpart Db currently applies to No. 7 Power Boiler.

Subpart Db limits NO_X emissions to 0.30 lb/MMBtu, averaged over a rolling 30-day period to fossil fuel burning boilers, and this limit is applicable to No. 7 Power Boiler. WestRock can burn oil or natural gas along with biomass fuel in No. 7 Power Boiler. The boiler's federally enforceable minor NSR permit contains an annual fossil fuel capacity factor of less than 10 percent of the boiler's design heat input for oil, but not for natural gas. This makes 40 CFR 60.44b(c) not applicable, but 60.44b(d) is still applicable. WestRock monitors NO_X emissions using CEMS and flow rates calculated from fuel feed.

1.5. State Regulations

The Tacoma Mill is subject to both PSD and minor source NOC permitting requirements under State of Washington regulations Chapters 173-400 and 173-460. Ecology's Industrial Section is the permitting authority for all air emission regulatory requirements not included in PSD permitting. This includes the NSR permitting of air toxics issues under federal MACT and state 173-460 WAC, and Title V permitting requirements. The proposed amendment will not trigger state requirements for the Industrial Section to modify the Mill's existing NOC permit.

The Industrial Section will be responsible for enforcement of all provisions of the PSD after they are included in the facility's Title V permit, and in the interim between permit issuance and that time.

2. DETERMINATION OF NO_X BEST AVAILABLE CONTROL TECHNOLOGY

All new and significantly modified sources are required to use Best Available Control Technology (BACT), which is defined in 40 CFR 52.21(b)(12) as an emissions limitation based on the maximum degree of reduction for each pollutant subject to regulation, emitted from any proposed major stationary source or major modification, on a case-by-case basis, taking into account cost-effectiveness, economic, energy, environmental, and other impacts.

The "top-down" BACT process starts by considering the most stringent form of emissions reduction technology possible, then determines if that technology is technically feasible and economically justifiable. If the technology is proven infeasible or unjustifiable, then the next less stringent level of reduction is considered. When an emission reduction technology meets the stringency, and technical and economic feasibility criteria, it is determined to be BACT.

Under the PSD 06-02 permit, the Tacoma Mill installed a steam turbine generator driven by steam produced from No. 4 Recovery Boiler and No. 7 Power Boiler. Upgrades to the No. 7 Power Boiler to increase its Maximum Continuous Rated (MCR) steaming capacity from 300,000 lb/hr to 340,000 lb/hr (595 MMBtu/hr) were also allowed by that permit. Because there would be an emission increase associated with use of this additional steam capacity, the Mill conducted an analysis for pollutants emitted by No. 7 Power Boiler to ensure that BACT was applied.

For this permit amendment, WestRock is proposing to correct the No. 7 Power Boiler's BACT limit for NO_X from 0.20 to 0.30 lb/MMBtu. This will also require a revision of the annual NO_X emission limit from 522 tons to 782 tons based on the corrected BACT limit. To allow this, Ecology has asked that the Tacoma Mill review the initial permit's NO_X BACT as if the original permit had proposed the new short- and long-term limits that are requested in this amendment. This BACT review is limited and requires that the original BACT determination be updated with better information, such as better knowledge of the post-modification NO_X emissions from the boiler, better knowledge of the hydrogen chloride (HCl) concentrations in the exhaust stream, and better knowledge of control costs. It is not a new BACT determination based on current technologies and requirements as well as this better information, although the discussions do show that no new technologies or improvements in current technologies were found that would affect BACT. No physical changes are requested for the boiler, and no changes in its operation are requested other than the NO_X limit correction. As discussed in Section 1.3, no other BACT determinations from the initial permit are required to be reviewed.

NO_X is generated when combustion temperatures are high enough for the nitrogen in the combustion air or nitrogen bound in the fuel to combine with oxygen to form NO. Depending upon conditions, some portion of the NO will react further to form NO_2.

The determination of NO_X BACT at the Tacoma Mill is complicated by the presence of high levels of Cl in the boiler fuels. Cl can react with ammonia (from possible NO_X reduction technologies) to form ammonium chloride (NH_4Cl), which can turn the boiler's stack emissions from clear to a visible white plume. Cl removal from the boiler's fuel or from its stack gases is a part of the following NO_X BACT discussions.

2.1. Identification of Possible NO_X Control Alternatives

There are two general types of options available for controlling NO_X emissions from combustion sources:

Option 1: Combustion controls that reduce NO_X formation.

Option 2: Utilizing add-on control devices to eliminate NO_X after it is formed but before it is exhausted to the atmosphere.

A special consideration is the need to avoid Cl emissions if ammonia is present. Reduction of Cl input to the boiler and combustion controls are discussed in the following paragraphs. Utilization of add-on control devices to reduce the Cl content of emissions from the boilers is discussed in Section 2.4.2.2.

Combustion controls reduce NO_X emissions by controlling the combustion temperature and the availability of oxygen. Combustion air containing both nitrogen and oxygen can combine in a high temperature environment to form thermal NO_X. The oxidation of nitrogen that is chemically bound in fuel sources can also form what is called fuel-bound NO_X. Add-on controls reduce NO_X emissions after the boiler.

As part of the original PSD Application, the Tacoma Mill submitted a "top-down" NO_X BACT analysis for the No. 7 Power Boiler. For the Amendment 1 application, the Mill re-evaluated each step of the "top-down" BACT method. Based on this new research and other engineering experience, it proposed that the control technologies evaluated in the original PSD application and the conclusions in the original BACT analysis are still valid. The technologies evaluated were:

- EMx™
- Regenerative Selective Catalytic Reduction (RSCR)
- Selective Catalytic Reduction (SCR)
- Selective Non-catalytic Reduction (SNCR)
- Dry Low NO_X (DLN) burners
- Methane $DeNO_X$
- Flue Gas Recirculation (FGR)
- OFA system with proper combustion (existing control technology)

In EMx™ (formerly called $SCONO_X$™), NO_X in the exhaust stream reacts with potassium carbonate (K_2CO_3) to form potassium nitrate (KNO_3). This compound is reacted with hydrogen to form gaseous nitrogen (N_2), and regenerate the K_2CO_3. The lower exhaust temperature limit required for the reactions in the EMxTM to take place is less than that of SCR (300ºF as opposed to 450ºF). The EMxTM system is also said to provide reductions in CO and VOC emissions by oxidation.

Systems called "regenerative" SCR (RSCR), that use heat-storing ceramic media derived from catalytic oxidation technology to reduce the amount of natural gas required to reheat the exhaust, have been developed recently that reduce fuel costs. They are located after the particulate control device because they work best on a clean gas stream.

SCR and SNCR systems are technologies for controlling NO_X emissions from combustion sources. In the SNCR process, a nitrogen compound reducing agent (generally ammonia in some form such as urea, aqueous ammonia, or anhydrous ammonia) is mixed with the exhaust from the combustion device, generally in the furnace or at the furnace exit. The NO_X reacts with the ammonia to form nitrogen and water. SNCR must operate between 1,550 to 2,100ºF. Typical NO_X reduction efficiencies of an SNCR system is in the range of 25 to 50 percent, with an ammonia slip (unreacted ammonia in the stack gas) ranging from 10 to 50 parts per million (ppm).

The SCR process is similar to SNCR in that a reagent reacts with NO_X, but a catalyst matrix, or "bed" is added downstream of the furnace to aid the reaction. The catalyst used in SCR systems allows the reduction reactions to occur at lower temperatures, and more efficiently than SNCR. SCR can operate at between 300 to 1,100ºF, depending upon the catalyst. The ammonia slip is usually below 5 ppm. Most SCR systems have been installed to reduce NO_X emissions in exhaust

streams with relatively little particulate matter, like natural gas-fired boilers and turbines, but recently some have been permitted and installed on coal-fired boilers.

DLN burners control thermal NO_X formation by avoiding high temperature combustion zones and uneven oxygen distribution. This is accomplished by burner designs that carefully control the mixing of fuel and combustion air. Generally, use of a DLN burner in wood-fired boiler requires a wall-fired furnace and relatively finely pulverized biomass fuel that is burned in suspension with coal or natural gas.

In a Methane $DeNO_X$ reburn system, a fuel (preferably natural gas) and a carrier fluid (any mixture of recirculated flue gases, steam, water, and industrial grade nitrogen) are injected into the combustion chamber. This creates an oxygen deficient secondary combustion zone for reducing NO_X and decomposing other nitrogen bearing compounds. In addition, an oxidizing tertiary combustion zone is created by injecting OFA into the combustion chamber above the oxygen deficient secondary combustion zone for thorough mixing and final burnout of combustibles. The OFA is an oxidizing fluid consisting of recirculated flue gases, steam, water, or industrial grade nitrogen.

FGR recycles lower oxygen containing combustion air to displace air in the combustion zone and reduce the overall excess air level. This lowers the flame temperature of wood combustion. Lower flame temperature reduces NO_X emissions from air oxidation, but also reduces combustion efficiency and so can increase CO formation.

OFA systems are very common in wood-fired boilers. OFA systems inject additional air above the primary stoker grate combustion area to complete the combustion occurring in suspension and reduce the unburned carbon furnace carryover from the primary combustion area of the boiler. OFA is usually introduced in multiple levels with air jets sized, located, and directed to promote more uniform and complete combustion.

“Proper combustion” generally refers to control, generally computerized, of the fuel feed rate, the amount of combustion air in the furnace, and other parameters, to ensure that the boiler operates as designed. Proper combustion is the baseline control on hog fuel boilers. It is being continuously improved through better designs of elements such as the boiler firebox shape, feed system, combustion airflow, and computer controls.

2.2. Eliminate Technically Infeasible Options

Because the proposed design specifications and operation of the boiler have not changed, the technological feasibility analysis performed in the original application is still applicable. An updated review of EPA’s RACT/BACT/LAER Clearinghouse (RBLC) database indicated that EMx™ had not been applied to any wood-fired boiler. Furthermore, the exhaust from wood combustion can degrade the performance of the EMx™ control system. Therefore, EMx™ is still considered technologically infeasible and is rejected as a BACT control alternative.

Use of a wall mounted DLN burner system would require a fundamental change of the boiler’s design away from the current spreader-stoker primary combustion system. As in the 2006 BACT

decision, a fundamental change in the boiler combustion design system cannot be required under BACT guidelines. Because of this, the DLN burner system is removed from consideration.

In the original application, the engineering consultant estimated FGR could reduce NO_X by about 10 percent, but the Tacoma Mill disputed that based on the boiler's design and low wood firing flame temperature. FGR was eliminated from consideration as BACT based on the estimated small and uncertain NO_X control effectiveness it might have with the current boiler design. That decision is still considered valid, so FGR is again removed from consideration as BACT.

2.3. Rank Remaining Control Technologies

The remaining control technologies are ranked based on control effectiveness as shown in Table 2-1. The control effectiveness presented in the original application is still applicable in terms of control efficiency. The NO_X emission rate is higher than those originally presented because of the higher baseline of 0.30 lb/MMBtu that the OFA system ended up requiring.

Table 2-1. Control Technology and Control Effectiveness

Control Technology	Predicted NO_X Emission Rate (lb/MMBtu)
RSCR	0.075
SCR	0.10
Methane $DeNO_X$	0.10
SNCR	0.10–0.12
OFA system (baseline)	0.30

2.3.1. Review of permitted control technologies

Results from the RBLC and CARB database queries for NO_X control technologies are presented in Table 2-2, sorted by permit limit, each beginning with the NO_X limit proposed for the No. 7 Power Boiler. Because of the large number of entries in the database, the tables present only a representative range of recent permit limits.

Table 2-2. NO_X Control Technology Search Results

Facility Name	Location	Permit Date	Heat Input (MMBtu/hr)	Permit Limit (lb/MMBtu)	Control Technology	Basis
WestRock Tacoma Mill	Tacoma, WA	Proposed	595	0.30	Overfire/Proper combustion	BACT-OTHER
Whitefield Power & Light	Whitefield, NH	9/10/04	220	0.33/0.075*	RSCR	OTHER
Soledad Energy	Soledad, CA	9/30/88	210	0.094/0.085†	FBC, SNCR	BACT-OTHER
South Point Power	South Point, OH	3/29/04	318	0.088	SCR	OTHER
Seattle Steam	Seattle, WA	6/23/06	100	0.1	FBC, SNCR	BACT-OTHER

Table 2-2. NO_X Control Technology Search Results

Facility Name	Location	Permit Date	Heat Input (MMBtu/hr)	Permit Limit (lb/MMBtu)	Control Technology	Basis
Multitrade LP	Hurt, VA	2/21/92	374	0.1‡	SNCR	BACT-PSD
Sierra Pacific Industries	Fredonia, WA	12/14/05	430	0.13/0.1§	SNCR	BACT-PSD
Sierra Pacific Industries	Aberdeen, WA	10/17/02	310	0.15/0.1§	SNCR	BACT-PSD
Hampton Lumber	Darrington, WA	6/1/05	245	0.15	SNCR	BACT-OTHER
Weyerhaeuser Co.	Bruce, MS	5/9/95	90	0.23	Proper combustion	BACT-PSD
Boralex Stratton	Stratton, ME	1/4/05	672	0.24/0.075¶	RSCR	BACT-OTHER
Wheelabrator Energy	Sherman Station, ME	4/9/99	315	0.25	Proper combustion	BACT-PSD
Mead Containerboard	Stevenson, AL	1/15/97	620	0.25	Proper combustion	BACT-PSD
Georgia Pacific Corp.	Gloster, MS	4/11/95	244	0.3	None	BACT-PSD
Schiller Station	Portsmouth, NH	10/25/04	720	0.6	FBC, SNCR	BACT-OTHER

∗ Daily average/quarterly average.
† Hourly average/daily average.
‡ Thirty-day rolling average.
§ Daily average/annual average.
¶ Daily average/quarterly average (quarterly limit only for Connecticut's Renewable Portfolio Standard Program, not part of air permit).

2.4. Evaluate the Most Effective Controls

The fourth of the five steps in the "top-down" BACT analysis procedure is to evaluate the most effective control and document the results. This has been performed for each remaining control technology. A technology may be eliminated based on economic, energy, or environmental impacts.

2.4.1. Environmental impacts of RSCR, SCR, and SNCR

RSCR, SCR, and SNCR all use ammonia as a reagent to reduce NO_X to N_2. The original application showed that RSCR and SCR had only been used in special situations (special grants for the RSCR installations, and unique feed and boiler conditions for the one SCR installation), and both were not in general use. Both SCR and RSCR would have a low emission rate, but as described in the initial permit application, each has technical and cost problems that make it an unattractive retrofit option for this project.

SNCR is a mature technology and has been proven to be cost-effective for installation on hog fuel boilers.

SNCR can typically reduce NO_X emissions from 5 percent to up to 64 percent depending on ammonia slip levels and boiler combustion quality issues such as uniformity of combustion

throughout the boiler and how steady the fuel feed rates are. SNCR can have an ammonia slip ranging from about 5 to 50 ppmvd or more. If the boiler burns feed with a high enough chloride content, ammonium chloride can be formed from this excess ammonia slip and emitted from the boiler stack as a highly visible bright white detached plume. The following paragraphs discuss this white plume issue.

Unreacted ammonia (ammonia slip used in conventional SNCR systems can react with sulfur and chloride compounds in the flue gas to form fine particulate matter (ammonium chloride, sulfate, or nitrate particulates) which may lead to a highly visible white plume as well as being partially absorbed into fly ash. Ammonia itself is also a toxic air pollutant subject to regulation under WAC 173-460.

Detached ammonium chloride (NH_4Cl) plumes are a particular problem for boilers that burn salt-laden wood (wood that is ocean transported via log booms or wood from coastal forests) because of the relatively high chloride content of the wood. The chloride content of salt-laden wood can be in the range of 0.8 percent whereas non-salted wood typically has chloride content less than 0.01 percent.[8]

An ammonium chloride plume can form when ammonia (NH_3) combines with HCl present in the exhaust gas under the following reaction:

$$NH_3 \text{ (gas)} + HCl \text{ (gas)} \Rightarrow NH_4Cl \text{ (white solid particulate fume)}$$

The amount formed depends on the concentrations of NH_4Cl in the exiting gas and how quickly the plume is diluted. Dilution reduces the temperature of the plume allowing the NH_4Cl to sublime. However, dilution could also reduce the concentration of NH_4Cl within the plume to the point that it is no longer visible. A critical point is reached when the plume is cooled enough to reach the point of solid formation at approximately 212ºF, if concentrations of NH_4Cl are still high enough for a visible plume.

Excessive ammonia slip occurs when complete consumption of the SNCR reagent (ammonia) is not achieved in the boiler's combustion zone. Ammonia slip can vary from five to up to more than 50 ppm depending on the boiler design (residence time, temperature, uniformity of combustion), boiler operation (variable compared to stable steam demand and fuel feed rates), fuel variability, and desired control efficiency. Ammonia slip tends to be higher for an SNCR retrofit because the boiler is not originally designed with ammonia injection as a retrofit option. Ammonia injection is effective over a relatively narrow temperature range, 1,600–2,000°F. No. 7 Power Boiler is generally within this range but, as with most Stoker-type biomass fired boilers, has variation of combustion conditions across the fire box.

Ammonia injection works best with constant boiler operating conditions. The fuel combusted in No. 7 Power Boiler is a mixture of biomass (e.g., hog fuel, wastewater sludge, urban wood and chip fines) that varies in size (from sawdust up to 6-inch pieces), moisture content, and heat content (see Table 2-3 below).

[8] "Emissions from Wood-Fired Combustion Equipment," British Columbia Ministry of Environment, June 30, 2008.

Table 2-3. Fuel Quality					
Parameter	**Units**	**Minimum**	**Maximum**	**Mean**	**Standard Deviation**
Heat Input	Btu/lb	6,620	10,600	8,199	513
Moisture	%	36	62.2	52.1	4.6

Table 2-4. Moisture Content Parameters for Fuels Used, 2011–2012					
	Amount Used (BDT/yr)		**Moisture Content (%)**		
Fuel Type	**2012**	**2011**	**Mean**	**Maximum**	**Standard Deviation**
Purchased biomass (hog fuel)	151,463	161,871	44.65	66.20	14.99

Table 2-5. Wood, 2011–2012			
	Moisture Content (%)		
Fuel Type	**Mean**	**Maximum**	**Standard Deviation**
Urban wood	39.97	57.00	14.06
Non-urban wood	49.33	66.20	14.78

Table 2-6. Moisture Content of Purchased Fuel, 2005–2012				
		Moisture Content (%)		
Fuel Type	**Year**	**Mean**	**Maximum**	**Standard Deviation**
Purchased biomass (hog fuel)	2005	37.58	62.20	17.29
	2006	31.56	48.70	7.87
	2007	33.85	40.20	9.68
	2008	---	---	---
	2009	---	---	---
	2010	45.84	63.10	10.31
	2011	40.69	63.60	18.08
	2012	47.47	66.20	12.01

Although the boiler is base-loaded by the steam turbine (the turbine provides a consistent steam demand), the variation in fuel quality causes the furnace temperature to change considerably at the NH_3 injection point. Periodic “cold spots” due to low heating value fuel would lead to “puffs” of

NH_3 slippage. The NO_X formation rate is in a constant state of flux because of the fuel variability making it difficult to determine the proper ammonia injection rate.

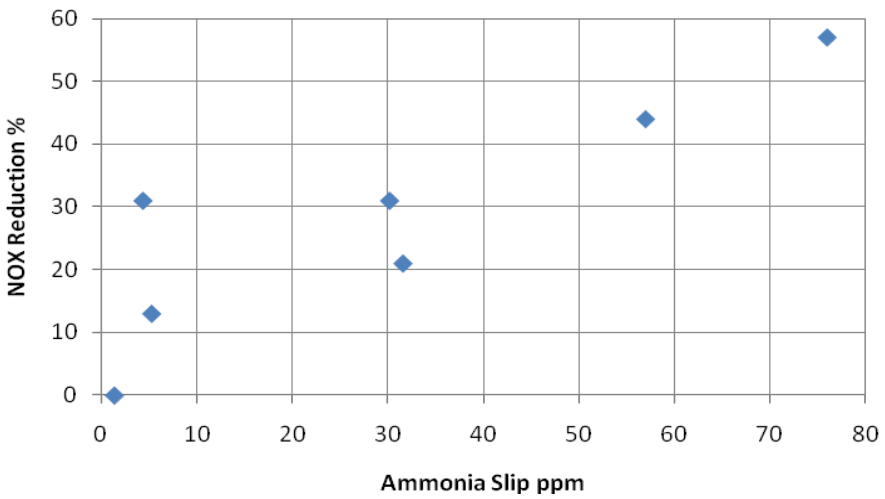
In order to achieve a high level of control efficiency, a high level of ammonia injection is required, increasing the potential for ammonia slip. For the No. 7 Power Boiler, Jansen Engineering provided an estimate of 20 percent control with an ammonia slip of 5 ppm and 45 percent control with an ammonia slip of 30 ppm for the 2006 Cogen Project PSD application. These estimates were not guaranteed by the control vendor. Updated numbers were provided by Fuel Tech, Inc. based on the higher NO_X baseline of 0.30 lb/MMBtu. Fuel Tech estimates the maximum control achievable while limiting ammonia slip to 5 ppm is 25 percent. The highest level of control the system could achieve is 64 percent, but the ammonia slip is 40 ppm at that level of control. Again, these are not firm guarantees.

Experience at the Kimberly-Clark pulp mill in Everett, Washington, (now permanently shut down) shows that ammonia slip may be much higher. Test data from KC's boiler showed ammonia slip much higher than anticipated was needed to approach the NO_X emissions design level (See Table 2-7 and Figure 2-1). The results from KC's boiler are relevant to the No. 7 Power Boiler because they are of similar design (Stoker type boilers) and age. Ammonia injection and slip was considerably higher than expected when trying to approach the permitted NO_X reduction rate. The desired NO_X reduction rate was never achieved at full load due to the detached white plume problem. Looking at the ammonia slip vs. NO_X reduction on Figure 2-1, it is likely that the ammonia slip would be at least 10 ppm and it could be as much as 30 ppm to achieve a NO_X reduction of 20 percent. At 45 percent control, ammonia slip may be 57 ppm.

Table 2-7. Kimberly-Clark Ammonia Slip

Test Date	Test Condition	Ammonia Addition (lb/hr)	Ammonia Slip (ppm)	NO_X Concentration (ppm)	NO_X % Reduction
Sept. 26-27, 1996	1	0	1.4	134	0
	2	194	4.4	88	31
	3	416	57	67	44
	4	647	76	57	57
Nov. 18-19, 1996	1	203	5.3	100	13
	2	353	30.2	84	31
	3	404	31.6	101	21

Figure 2-1. Kimberly-Clark NO_X Reduction vs. Ammonia Slip



Chloride (Cl) is the second component needed to form ammonium chloride. HCl is formed from the chloride content of the boiler's fuel when it is burned, and this makes Cl^- available to react with the ammonia slip. The chloride content in the Tacoma Mill's biomass is higher because it contains wood from high alkali soils or coastal forests, and logs transported on salt water.

In addition, the Mill uses seawater for direct cooling of its Kraft process effluent before it is sent to the plant's activated sludge water treatment process. To reduce fresh water usage (per request from the city of Tacoma), salt water pumped directly from Commencement Bay is used rather than fresh water from the City of Tacoma. This adds a salt load that ends up in the secondary treatment sludge. This sludge is dewatered and burned in No. 7 Power Boiler. Data supplied for the original permit showed that chloride in the Tacoma Mill's biomass fuel (mixture) ranges from 35 to 5,630 ppm and has an average chloride content of 1,109 (or 0.11 percent). Much of the chloride in the fuel mixture comes from the salt-laden wood and sludge. Table 2-8 below compares the chloride concentration of fuel analyses conducted by WestRock, two other local mills (Kimberly-Clark and Sierra Pacific Burlington) and the National Council of Air and Stream Improvement (a technical organization for the pulp and paper industry).

Table 2-8. Chloride Concentration in Fuel mg/kg (ppm)

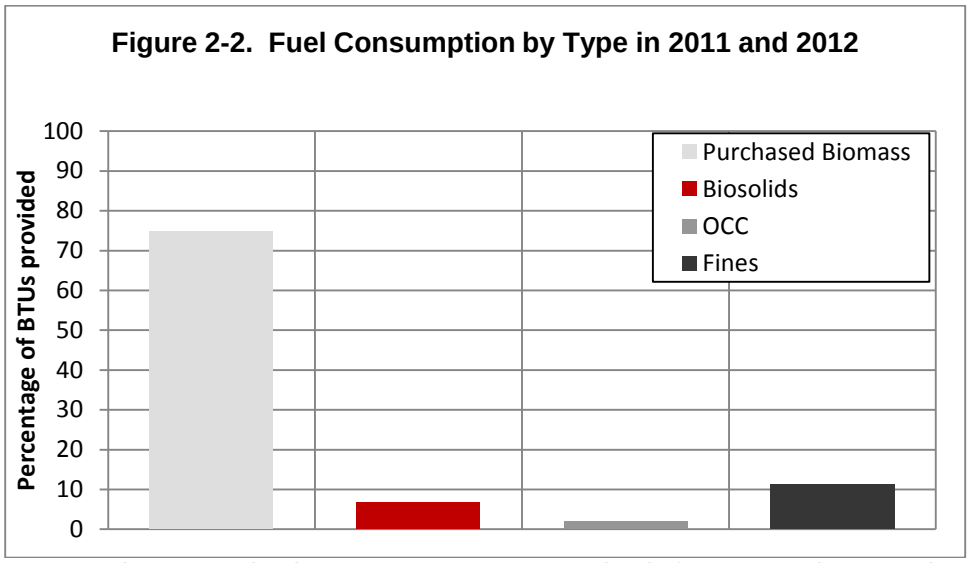
Source	Minimum	Maximum	Mean	Standard Deviation
NCASI Bark	<40	273	90	---
NCASI Stemwood*	50	91	62.4	---
WestRock Fuel Mixture†	35	5,630	1,109	780

Table 2-8. Chloride Concentration in Fuel mg/kg (ppm)				
Source	**Minimum**	**Maximum**	**Mean**	**Standard Deviation**
Kimberly-Clark				
Woodwaste fuel	500	700	570	113
Hog fuel	680	2,000	1,229	1,200
Sludge	370	960	516	420
Multiclone	910	3,500	1,991	2,000
Sierra Pacific fuel mixture	1,540	2,930	2,417	---
∗ Reference NCASI tech bulletin.				
† From 75 samples tested between March 2005 and December 2006.				

As shown in Table 2-8, local chloride concentrations are higher than the national average as represented by the NCASI surveys. The Tacoma Mill's biomass chloride content is similar to those obtained from other sources in Washington where ammonium chloride plume formation has been a problem. It is fair to assume almost all of the chloride in the fuel is converted to HCl based on source test data.

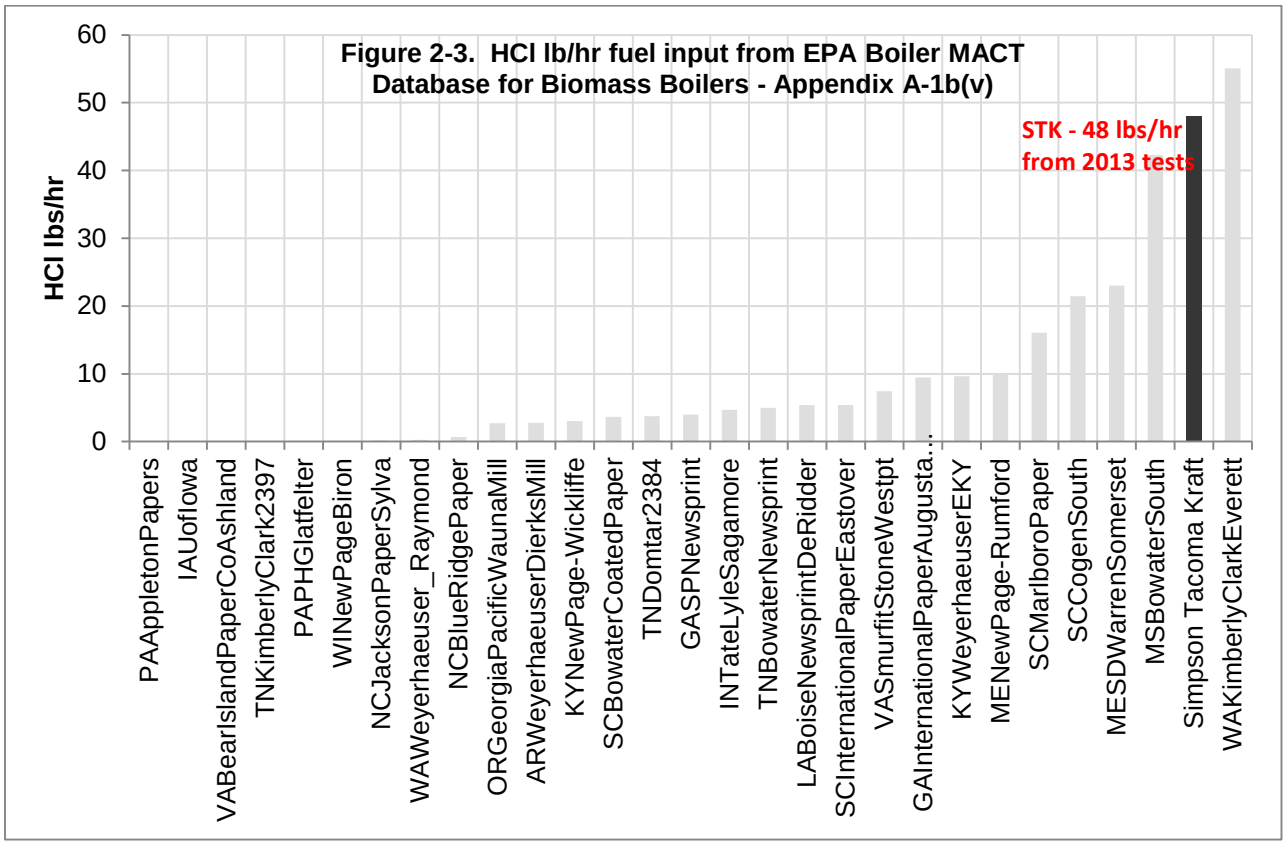
Additional data regarding the chlorine content of the Tacoma Mill's fuel has been obtained since the original PSD permit was issued. Table 2-9 below summarizes the maximum, average, and standard deviation of chloride fuel content for the different types of fuels used in No. 7 Power Boiler. The sample data comprises laboratory tests from 2005 to 2013. The graph below it illustrates the percentage of fuel consumed (in terms of the Btu) by No. 7 Power Boiler in 2011 and 2012. The percentages do not add to 100 percent as about five percent of the BTUs consumed in 2011 and 2012 were provided by natural gas, which is not shown in these graphs.

Table 2-9. Average and Maximum Chloride Content by Fuel Type			
	Chloride Content (lb/MMBtu)		
Fuel Type	**Average**	**Maximum**	**Standard Deviation**
Purchased biomass	0.14	4.66	0.51
Dewatered wastewater residuals	0.15	1.41	0.19
Paper recycling residuals (old corrugated container rejects (OCC))	0.16	0.67	0.27
Fines	0.08	0.14	0.04
Note: Average and maximum chloride content (lb/MMBtu) by fuel type for laboratory tests from 2005 to 2013.			



Note: Fuel consumption by type on a percent BTU basis for 2011 and 2012. The percentages do not add up to 100% as natural gas (approximately 5%) was not shown in this graph.

A review of the data from the EPA Boiler MACT emissions database Technical Support Documents (http://www.epa.gov/ttn/atw/boiler/boilerpg.html) reveals that the Tacoma Mill (listed as Simpson Tacoma Kraft on this graph) has a uniquely high level of chlorides in its fuel as shown in Figure 2-3 Over 63 boiler fuel chloride tests (total fuel feed to the boiler, not individual fuel types) were averaged and multiplied by the average bone dry tons per hour of fuel feed to get the 48 lb/hr of chloride to the boiler, near the top for all biomass boilers in the database. Now that Kimberly-Clark of Everett is closed down, the Tacoma Mill has a higher fuel Cl content than any other active boiler listed in this EPA Boiler MACT data set due to the naturally occurring chloride levels in its wood supply.



Note: **STK placement on HCl lb/hr from EPA database**. Data source: Dec 2011 MACT Floor Analysis for Major Source Boilers and Process Heaters. Simpson's Cl emission rate of 48 lb/hr is based on 900 ppm Cl fuel input @ 26 BDTPH fuel feed.

Data from the Kimberly-Clark mill, control vendors, and boiler combustion engineers indicate a visible NH_4Cl plume can be expected when NH_3 concentrations reach about 5 ppm with high HCl concentrations. KC further tested the plume to verify that NH_4Cl particles were responsible for the opacity. The results of these tests are shown in Table 2-10.

Table 2-10. Kimberly-Clark Opacity vs. Ammonia Slip

Test Condition	Ammonia Slip (ppm)	NO_X % Reduction	Method 9 Opacity (%)
1	1.4	0	12
2	4.4	31	9
3	57	44	36
4	76	57	58

Professor John Kramlich of the Mechanical Engineering Department at the University of Washington has studied the formation of NH_4Cl plumes. He has developed a method for estimating NH_4Cl concentrations in the exhaust gas using thermochemical equilibrium calculations based on the composition of the exhaust gas and plume entrainment. In addition, he has developed equations using the Beer-Lambert Law to estimate the opacity of the plume. Given the expected exhaust concentration of 82 ppm HCl and 5 ppm NH_3, the opacity is estimated at 10 percent. At the highest ammonia slip estimated by Fuel Tech for the best NO_X reduction rate, the opacity is estimated at 60.8 percent. The currently permitted opacity limit for the No. 7 Power Boiler is 10 percent under Condition E-2 of the Title V permit.

The previous several paragraphs of this section indicate that use of SNCR to reduce NO_X emissions from the existing WestRock boiler with its existing fuel would very likely cause formation of a white plume of ammonium chloride. In the 1990s a very visible ammonium chloride plume at the Kimberly-Clark mill in Everett was only eliminated by shutting off the ammonia feed to the SNCR system and obtaining comparable NO_X reductions from other plant sources. In about 2006–2007 when a newly installed boiler at Sierra Pacific Industries Burlington (SPIB) had a similar plume, the boiler had the advantage of a newer design that even without its SNCR system operating emitted only slightly more NO_X than its permitted limit of 0.13 lb/MMBtu. A program of minimal ammonia injection (for instance NH_3 slip tested only 4 ppm) along with segregating out higher Cl feed materials (like bark) eliminated its plume.

The Tacoma Mill's boiler is an older design similar to the Kimberly-Clark boiler. Even with the Mill's extensive effort to install and tune an improved OFA system, the boiler's NO_X emission rate is well above 0.20 lb NO_X/MMBtu. This means that more ammonia would need to be fed to WestRock's boiler than at SPIB to meet a similar NO_X limit. This would cause a higher rate of ammonia slip at the WestRock facility. Also, the Cl content of the Mill's boiler fuel would need to be lower than that of SPIB at any given NO_X limit to compensate for the higher ammonia slip level present.

The Tacoma Mill did a cost analysis for installation of an SNCR system and operating it at a point where the ammonia slip rate was 5 ppm where it probably would not create a visible ammonium chloride plume. This would reduce the NO_X about 0.07 lb/MMBtu, or from 0.30 to 0.23 lb/MMBtu, and about 184.2 tpy of NO_X. The annualized cost was estimated to be $5,675 dollars per ton of NO_X removed. Cost of the source of ammonia (a urea solution) was the majority of the cost. The actual measured NO_X level measured in 2009 was 0.28 lb/MMBtu. This indicates the actual NO_X emission rate with SNCR operating at just below plume formation potential would be close to this estimate, and higher than typical limits of SNCR equipped boilers.

Ecology did an additional cost analysis to estimate what the cost-effectiveness of this same SNCR system would be if run to reduce NO_X to a more normal permitted level of 0.15 lb/MMBtu and remove about 390.9 tpy of NO_X. The annualized total operating cost was estimated to be $4,520 dollars per ton of NO_X removed, with the urea solution again the major cost. However, to operate in this manner, the ammonia slip's environmental impact would need to be eliminated. The cost to do this was not included here, but is estimated further in this document for two possible approaches: (1) significantly reduce the chloride content in the fuels, or (2) scrub the ammonium chloride from the boiler's stack gas.

2.4.2. Pre and post boiler chloride reduction options

2.4.2.1. Option 1: Discussion of reducing the chloride content of boiler fuels

The biomass supplied to the Tacoma Mill comes from many different suppliers. Most suppliers are sawmills or log chippers that remove the bark and grind it up to create the fuel. The Mill also receives building and demolition materials (called "urban wood"), and also burns screenings of the wood chips supplied to the digester for pulp production, called chip fines. The biomass fuel supply to the No. 7 Power Boiler also includes the waste treatment residuals from the Mill's waste treatment system. The previous Table 2-8, Table 2-9, and Figure 2-3 have additional chloride data.

WestRock's studies show that fuel costs would increase about $1,500,000 per year if the biomass fuels with high chloride content were eliminated and replaced with low chloride content biomass. If the wastewater treatment residuals are not burned in the No. 7 Power Boiler, it would have to be landfilled at an additional cost of $1,000,000 per year. There would also be additional cost of approximately $700,000/year associated with replacing the heating value of the sludge with biomass fuel. Therefore, the total cost of removing fuel with the highest chloride content is $3.20 million per year. When annualized, these additional costs to reduce fuel Cl content are $8,237 for the least costly case of reduction to a 0.15 lb/MMBtu limit. When added to the SNCR installation costs, the total cost is $12,758 per ton of NO_X reduced. If the lb/MMBtu NO_X limit is set higher (more achievable) such as 0.20 lb/MMBtu, the cost per pound would be proportionally larger. Ecology would not consider this to be cost-effective. Additional fuel and stack chloride testing have raised the possibility that fuel substitution might not be capable of reducing chloride content low enough to eliminate an ammonium chloride plume.

2.4.2.2. Option 2: Discussion of scrubbing ammonium chloride from boiler emissions

As mentioned earlier, to make SNCR viable at WestRock, the formation of an ammonium chloride plume must be avoided. To do this, the removal of chloride in the boiler fuel was discussed earlier and found to be not justifiable. A second option would be to control ammonium chloride formed from the boiler's emissions. The following analysis of possible HCl controls to facilitate SNCR is provided. Ecology notes that this PSD revision is tacitly independent from any possible future requirements involving HCl control, including Boiler MACT (40 CFR part 63 subpart DDDDD).

STEP 1 – Identify all potential control technologies

WestRock researched the technical feasibility of technologies to absorb or scrub ammonium chloride (NH_4Cl) formed if SNCR was installed on No. 7 Power Boiler. Three possible scrubber technologies were found:

- Dry sorbent injection (DSI) with trona (a sodium carbonate mineral)
- Spray dry absorption (SDA) with caustic
- Wet scrubbing system with caustic

Dry Sorbent Injection

In DSI systems, finely divided sodium or calcium based minerals are injected into the boiler exhaust gases upstream of a particulate matter collection device. The injected material absorbs the acid gases on the surface of the particles, the acid gases react with the calcium or sodium compounds, and the particles are collected. DSI systems are suitable for biomass boiler acid gas controls, and experience has resulted in biomass boiler DSI systems favoring the use of sodium chemicals. Both trona (sodium sesquicarbonate) and sodium bicarbonate are used as sorbents in DSI systems. Trona is the raw material mined and calcined to produce commercial sodium bicarbonate and sodium carbonate. The price of the three chemicals reflects the amount of processing done at the mine mouth, so trona is the cheapest.

Trona does not always require milling as received, although milling does allow for more efficient use of the sorbent. Addition of trona above the stoichiometric quantity is required for high acid gas removal efficiency. For this application, approximately 1,100 lb/hr of trona is assumed necessary to achieve the desired acid gas control efficiency, which will need to be collected by a particulate control device.

Spray Dry Absorption

In SDA systems, the flue gases are introduced into an absorbing tower (dryer) where the gases are contacted with a finely atomized alkaline slurry or solution (usually a calcium-based sorbent such as $Ca(OH)_2$ or CaO, or a sodium-based chemical such as NaOH). Acid gases are absorbed by the slurry mixture, and react to form solid salts. The heat of the flue gas is used to evaporate all the water droplets leaving a non-saturated (i.e., dry) flue gas exiting the absorber tower. The effect of cooling and humidifying the hot gas stream increases collection efficiency over simple dry injection. Ample reaction sites and time must be present in the tower, and the solid reaction products must be removed from the gas stream through use of a particulate control device. Typical reaction vessels for an application like No. 7 Power Boiler are 18 feet in diameter and 65 feet high, providing 5-10 seconds of residence time.

Spray dryer absorbers are effective at removing acid gases, but do have disadvantages. The injection and atomization equipment required is much more complicated and expensive to operate than DSI. As with DSI systems, the actual use of sorbent necessary for high acid gas removal will be above the stoichiometric quantities because of normal inefficiencies in operation.

Wet Scrubbing

Wet scrubbers follow one of several design principles: packed towers, plate or tray columns, venturi scrubbers, and spray chambers.

Packed towers are columns filled with packing materials that provide a large surface area to facilitate contact between the liquid and gas. Packed tower scrubbers can achieve higher removal efficiencies, handle higher liquid rates, and have relatively lower water consumption requirements than other types of gas scrubbers. However, they may also have high system pressure drops, high

clogging and fouling potential, and extensive maintenance costs due to the presence of packing materials.

Plate or tray towers are vertical cylinders in which the liquid and gas are contacted in a stepwise fashion on trays or plates. Plate towers are easier to clean and tend to handle large temperature fluctuations better than packed towers. However, at high gas flow rates, plate towers exhibit larger pressure drops and have larger liquid holdups.

Venturi scrubbers have been generally applied for controlling particulate matter and sulfur dioxide. A venturi scrubber employs a gradually converging and then diverging section, called the throat, to clean incoming gaseous streams. Liquid is either introduced to the venturi upstream of the throat or injected directly into the throat where it is atomized by the gaseous stream. Once the liquid is atomized, particles in the exhaust gas are collected and gaseous pollutants may be absorbed. The droplets are usually removed in a centrifugal separator followed by a demister. Venturi scrubbers tend to have a high pressure drop resulting in high energy use and the relatively short gas-liquid contact time restricts their application to highly soluble gases.

Spray towers operate by delivering liquid droplets through a spray distribution system. The droplets fall through a countercurrent gas stream under the influence of gravity and contact the pollutants in the gas. Spray towers are simple to operate and maintain, and have relatively low energy requirements. However, they have the least effective mass transfer capability of the scrubbers discussed and are usually restricted to particulate matter removal and control of highly soluble gases. They also require higher water recirculation rates.

Any wet scrubber installed on the No. 7 Power Boiler would be downstream of the existing ESP. All scrubber systems would have some type of circulating water system that would have to be operated within a given pH range, along with an upper limit on the suspended solids concentration. There would be a “blow-down” stream with a solids content that would need to be managed as well.

<u>Impact on Current Particulate Matter Controls (The existing dry ESP)</u>

The No. 7 Power Boiler is currently equipped with a dry electrostatic precipitator (ESP). Because of the high level of HCl abatement necessary to avoid a visible plume from the boiler, both the DSI and SDA control options would require large quantities of reagent and would substantially increase particulate loading to the ESP. This would compel either installation of additional particulate control on the No. 7 Power Boiler (such as a baghouse) or an upgrade of the existing ESP to handle the substantial increase in particulate loading. Due to the number of variables affecting loading and collection, it is difficult to predict the extent of upgrades to the ESP that would be necessary to handle increased particulate loading from a DSI system controlling HCl to the necessary levels.

ESP upgrade scenarios are not provided for SDA because SDA does not improve the collectability of the PM formed, and SDA can cause a wet flue gas. These factors make a dry ESP nearly incompatible with SDA which would be located before it. In addition, SDA is more expensive than DSI, so DSI presents a more conservative cost (the lowest $/ton result).

The ESP upgrade cost estimate assumes that only straightforward mechanical and electrical system upgrades would be necessary to allow the ESP to handle the additional loading and maintain compliance with existing particulate emission limits. If the ESP did require an expansion or other extraordinary mechanical or electrical modifications, the cost would significantly increase.

Additional Particulate Matter Control for Wet Scrubber System

Although a wet scrubber system would be able to control acid gases from The No. 7 Power Boiler, it is unknown whether a wet scrubber would provide the level of HCl abatement necessary in this specific case to avoid formation of an unacceptable visible plume and significant $PM_{2.5}$ emissions.[9] The quenching effect of the scrubber would, in all likelihood, cool the flue gas enough to form a significant amount of NH_4Cl before the scrubber system has the opportunity to absorb NH_3 and HCl as gases rather than after they combine to form a particulate. Because scrubber technology is not very effective at collecting fine particulate, the NH_4Cl would pass through the scrubber and produce particulate emissions and a visible plume. The pressure drop required by a wet scrubber for control of sub-micron size particles is too high to be practical. In order to remove these particles, the wet scrubber system would need to be followed by a Wet Electrostatic Precipitator (WESP). Therefore, a wet scrubber with a WESP is a cost scenario evaluated in this analysis.

STEP 2 – Eliminate technically infeasible options

Although the above control options have not been demonstrated in practice in an application with chloride levels comparable to those at the Tacoma Mill concurrent with normal ammonia slip from SNCR, the control options are assumed to be technologically feasible for this analysis.[10]

STEP 3 – Rank remaining control technologies

The technologically feasible control options to be installed along with SNCR are provided in Table 2-11, along with associated emission reduction potentials.

Table 2-11. Control Technology and Control Effectiveness

Control Technology	HC1 Removal Efficiency (%)
SNCR + DSI + baghouse	90%+
SNCR + DSI + upgraded ESP	90%+
SNCR + SDA + baghouse	90%+
SNCR + wet scrubber + WESP	90%+

[9] Ammonia and chloride in flue gas form NH_4Cl at lower temperatures (~ <250°F). As temperature drops across the scrubber, there may be significant solids formation prior to adequate capture of chloride (or ammonia).

[10] Based on the proposal from Fuel Tech on July 30, 2010, as well as an evaluation of control technology by AMEC on July 23, 2014, it is assumed that this series of control technology is technically feasible. However, until trials and computational fluid dynamics (CFD) modeling can be performed, there is much uncertainty related to the injection points of ammonia and sorbent, the quantity of sorbent required, and the fluctuating temperatures and CO levels of the boiler (which will affect NO_X reduction efficiency). Additionally, trials would need to be conducted with trona injection to determine the ability of the ESP to handle the substantial increase in particulate loading. Due to these uncertainties, it cannot be stated with complete confidence that the series of control technologies presented is technically feasible.

Note that these combinations of controls must be able to achieve: (1) adequate control of NO_X emissions, (2) adequate control of chloride emissions, (3) maintain compliance with particulate matter emission limits, and (4) minimize emissions of NH_4Cl and avoid the formation of an NH_4Cl plume.

STEP 4 – Evaluate the most effective controls

The economic and environmental impact of the technologically feasible control options are discussed below.

Environmental impacts

Due to the high chloride levels in the flue gas of the No. 7 Power Boiler, the inevitable presence of ammonia slip generated from add-on NO_X control, and the impossibility of 100 percent reaction and collection rates, some additional NH_4Cl $PM_{2.5}$ would be emitted and would impact regional air quality if add-on NO_X control is utilized.

The wet scrubber/WESP option presents contaminated wastewater flow and solids. The DSI and SDA options present additional ash volume.

Energy and other impacts

Additional energy consumption would result from operation of each of the control options presented. DSI would require blowers to convey the dry sorbent and a mill would likely be necessary to prepare the material for injection. SDA and a wet scrubber/WESP each require pumping of the liquid scrubbing medium, and would require additional water use. The additional PM load to an upgraded ESP would result in higher energy use. An additional fan must be installed and operated in the case of a baghouse or a wet scrubber/WESP.

Cost-effectiveness of SNCR plus add on controls options

SNCR in combination with each of the HCl control options listed above has been evaluated for cost-effectiveness. The baseline NO_X emission rate is selected as 0.30 lb/MMBtu (the emission limit proposed in the amendment application). Baseline annual NO_X emissions, using the 0.30 lb/MMBtu rate, are estimated at 782 tpy.

Based on the information provided by Fuel Tech, SNCR with a 5 ppm ammonia slip can achieve a NO_X emission rate of 0.23 lb/MMBtu (but this performance was not guaranteed). It is estimated that the current NO_X emission limit of 0.20 lb/MMBtu can be achieved with an ammonia slip between 5 and 20 ppm. Reducing NO_X emissions from 0.30 lb/MMBtu to 0.20 lb/MMBtu would result in a NO_X reduction of 260.6 tpy.

A summary of capital costs for the three control options, which were prepared by AMEC on July 23, 2014, are summarized in Table 2-12.

Table 2-12. Capital Cost Summary				
Control Options		Total Equipment Costs	Direct Installation Costs	Indirect Installation Costs
1	SNCR + DSI + baghouse	$7,500,000	$9,000,000	$5,500,000
	SNCR + DSI + upgraded ESP	$5,000,000	$5,000,000	$5,000,000
2	SNCR + SDA + baghouse	$10,000,000	$12,000,000	$10,000,000
3	SNCR + wet scrubber + WESP	$8,500,000	$9,580,000	$9,000,000

Using the baseline of 0.30 lb/MMBtu NO_X, the costs of control options capable of achieving a NO_X emission rate of 0.20 lb/MMBtu are provided in Table 2-12. Note that these costs are conservative estimations because the analysis did not account for the costs associated with on-site demolition, retrofitting of equipment, and the additional footprint required for the proposed control options. The dollars per ton removed costs presented in Tables 2-13 and 2-14 are significantly above that which would be considered cost-effective. Therefore, the above control options are not considered economically feasible.

Table 2-13. Summary of Chloride Removal from Fuel Cost-Effectiveness (Option 1)	
Control Options (Option 1)	Cost-Effectiveness $/Ton of NO_X Control 0.30 to 0.23 lb/MMBtu NO_X Reduction
SNCR + switch to low chloride biofuels + landfill wastewater treatment residuals + replace BTU value of sludge	$23,077

To make a simple evaluation of the cost-effectiveness of reducing NO_X further to a value closer to normal new boiler permitting, Ecology simply scaled the above analysis to a NO_X reduction of 0.30 to 0.15 lb/MMBtu. The cost-effectiveness became $12,758 per ton of NO_X controlled, which Ecology considers to be unacceptable. It is also suspect whether this could be done without having an ammonia slip much greater than 5 ppm, use of more ammonia than assumed, and formation of a visible ammonium chloride plume.

Table 2-14. Summary of Add-On Controls Cost-Effectiveness (Option 2)		
Control Options (Option 2)		Cost-Effectiveness ($/Ton of NO_X Control)
1	SNCR + DSI + baghouse	$20,300
	SNCR + DSI + upgraded ESP	$16,300
2	SNCR + SDA + baghouse	$24,100
3	SNCR + wet scrubber + WESP	$20,300

Discussion of Ammonium Chloride Emissions as a Direct $PM_{2.5}$ Emission:

If an ammonia based control technology was applied to this boiler, the ammonia slip emission was evaluated for its potential to form a direct emission of $PM_{2.5}$ as NH_4Cl. At a 5 ppmdv ammonia slip rate (the emission rate low enough to where a plume should not be visible), and assuming that all of the ammonia was converted to ammonium chloride, an emission of about 140 lb/day or 25.7 tpy of $PM_{2.5}$ would be expected at the stack conditions of a recent compliance test in December 2009. This same test indicated an emission of 19.8 tpy of filterable PM_{10} was being emitted. This indicates that SNCR operation at 5 ppmdv NH_3 slip could more than double the Tacoma Mill's fine particulate emissions.

Discussion of NO_X as a $PM_{2.5}$ Precursor

The Tacoma Mill's physical plant location was recently determined to be a $PM_{2.5}$ attainment area.[11] Woodstove emissions during cold winter weather are the overwhelming primary source of the $PM_{2.5}$, but industrial source emissions also contribute slightly.[12] EPA Region 10 has advised Ecology that at the current time, modeling for $PM_{2.5}$ precursor impacts is not required as stated in the preamble to the final federal $PM_{2.5}$ rulemaking.[13]

2.4.3. Cost-effectiveness

In the original BACT analysis, Methane $DeNO_X$ was determined to be cost ineffective. With an increase in the NO_X emission baseline, this control technology has been revisited to see if it is has become cost-effective. Jansen estimated 50 percent removal efficiency for Methane $DeNO_X$ at the time of the original BACT analysis. Using the new proposed baseline of 0.30 lb/MMBtu, the updated cost-effectiveness is $17,037 per ton of NO_X removed, which the Tacoma Mill has shown to be outside the envelope of acceptable costs.[14]

The cost-effectiveness of RSCR, SCR, and SNCR were compared in the original application, and reviewed in this amendment application. SNCR was found to be well proven as a NO_X BACT control technology, but when the additional costs of the fuel and process changes needed were included to allow NO_X reduction to 0.23 lb/MMBtu, Table 2-13 shows that the annualized cost of SNCR was estimated to be $23,077 per ton of NO_X removed. If the target NO_X reduction concentration is 0.15 lb/MMBtu, the cost per ton of NO_X removed is $12,758. This second case comes with a probability of higher than 5 ppm ammonia slip and the potential for the creation of a visible plume of ammonium chloride.

The cost-effectiveness of SNCR combined with add-on controls to remove chloride and ammonia from the boiler emissions were investigated. Add-on controls included DSI + baghouse, DSI +

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[11] Federal Register/Vol. 80, No. 27/Tuesday, February 10, 2015/Rules and Regulations, p. 7347.
[12] "Sources of Fine Particles in the Wapato Hills-Puyallup River Valley $PM_{2.5}$ Nonattainment Area," Ecology Publication No. 10-02-009 available at http://www.ecy.wa.gov/pubs/1002009.pdf.
[13] E-mail from Nancy Helm and Herman Wong to Jeff Johnston on January 7, 2010.
[14] This assumes that capital and operating costs have not decreased or increased significantly since 2006 for this type of control technology.

upgraded ESP, SDA + baghouse, and a wet scrubber + WESP. Table 2-14 shows that cost-effectiveness ranged from $16,300 to $24,100 per ton of NO_X removed.

2.4.4. Selection of BACT for NO_X

Ecology has reviewed the BACT options available for control of NO_X emissions and removal of chloride (Cl) and ammonia from the Tacoma Mill's No. 7 Power Boiler. SNCR was the only control technology that was proven to reduce NO_X emissions and be cost-effective to install and operate. However, a case-by-case analysis of the environmental impacts of installing SNCR shows that there would be a high probability of generating a visible white plume of ammonium chloride particles if SNCR were to be installed on the No. 7 Power Boiler. Specifically, the high, naturally occurring Cl content of the boiler's current biomass fuel reacting with the SNCRs ammonia slip would be the cause. A plume like this has been formed previously at two Washington mills, and was highly objectionable to their local communities.

The option of using SNCR with select changes in fuel mix to reduce chloride content to a level that would not create a visible NH_4Cl plume as shown in Table 2-13 was found to be possible, but would increase the SNCRs cost-effectiveness between $12,758 and $23,077 per ton, depending on the lb/MMBtu control level selected. Ecology finds this option is not cost-effective.

The option of using SNCR along with four different configurations of add-on controls capable of removing chloride and ammonia down to a level that would not create a visible NH_4Cl plume as shown in Table 2-14 was found to be possible, but the ability of these technologies to consistently perform at the high efficiency required was questioned. Further, the cost-effectiveness of these four options ranged from $16,300 to $24,100 per ton of NO_X removed; therefore, Ecology finds these options are not cost-effective.

With any of the options involving the installation of SNCR, the formation of ammonium chloride would result in direct emissions of fine particulate as well as a visibility problem. At the 5 ppm ammonia slip level that would probably have an acceptable visibility impact, the NH_4Cl fine particulate emission rate would be greater than the fine particulate currently emitted as measured by a recent boiler compliance test. NO_X is also a precursor to particulates, but NO_X reacts to form a particulate over a period of time after leaving the stack, as opposed to the essentially immediate formation of NH_4Cl when it cools after leaving the boiler stack. Modeling of this secondary impact is not currently required by EPA Region 10 because of several regulatory and technical reasons.[15]

For all these reasons, WestRock proposes and Ecology agrees that BACT for NO_X emissions from No. 7 Power Boiler is 0.30 lb/MMBtu, based on using proper combustion controls and OFA. SNCR, although effective at reducing NO_X emissions, is not acceptable when the environmental trade-offs, operating complications, and costs are considered. A case-by-case analysis determined that unique considerations at the Tacoma Mill create a high risk of producing a persistent, visible plume of ammonium chloride particles from the stack if SNCR were installed on the No. 7 Power Boiler. The options of either changing the Mill's fuel mix to lower its chloride content or use of post-boiler add-on control processes to remove chloride make SNCR not cost-effective.

[15]Federal Register, Vol. 70, No. 216, Wednesday, November 9, 2005. Rules and Regulations, pp. 68218–68261.

3. AIR QUALITY IMPACTS ANALYSIS

The PSD permitting program requires that an Ambient Air Quality Impacts Analysis (AQIA) be made for pollutants emitted in significant quantities. The AQIA determines if emissions of any pollutant will cause or contribute to an exceedance of a National Ambient Air Quality Standard (NAAQS). It also determines if the change in air quality since the applicable baseline dates is greater than the Class I and Class II PSD Increment Levels.

An AQIA can include up to three parts: Significant Impact analysis, NAAQS analysis, and PSD Increment analysis. The first step in the AQIA is to determine if emissions from a proposed project result in impacts greater than the modeling significant impact levels (SILs). Then, for those pollutants and averaging periods that have impacts greater than their SIL, a full impacts NAAQS analysis is used to determine if a proposed project will cause or contribute to an exceedance of a NAAQS. A PSD Increment analysis for those pollutants is also used to determine if the change in the air quality since the applicable baseline dates is greater than the Class I and Class II PSD Increment Levels. An ozone impacts analysis is required if the increase in an ozone precursor (NO_X or VOC) is greater than 100 tpy.

For the current permitting action, a new dispersion modeling analysis was necessary to ensure that the new NO_X limits (the only pollutant open for this amendment) did not cause or contribute to a violation of the NAAQS or PSD Increment standards. The total NO_X increase for the project (difference between the original project's baseline actual emissions and the new proposed 0.30 lb/MMBtu limit, not just the increase for this amendment) was modeled. The new dispersion modeling analysis for NO_X was completed using the same modeling methodology outlined in the original Cogen Project PSD application, submitted on September 5, 2006. This analysis is provided as Appendix C to the permit amendment application.

The following sections will discuss the AQIA of the nearby Class II area. The AQIA for the Class I areas will be discussed along with the Air Quality Related Values (AQRVs) in Chapter 4.

3.1. Model Selection and Procedures

The terrain in the immediate vicinity of the WestRock facility is relatively flat; however, terrain with elevations at and above boiler plume heights exists in downtown Tacoma and on Indian Hill about four kilometers (km) north of the facility. The No. 7 Power Boiler stack and cooling tower are also close to large structures and are not sufficiently high to escape the influence of building downwash on dispersion from these point sources. The dispersion model selected for the analysis needs to consider both complex terrain and building downwash effects.

AERMOD was selected for modeling simulations of the Project. EPA established AERMOD as the preferred air dispersion model in the agency's "Guideline on Air Quality Models" (Appendix W) in place of the ISCST3 air dispersion model.[16] AERMOD has more realistic dispersion algorithms to examine potential impacts to receptors in complex terrain and caused by building downwash effects.

[16] Ibid.

3.2. Dispersion Modeling Pollutant Emission Rates

The PSD Significance Analysis only considers the net emissions increase from the change due to the project. NO_X emissions from the No. 7 Power Boiler are the only emissions affected by the PSD amendment request. The net emissions increase is the proposed potential emissions minus the baseline emissions. The 2006 PSD application identified 2000 to 2001 as the baseline year and baseline emissions of 289 tpy. Future potential emissions are estimated based on the BACT limit of 0.30 lb/MMBtu proposed in the PSD amendment and the potential heat input capacity of the boiler of 595.6 MMBtu/hr. This calculates to 782 tpy for the proposed potential emissions. Therefore, the net emission increase is 782 minus 289 or 493 tpy. Hourly NO_X emissions are annualized from this data.

3.3. Maximum NO_X Concentrations from the Project

Modeling results are shown in Table 3-1. Table 3-1 also lists SILs and monitoring *de minimus* levels for comparison with the predicted concentration. As shown, the predicted NO_X concentration due to the project exceeds the SIL for the annual averaging period. The predicted concentration is below the annual monitoring *de minimus* of 14 $\mu g/m^3$ and, therefore, the new proposed emission limits do not affect applicability of pre-construction monitoring requirements.

The concentration contour plot provided in the application showed the Significant Impact Area (SIA) with the location of the maximum predicted concentration occurring approximately 750 meters south of the No. 7 Power Boiler within the extents of the fine receptor grid. The receptors showing exceedances of SILs extend up to 7.8 km to the south of the facility to the edge of the coarse receptor grid. The coarse grid was extended to the south by two km to ensure the entire SIA was captured. No additional significant receptors are identified in the extended coarse grid.

Table 3-1. NO_2 Significant Impact Analysis Results

Avg. Period	Met Data Year	UTM East (km)	UTM North (km)	Maximum Concentration ($\mu g/m^3$)	SIA (km)	SIL ($\mu g/m^3$)	Monitoring *De Minimis* ($\mu g/m^3$)
Annual	2002	543.200	5,234.000	2.9*	7.8	1	14*

* Annual arithmetic mean.

3.4. Full Impacts Analysis

As shown in Table 3-1, project emissions (including Amendment 1) have a predicted maximum ambient concentration that exceeds the annual SIL for NO_2. Therefore, a Full Impact analysis was conducted for NO_2.

The allowable, actual, and baseline emission rates for the Tacoma Mill sources were developed, along with stack conditions needed for modeling. Allowable emissions were used for the NAAQS analysis and the 2-year average actual (2007 and 2008) and 1988 baseline emissions were used for the PSD Increment analysis. Baseline emissions are zero for any sources that did not exist in the

NO_X increment baseline year. Allowable and 2-year average actual emissions are zero for any sources that have been removed since the baseline year.

To determine nearby sources and their emissions, a list of Washington sources was provided by Ecology from their 2006 and 2007 emissions inventories. The sources were screened to determine which sources have the potential to significantly influence concentrations within the Tacoma Mill's NO_X SIA.

Actual NO_X emissions from the inventory were used for the PSD Increment analysis. As approved by Ecology, actual NO_X emissions were multiplied by three to estimate maximum (allowable) emissions of nearby sources for use in the NAAQS analysis. Baseline sources for the PSD Increment analysis were screened in the same way, using actual emissions from 1990 for minor sources and 1988 for major sources.

An ambient background concentration was added to the concentration predicted by the dispersion model for comparison with the NAAQS. NO_2 data was collected on Beacon Hill in Seattle, Washington. The measured concentration was 28 $\mu g/m^3$ on an annual average period in 2008.

The modeling analysis was based on emissions of total NO_X, which includes both NO and NO_2. NO_2 concentrations are conservatively calculated assuming 75 percent conversion of NO_X to NO_2.[17]

3.4.1. NAAQS Results

Results of the NAAQS analysis are provided in Table 3-2 below. As shown, the total predicted concentrations of NO_X from the Tacoma Mill based on the corrected permit limit, NO_X concentrations from nearby sources, plus the background NO_X concentration are below the NAAQS. The maximum predicted concentration occurs on the northeastern facility fence line. From the Tacoma Mill, the main source contributing to the maximum concentration is the No. 7 Power Boiler.

Table 3-2. NO_2 NAAQS Analysis Results

Avg. Period	Year of Maximum	UTM East (km)	UTM North (km)	Modeled Concentration* ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
Annual	2002	543,422.8	5,234,842	43.3	28	71.3	100*

∗ Annual arithmetic mean.

3.4.2. PSD Increment Results

Results of the PSD Increment analysis for NO_X are provided in Table 3-3 below. As shown, the total predicted concentration is below the PSD Increment standard. The maximum predicted concentration occurs on the northeastern facility fence line. From the Tacoma Mill, the main source contributing to the maximum concentration is the No. 7 Power Boiler.

[17] 40 CFR 51, App. W, Section 5.2.4.

Table 3-3. NO_2 PSD Increment Analysis Results				
Year of Maximum	**UTM East (km)**	**UTM North (km)**	**Modeled Concentration* (µg/m³)**	**Background (µg/m³)**
2002	543,422.8	5,234,842	22.9	25*
* Annual arithmetic mean.				

4. CLASS I AREA IMPACT ANALYSIS

Federal[18] and Washington State[19] PSD regulations require an analysis of the impact of a proposed facility on federal Class I areas. Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historic perspective and are afforded the highest level of protection under the PSD rules. They include certain national parks, national wilderness areas, and national memorial parks.

Because the Class I area impacts analysis for this current permitting activity basically repeats the original permit analysis with only the NO_X emission rate increased, it could be targeted to the Class I areas most impacted in the original project's impact analysis. The National Park Service (NPS) requested analyses of AQRV impacts for three specific Class I areas, which are listed in Table 4-1. The domain selected for the PSD analysis was based on discussions with the NPS.[20]

The distances from the facility to the three Class I areas considered in this analysis are given in Table 4-1, along with the final "Q/D" values often used by FLMs as a screening tool. The "Q" value (545 tpy) is the sum of the maximum short-term average emission rates of NO_X, SO_2, PM_{10} and H_2SO_4 in lb/hr associated with the project, extrapolated to a year of continuous operation (8,760 hr/yr) and converted to tpy.

The AQRVs of concern include visibility, soil, flora, fauna, and aquatic resources. The CALPUFF modeling system is currently recommended for evaluating impacts to AQRVs in Class I areas affected by long-range transport. Potential impacts are characterized based on predictions of total nitrogen and/or sulfur deposition flux, change in light extinction, and pollutant concentrations. Pollutant concentration predictions were also used to assess Class I area increment consumption for pollutants subject to PSD review.

Table 4-1. Class I Areas and Q/D Analysis		
Name	**Distance to Class I Area (km)**	**Q/D Value (tpy/km)**
Alpine Lakes Wilderness Area	64	8.5

[18] 40 CFR 52.21(p).
[19] WAC 173-400-117.
[20] Mr. John Notar and Mr. Dee Morse, pre-PSD meeting (conference call) for the Simpson – Shelton cogeneration unit project on February 3, 2010.

Table 4-1. Class I Areas and Q/D Analysis		
Name	**Distance to Class I Area (km)**	**Q/D Value (tpy/km)**
Mt. Rainier National Park	47	11.6
Olympic National Park	67	8.1

4.1. Model Selection and Procedures

The Guideline[21] identifies the CALPUFF modeling system as the EPA's preferred model for long-range transport assessments and for evaluating potential impacts on Class I areas. Features of the CALPUFF modeling system include the ability to consider: secondary aerosol formation; gaseous and particle deposition; wet and dry deposition processes; complex three-dimensional wind regimes, and the effects of humidity on regional visibility.

On April 15, 2003, EPA adopted the CALPUFF modeling system as the EPA's preferred model for long-range transport assessments and for evaluating potential impacts to Class I areas by including CALPUFF in Appendix A of the Guidelines. Features of the CALPUFF modeling system include the ability to consider: secondary aerosol formation; gaseous and particle deposition; wet and dry deposition processes; complex three-dimensional wind regimes; and the effects of humidity on regional visibility. As is currently required, CALPUFF Version 5.8 (release date June 23, 2007) was used.

The modeling procedures used for the Class I area analysis followed the recommendations of the Interagency Agency Workgroup on Air Quality Modeling (IWAQM) and the FLM Air Quality Related Values Workgroup (FLAG), outlined in the FLAG Phase I Report (December 2000). EPA endorsed these procedures in advance in the IWAQM Phase II report (December 1998), and reiterated this endorsement in the April 15, 2003, Federal Register notice (Volume 68, Number 72) that adopted CALPUFF as a Guideline model. EPA further clarified their required CALMET settings in a memo issued on August 31, 2009 (Fox, 2009). ENVIRON (the Tacoma Mill's modeling contractor for the Class I impacts analysis) used the procedures and defaults recommended by the FLAG Phase I Report and the EPA-FLM CALMET Clarification Memo. The presentation of the modeling impacts in this Technical Support Document reflects some of the recommendations included in FLAG 2010, which was finalized in October 2010.

For the regional haze (visibility) assessment using the CALPUFF modeling system, PM_{10} emission rates must be speciated into six fractions: soot or elemental carbon (EC), PM fine (PMF), PM coarse (PMC), organic carbon (OC), sulfate (SO_4), and nitrate (NO_3). Table 4-2 shows the speciated PM_{10} emission rates used in the analysis. The speciation was accomplished using stack test data for the No. 7 Power Boiler.

[21]EPA's Guideline on Air Quality Models is contained in 40 CFR 51 Appendix W.

To be conservative, the maximum 24-hour emission rate was used in the CALPUFF modeling for both the short- and long-term (annual) assessments.

Table 4-2. Speciated Emission Rates for AQRV Analysis

Source	SO_2 (lb/hr)	NO_X (lb/hr)	Speciated PM_{10}* (lb/hr)					
			Course Mass	Fine Sulfate (as SO_4)	Fine Nitrate (as NO_3)	Fine Elemental Carbon	Fine Organic Carbon	Fine Crustal Material
No. 7 Power Boiler†	3.40	112.7	0	4.48	0	1.0	0.07	1.87
Cooling tower, 2 cells combined‡	0	0	0	0	0	0	0	0.90

∗ PM_{10} is the sum of coarse mass and the fine PM ($PM_{2.5}$) components: ammonium sulfate, ammonium nitrate, fine crustal material, elemental carbon, and organic carbon.

† PM_{10} is assumed to be 100 percent $PM_{2.5}$. Source tests indicate 89 percent of the PM_{10} is in the condensable fraction. Subsequent analysis of this fraction indicated 76 percent was ammonium sulfate, zero percent nitrate, and one percent organic matter. The remaining condensable fraction was assumed to be generic inorganic fine mass. The filterable portion (11 percent) was conservatively assumed to be all elemental carbon.

‡ Cooling tower emissions were assumed to be 100 percent fine crustal mass.

The NO_X chemistry in CALPUFF depends on the ambient ammonia concentration to establish the equilibrium between gaseous nitric acid and ammonium nitrate. Ambient ammonia concentrations are not explicitly simulated by CALPUFF and the user must select an appropriate background concentration. The average concentration observed by Environment Canada (17 ppb) was used in the current study and is considered a conservative background ammonia concentration since the majority of the land use in the domain is forest and actual ammonia concentrations are likely lower. The 17 ppb background concentration has been used for past AQRV studies in the same region, and its use is also considered conservative because it ensures the conversion of NO_X to ammonium nitrate is not limited by a lack of ammonia for the range of NO_X concentrations predicted in this study.

Reaction rates in the CALPUFF chemistry algorithms are also influenced by background ozone concentrations. ENVIRON obtained ozone data collected concurrent with the modeled period at various NPS, Ecology, Oregon Department of Environmental Quality (ODEQ), and British Columbia Ministry of Water, Land, and Air Protection (MWLAP) stations within and around the study area. CALPUFF uses a background ozone value (BCK03) for hours when none of the supplied ozone stations have valid data. A conservative value of 60 ppb was specified, to avoid artificially limiting chemical transformations (e.g., NO_X titration). However, there are no hours with all stations reporting missing values in the given ozone dataset.

Mr. Rick Graw of the USFS requested the addition of a single ozone "pseudo-station" near the Alpine Lakes Wilderness Area.[22] The ozone concentration data collected at the monitoring station

[22] Rick Graw, USFS, to Eri Ottersburg, SLR International, e-mail message, June 11, 2010.

located at the Mt. Rainier National Park Jackson Visitor Center was used as data for a pseudo-station located near the point where the Alpine Lakes Wilderness Area is closest to the facility. The intent of this addition is to ensure that high-elevation ozone concentrations are adequately represented in the sulfate and nitrate chemical transformation calculations within the Alpine Lakes Wilderness Area.

Meteorological data sets were obtained from the UW's numerical simulations of Pacific Northwest weather with the Penn State and National Center of Atmospheric Research Mesoscale Model (MM5). The AQRV analysis used three years of hourly 4-km horizontal mesh size MM5 output data from January 2003 to December 2005.

4.2. Criteria Pollutant Concentrations

The CALPUFF modeling system was used to predict concentrations of NO_2, SO_2, and PM_{10} in regional Class I areas. Table 4-3 summarizes the predicted maximum concentrations and compares them to the Class I SILs and the Class I PSD increments. At this point, there are two sets of Class I SILs: those proposed by EPA, and those recommended by the FLMs. These proposed and recommended SILs were obtained from the Federal Register, Vol. 61, No. 143, p. 38292, July 23, 1996. As shown in Table 4-3, the CALPUFF simulations indicate neither the SILs nor the increments will be exceeded.

Table 4-3. Predicted Class I Area Criteria Pollutant Concentrations

Class I Area of Interest	Maximum Predicted Concentration ($\mu g/m^3$) NO_2* Annual Average
Alpine Lakes Wilderness Area	0.0097
Mt. Rainier National Park	0.0100
Olympic National Park	0.0052
Class I Area Maximum Concentration	0.0100
EPA proposed SIL†	0.1
FLM recommended SIL†	0.03
Class I area PSD Increment‡	2.5

∗ NO_X was conservatively assumed to be 100 percent converted to NO_2.

† SIL; EPA proposed and FLM recommended from the Federal Register, Vol. 61, No. 142, p. 38292, July 23, 1996.

‡ PSD; from 40 CFR 52.21(c), adopted by reference in WAC 173-400-720(4)(a)(v).

4.3. Nitrogen and Sulfur Deposition

CALPUFF was also used to predict the impacts of acid-forming compounds emitted by the project on soils and vegetation in regional Class I areas. The deposition analysis results are shown in Table 4-4. There are no promulgated standards for evaluation of these incremental impacts to soils and

vegetation in Washington. However, the NPS has established Deposition Analysis Thresholds (DATs) for nitrogen of 0.005 kg/ha/yr.[23] These "thresholds" are based on natural background deposition estimates culled from various research efforts, a variability factor, and a safety factor that accounts for cumulative effects. The DATs are not adverse impact thresholds, but are intended as conservative screening criteria that allow the FLMs to identify potential deposition fluxes that require their consideration on a case-by-case basis. As shown in Table 4-4., predicted maximum nitrogen deposition fluxes do not exceed the DATs.

Table 4-4. Predicted Class I Area Deposition Fluxes

Class I Area of Interest	Nitrogen Deposition (kg/ha/yr)
Alpine Lakes Wilderness Area	0.0043
Mt. Rainier National Park	0.0031
Olympic National Park	0.0017
NPS DAT	0.0050

4.4. Visibility – Regional Haze

Compliance with FLM-recommended criteria for regional visibility impacts was assessed by calculating the change in 24-hour extinction for each Class I receptor. The CALPUFF modeling system was used to predict both the extinction coefficient attributable to emissions from the project as well as the background extinction coefficients for that day's meteorology. Table 4-5 lists the highest maximum predicted change in extinction at each Class I area.

FLAG 2008 draft and FLAG 2010 final guidance suggest a comparison between the 98th percentile visibility degradation predicted using Method 8 with the five percent "just perceptible" limit. As can be seen in Table 4-5, the 1st highest (as opposed to the 98th percentile) is slightly above the five percent threshold. There is only one day in the 3-year period with over five percent change. The 98th percentile values for Mount Rainier National Park are all below the five percent "just perceptible" limit. Table 4-5 presents the Method 8, 98th percentile values for Mount Rainier NP. The percent change is below five for Olympic National Park and Alpine Lakes Wilderness Area.

The background extinction assumed is based on the EPA recommendations for "natural conditions" used to represent low aerosol concentrations and excellent visibility in Class I areas. As such, actual background extinction coefficients in most areas of the domain are considerably higher and the change to extinction would be much less. The overall maximum change in extinction predicted by Method 8 occurred on October 4, 2003, also in Mt. Rainier National Park.

[23] Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds, available on the FLAG internet site at <http://www2.nature.nps.gov/ard/flagfree/NSDATGuidance.htm>.

Table 4-5. Maximum Predicted Extinction Change by Class I Area, Method 8

Class I Area	Date	B_{ext}* (1 Mm)			Change (%)
		Project	Background†	Total	
Mt. Rainier NP‡	10/4/2003	0.927	17.946	18.873	5.16
Alpine Lakes WA	10/4/2003	0.829	17.201	18.030	4.82
Olympic NP	12/2/2005	0.800	18.558	19.358	4.31

∗ Project and background extinction values for daily period that resulted in the maximum percent change in extinction.

† Background extinction derived from default annual average extinction components provided in FLAG 2008 tables.

‡ Mt. Rainier NP had only one day during the 3-year period over five percent change (the 2nd highest change to extinction was 4.16 percent; and the highest 98th percentile change to extinction was 1.72 percent).

Table 4-6. 98th Percentile Predicted Extinction Change for Mt. Rainier NP, Method 8

Year	98th Percentile Change (%)*	
	One-Year	Three-Year
2003	1.72	1.58
2004	1.52	
2005	1.40	

∗ The 98th percentile for one year is the 8th highest daily value, and the 98th percentile for the 3-year period is the 22nd highest daily value.

As shown in Table 4-5, the maximum predicted change in extinction to a Class I area based on three years of simulation on any day of the simulation was 5.16 percent in the Mt. Rainier National Park. Table 4-6 shows that the highest 98th percentile value is 1.72 for any given year, and 1.58 for the three-year period, which is less than the five percent threshold established by the FLMs. The predicted maximum changes to extinction for the other Class I areas, CRGNSA, and Mt. Baker Wilderness are typically much lower than the criterion. Based on the FLAG screening criterion, the CALPUFF simulations suggest project emissions would not significantly degrade visibility in regional Class I areas of interest.

4.5. Conclusion Concerning AQRVs

Table 4-7 summarizes the Class I area AQRV data.

Table 4-7. Class I Area Analysis Results Summary

Class I Area	Annual Average NO_2 Concentration* ($\mu g/m^3$)		Annual Average Nitrogen Deposition (kg/ha/yr)	98th Percentile Predicted Extinction Change Method 8 (%)
Alpine Lakes WA	0.0097		0.0043	4.31†
Mt. Rainier NP	0.0100		0.0031	1.72
Olympic NP	0.0052		0.0017	4.82†
Class I area maximum	0.0100		0.0043	1.72
Standard	EPA SIL‡	0.1	0.005	5
	FLM SIL‡	0.03		
	Class I increment§	2.5		

∗ NO_X was conservatively assumed to be 100 percent converted to NO_2.
† The maximum extinction change is presented.
‡ EPA proposed and FLM recommended from the Federal Register, Vol. 61, No. 142, p. 38292, July 23, 1996.
§ 40 CFR 52.21(c), adopted by reference in WAC 173-400-720(4)(a)(v).

Ecology determines that increased emissions from the Project (including Amendment 1) are not expected to significantly impact deposition or degrade visibility in the Alpine Lakes Wilderness, the Olympic National Park, the Mount Rainier National Park, or any other Class I area. The NPS and NFS land managers were consulted concerning these impacts and did not consider them objectionable.

5. ADDITIONAL IMPACTS ANALYSIS

Under 40 CFR 52.21(o), PSD applications must provide: "an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification." In accordance with these requirements, the following analysis of additional impacts from the Project (including Amendment 1) has been prepared.

Growth Analysis: The Project (including Amendment 1) will not increase the number of employees at the Tacoma Mill. Therefore, no increase in emissions from residential growth or in commuting-related mobile source emissions will be directly related to the proposed project. The Project (including Amendment 1) is not expected to cause any construction or growth related air quality impacts at or around the Mill.

Soils and Vegetation Analysis: The Tacoma Mill is located in an area designated attainment for all criteria pollutants. NO_2 and SO_2 may affect vegetation either by direct contact with the leaf surface or by solution in water drops, becoming nitric and sulfuric acid. The net increase in emissions of NO_2 was modeled and the predicted concentrations were found acceptable. The Project (including Amendment 1) does not result in a significant increase in emissions of SO_2 either. Based on these results, the Project (including Amendment 1) should not cause any significant air quality impacts on the soil and vegetation in the area.

Visibility Impairment Analysis: The Project (including Amendment 1) is not expected to produce any perceptible visibility impacts in the vicinity of the WestRock Tacoma Mill. As long as SNCR is not required, no change in boiler exhaust opacity is expected as a result of the project, so no local visibility impairment is anticipated. The long-range visibility impacts from the proposed source on Class I areas are evaluated in Chapter 4.

6. CONCLUSION

The initial project and the current permitting action (Amendment 1 to the original PSD 06-02) will have no significant adverse impact on air quality or air quality related values. The Washington State Department of Ecology finds the applicant, WestRock Tacoma Mill, has satisfied all requirements for approval of their application to amend the existing PSD 06-02 for the Steam Turbine Generator Project.

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