

# Weyerhaeuser – Longview

## Best Available Retrofit Technology (BART)

### Response to 2-7-08 Ecology Comment Letter

1. Section 2. Emission Units and Emissions The title of this section would indicate that information about the design and operating criteria of the 3 BART eligible emission units would be found here. Similarly the actual 24-hour maximum emissions used for the baseline visibility impact modeling would be listed. The basic design criteria information is necessary to compare to the unit RACT/BACT/LAER database information provided in appendix A and to evaluate the applicability of the control technologies proposed.

The unit design information should include information about the design and operation of each unit and its currently installed emission controls. Information would include unit throughput capacity (tons BLS/day, MMBtu/hr heat input), fuels used and average percentages of each fuel by weight or heat content, basic design (spreader stoker, pile burner, suspension burner, etc), emission controls in place, and control efficiencies/emission rates of those controls, and other appropriate design and operational information. This information provides the basis for the evaluations in the rest of the report. Please provide this information in a single location of the report, such as this Section or tables in the Appendix.

#### #11 Power Boiler:

- Foster Wheeler Spreader-stoker type boiler, installation ~1976
- Nominal capacity: 580,000 lb steam/hour. At 64.23% design efficiency, @1,125 Btu/lb steam generated, nominal fuel heat input capacity = 1,016 MMBtu/hr
- Fuels burned: Hog fuel, coal, effluent treatment solids, & fuel oil (#6, <2% sulfur).
- Fuel oil used primarily for startup, shutdown & upsets

The No. 11 Boiler Upgrade Project, completed in late 2006, improved boiler operating ability to meet variable site steam demand while firing high moisture, high ash content fuels by upgrading the overfire air, fuel feed, and emission control systems. A summary of average operating rates before and after the Upgrade Project is presented in the table below:

Parameter	Units	Pre-Project Baseline	2007	Change: 2007 value vs. Baseline
Steam Rate	KPPH	371	413	42
Fuel Heat Input (from steaming rate & design efficiency)	MMBtu/hr	652	724	72
Hog Fuel	Tons/hr	21.4	20.8	-0.6
Coal	Tons/hr	6.8	9.7	2.8
Sludge	Tons/hr	6.6	6.9	0.3
Fuel Oil	Gal/hr	11.5	17.4	5.8
Hog Fuel	% Heat input, HHV basis	56.4%	49.9%	-6.6%
Coal	% Heat input, HHV basis	25.9%	33.2%	7.4%
Sludge	% Heat input, HHV basis	17.4%	16.5%	-0.9%
Fuel Oil	% Heat input, HHV basis	0.3%	0.4%	0.1%

## #10 Recovery Furnace:

- B&W low-odor type recovery furnace, installation ~1975
  - Furnace upgrades in 1995 (third precipitator added) and 2002 (upgrade to high-concentration black liquor firing).
  - Steam capacity limited at ~808 kpph steam, equivalent to ~270 kpph BLS
  - Supplemental use of #6 fuel oil, primarily for startup, shutdown & malfunction
2. In several places in the report various emission rates are presented. We are unable to substantiate the basis for the Recovery Furnace SO<sub>2</sub> emissions used for modeling. Based on annual SO<sub>2</sub> emissions reported to us by your company, the maximum day 24 hour emission rate should be considerably higher than 2 pounds per hour reported for the maximum day over the 3 baseline years. For example the 2005 emission inventory data you reported to us indicates an emission rate of 50 tons/year, a remarkably low number considering the design black liquor throughput. Assuming you operated the recovery furnace for 50 weeks per year, this would result in an annual average hourly SO<sub>2</sub> emission rate of over 11 lb/hour, considerably higher than the rate reported in this report. Not having the model input and other files it is impossible to determine if the Recovery Furnace SO<sub>2</sub> emissions in the report differ from what was modeled.

This apparent error for the SO<sub>2</sub> emissions brings into question the accuracy of the determination of all of the highest 24 hour emissions used for visibility impacts modeling.

*The “maximum emission day” used for modeling was not erroneous, it was selected based on BART Guidance regarding determination of the “maximum emission day”. It is true that annual average SO<sub>2</sub> emissions from the Recovery Boiler were about 11 pounds per hour. However, most of the annual average emissions derive from periods of low utilization rate (low liquor firing periods), or startup, shutdown, and malfunctions which according to BART guidelines, should not be considered for visibility impact modeling.*

*Prior to modeling, Weyerhaeuser determined the “maximum emission day” for each BART pollutant (NO<sub>x</sub>, SO<sub>2</sub>, and PM) during the 2003-2005 baseline period. Daily emissions rates of NO<sub>x</sub> and SO<sub>2</sub> were determined from continuous emission monitors on both the No. 10 Recovery Furnace and the No. 11 Power Boiler; hence, there is a high level of confidence in the measured rates. Daily speciated particulate matter emissions rates were estimated from daily operating rate data using time-variable emission factors derived from the most recent quarterly Method 5 stack test. Consequently, there is a relatively high confidence level in the daily particulate emissions rate estimates as well.*

*“Maximum emission day” for each BART pollutant was the maximum daily BART-source emissions rate during the baseline period for days reflecting “steady state operating conditions during periods of high capacity utilization”, excluding emissions during startup, shutdown & malfunction periods. Section 2.4 of the BART Modeling Protocol says;*

*The BART Guideline states, “the emission estimates used in the models are intended to reflect steady-state operating conditions during periods of high capacity utilization.” These emissions should not generally include start-up, shutdown, or malfunction emissions.*

*Therefore the emissions during low operating rate, non-steady state operations, startup, shutdown, and malfunction conditions were not considered in determining the maximum emission rates for modeling. (For further discussion, we can refer to the selected operating conditions as “steady state, high rate” days.) During steady state, high rate operations, No. 10 Recovery Furnace emissions are in fact remarkably low for the amount of black liquor fired, with typical emission concentrations less than 1 ppm.*

*For steady state, high rate days during the baseline period, the maximum emission day for NO<sub>x</sub> was June 8, 2003, when the sum of NO<sub>x</sub> emissions rates from the three BART eligible units was 648 pounds per hour. Similarly, November 27, 2004 was the steady-state, high rate day with the highest BART source SO<sub>2</sub> emissions, at an emissions rate of 346 pounds per hour. On that day, #10 Recovery Furnace SO<sub>2</sub> emissions were lower than average at 2 pounds per hour, yet for all three BART sources combined, this was the highest SO<sub>2</sub> emissions rate day for the baseline period. Finally, June 17, 2003 was the maximum emissions day for PM<sub>10</sub>, with an emissions rate of 91 pounds per hour. Accordingly, for the baseline, total BART pollutant emissions modeled were 1,085 pounds per hour.*

*Defining “maximum emission day” on a pollutant-by-pollutant basis in this way over estimates the actual BART eligible emissions during the baseline period. In actual operation, maximum emissions of the BART pollutants did not occur on the same day. The steady state, high rate baseline day with the highest total BART pollutant emissions was June 28, 2003. On that day, emissions rates were: 633 pounds per hour NO<sub>x</sub>; 171 pounds per hour SO<sub>2</sub>; and 85 pounds per hour PM<sub>10</sub>; for a total BART pollutant emission rate of 889 pounds per hour, significantly lower than the 1,085 pounds per hour used for baseline modeling.*

*It should be noted that for No. 10 Recovery Furnace, emissions of NO<sub>x</sub> and SO<sub>2</sub> tend to be inversely related. That is under high load NO<sub>x</sub> emissions tend to be high and SO<sub>2</sub> emissions tend to be low due to good combustion and sulfur recovery. The majority of the annual SO<sub>2</sub> emissions from the Recovery Furnace are from non-steady state operations during startup and shutdown periods, when sulfur recovery efficiency is poor. In contrast, during these high-SO<sub>2</sub> emission periods, NO<sub>x</sub> emission rates are low because of low flue gas flow rates.*

*Also consider that the annual average emission rate of 11 pounds per hour is very small and almost insignificant compared to the boiler’s NO<sub>x</sub> emission rate of over 200 pounds per hour on the highest emitting day or the No. 11 Power Boiler’s emission rates of over 300 pounds per hour each for NO<sub>x</sub> and SO<sub>2</sub> on the highest emitting days. Using the annual average SO<sub>2</sub> emission rate for visibility modeling would not significant change modeled results.*

*It is also important to note the relationship between the No. 10 Recovery Furnace and the No. 11 Power Boiler. No. 10 Recovery Furnace is tied directly to the kraft mill process, and normally operates at steady rate at or near full steaming rate (800-850 thousand pounds of steam per hour). This maximizes pulping liquor chemical recovery rate and satisfies the majority of site steam demand. Under these conditions, No. 11 Power Boiler and the other power boiler supply the remainder of the site steam requirement, operating as a “swing” boilers to match varying site steam demand. However, when No.10 Recovery Furnace is shut down or operating at low rate, No. 11 Power Boiler is operated as a baseload boiler, steaming at a high and steady rate. Consequently, No. 11 Power Boiler emissions rates are highest under conditions when No. 10 Recovery Furnace emissions are lowest.*

**Individual BART Pollutants: Highest BART-Source Emission Day for Each BART Pollutant (NO<sub>x</sub>, SO<sub>2</sub>, & Each PM-10 Fraction)\***

Highest BART-source emissions day for each BART pollutant during steady state operation. These were the values used for modeling in Weyerhaeuser's BART evaluation, and were also provided to EPA Region 10 for their regional haze modeling.

BART Unit	NO <sub>x</sub> , lb/hr	SO <sub>2</sub> , lb/hr	TSP, lb/hr	EC, lb/hr	PMF, lb/hr	PMC, lb/hr	CPM, lb/hr	SOA, lb/hr	SO <sub>4</sub> , lb/hr	NSIA, lb/hr	Total PM10, lb/hr	Total, lb/hr	Comment:
Date	6/8/03	11/27/04	6/17/03	6/17/03	6/17/03	6/17/03	6/17/03	6/17/03	6/17/03	6/17/03	06/17/03		
#11 Power Boiler	426	344	63	9	31	8	15	12	3	0	63	834	Multifuel swing boiler
#10 Recovery Furnace	222	2	15	0	7	3	12	2	4	6	22	261	Kraft recovery furnace
Smelt Dissolver	na	na	5	0	4	0	1	0	0	1	6	11	Integrated with #10 Recovery
Sum	648	346	83	9	43	11	28	14	8	6	91	1,085	

\* At steady state operating conditions, not including startup, shutdown or malfunction.

**All BART Pollutants: Highest BART-Source Emission Day for the Sum of all BART Pollutants\***

6/28/2003: #11 Power Boiler was running hard due to increased steam demand, with #10 Recovery Boiler slowed to ~90% target rate. Smelt Dissolver operation integrated with #10 Recovery Furnace.

These values represent the maximum actual BART pollutant emission day for the BART source during steady state, high rate operations in the Baseline period. In Weyerhaeuser's view, these were the most appropriate values for use in modeling Baseline visibility impacts.

However, based on feedback from EPA and WDOE regarding the modeling protocol, Baseline modeling was instead done using the maximum emission day for each BART pollutant. Thus the "Baseline actual" emission values used in modeling were substantially higher than actual emissions that occurred during any actual day of the 2003-2005 Baseline period.

BART Unit	NO <sub>x</sub> , lb/hr	SO <sub>2</sub> , lb/hr	TSP, lb/hr	EC, lb/hr	PMF, lb/hr	PMC, lb/hr	CPM, lb/hr	SOA, lb/hr	SO <sub>4</sub> , lb/hr	NSIA, lb/hr	Total PM10, lb/hr	Total, lb/hr	Comment:
#11 Power Boiler	430	169	59	8	30	8	14	11	3	0	60	659	#11 running hard with #10 slowed
#10 Recovery Boiler	203	2	13	0	7	2	11	2	4	5	20	238	#10 Recovery @ ~90% target rate
Smelt Dissolver	na	na	5	0	3	0	1	0	0	1	5	10	Smelt Dissolver tied to #10 Boiler
Sum	633	171	77	9	40	11	26	13	7	6	85	889	

\* At steady state operating conditions, not including startup, shutdown or malfunction.

TSP = Total Suspended Particulate, also known as "front half catch". Emission rates calculated from quarterly source test emission factors & daily production rates.

CPM = Condensable Particulate Matter, also known as "back half catch". Emission rates calculated from quarterly source test emission factors & daily production rates.

EC = Elemental Carbon; filterable PM2.5 present as elemental carbon

PMF = Fine Particulate Matter; Filterable particulate <PM2.5, excluding

PMC = Coarse Particulate Matter; Filterable PM10 >PM2.5

SOA = Secondary Organic Aerosol; CPM present as organic compounds

SO<sub>4</sub> = Sulfate; CPM present as sulfur oxides

NSIA = Non-SO<sub>4</sub> Inorganic Aerosol; CPM that is neither organic or sulfate

"Total PM-10" includes both filterable PM-10 (EC, PMF & PMF) and CPM (SOA, SO<sub>4</sub> & NSIA).

3. In the second full paragraph on page 15, reference is made to a Figure 1, showing the current configuration of the power boiler ESP and stack. This figure is missing from our package. Many of the following comments could be reduced or eliminated by including appropriate scale drawings of the recovery furnace and the power boiler configurations.

*Figure 1 is shown below, and will be included in the revised BART Report.*

Figure 1: No. 11 Boiler Precipitator & Stack



4. No. 10 Recovery furnace, NOx control evaluation, page 8. In Step 1, you note that the staged combustion is already practiced in the recovery boiler. What level of staged combustion is currently utilized in the furnace – secondary, tertiary, or quaternary staging? Are there opportunities to ‘fine tune’ the staged combustion to further reduce the NOx production? Please discuss the possibility of further NOx reductions through improvements to the existing staged combustion system.

*The dual purposes of No. 10 Recovery Furnace are to recover inorganic pulping chemical for re-use in the pulping process, and to generate steam and power from the firing of concentrated black liquor in the furnace. The furnace is designed and operated to produce chemically reducing conditions in the lower furnace for efficient recovery of inorganic pulping chemical, while maintaining oxidizing conditions in the upper furnace to achieve full and complete combustion of the concentrated black liquor solids fired. The addition of combustion air has been fine-tuned to balance these reducing and oxidizing functions, while optimizing thermal efficiency by adding only the amount of combustion air needed to assure complete oxidation of organic and reduced sulfur compounds.*

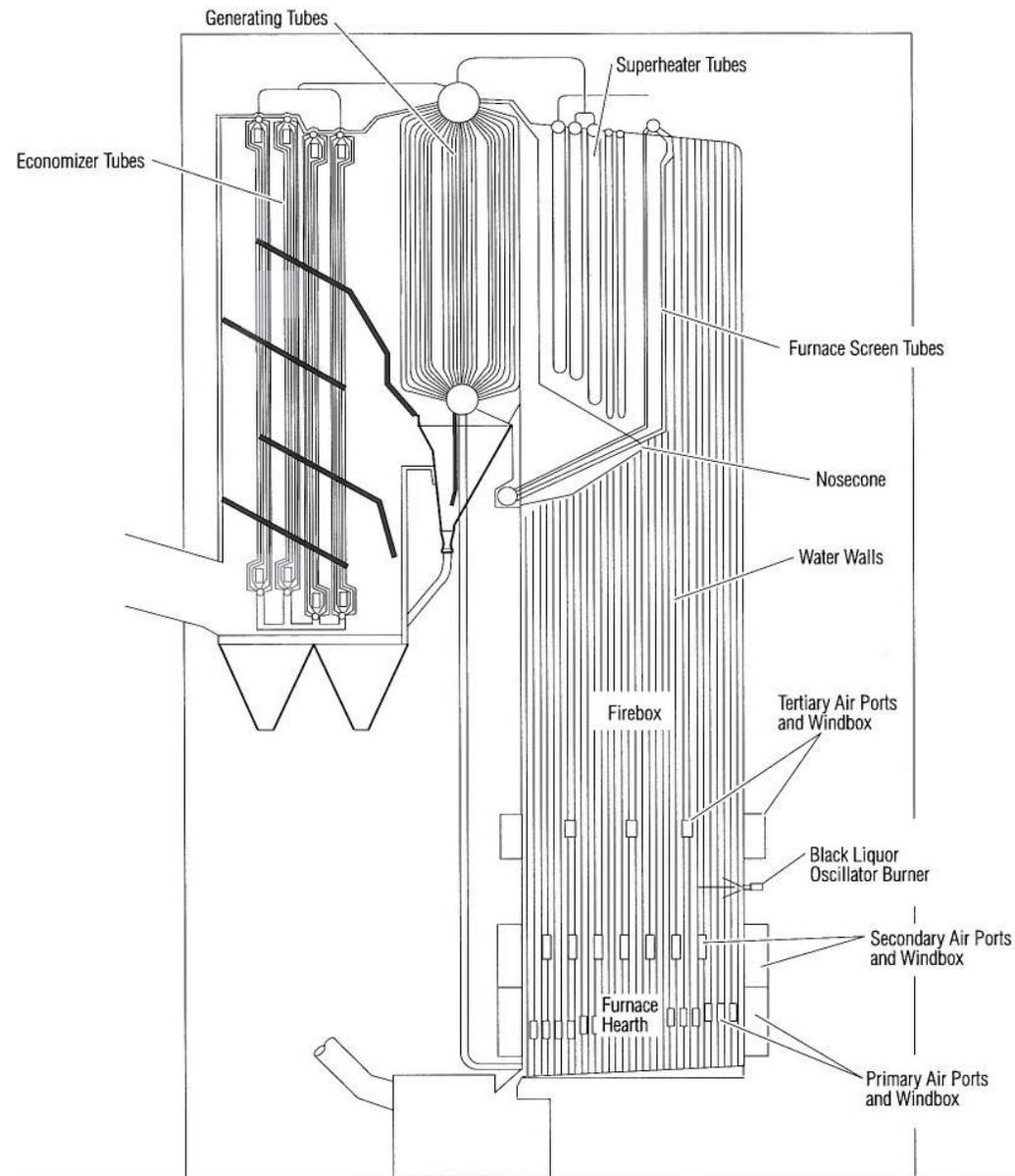
*As shown in Figure 2 (below), No. 10 Recovery Furnace delivers primary, secondary and tertiary combustion air into the boiler firebox. Tertiary air was added in 1995 when the lower section of the Recovery Furnace was replaced. Primary and secondary air systems include air pre-heating, while tertiary air is at ambient temperature. Primary, secondary and tertiary air ports are located roughly 17, 28 and 63 feet above ground level, respectively. This air inlet distribution generates a reducing zone between the primary and secondary air ports, a liquor drying zone between the secondary and tertiary air ports, and an oxidizing zone in the upper firebox between the tertiary air ports and the boiler screen tubes.*

*Adding a fourth stage would again require placing a new section in the Recovery Furnace. There is not likely enough room within the furnace between the tertiary air port and the start of the boiler tubes to add a fourth stage of combustion; hence, the furnace would have to be rebuilt and the upper section raised. This would likely require rebuilding the entire boiler and boiler building.*

*Fine tuning recovery furnaces are very complex operations with many trade-offs. For example, as explained in response to Comment 2 the emissions of NOx and SO<sub>2</sub> tend to be inversely related. Hence, fine tuning the furnace operation to reduce NOx emissions would likely significantly increase SO<sub>2</sub> emissions. There is also a very complex relationship between low end furnace temperature, NOx formation, SO<sub>2</sub> formation, sulfur recovery, and other furnace operating conditions.*

*Finally, No. 10 Recovery Furnace’s current NOx emissions performance indicates that combustion air is already well tuned, in comparison with emissions from fossil fueled boilers equipped with staged combustion for NOx control. In 2007, NOx emissions from No. 10 were approximately 0.125 pound per million Btu of fuel heat input (0.125 lb/MMBtu). This emission rate is lower than the lowest “presumptive BART” level established for any type of coal fired Electric Generating Unit, and less than half the NSPS Subpart Db standard for boilers firing residual oil.*

Figure 2- Diagram of No. 10 Recovery Boiler showing combustion air ports & boiler tubes



Is SNCR or SCR available to use on recovery furnaces? If not, what are the reasons that prevent their use? If either of these technologies is available for use, what is the technical and economic feasibility to install on this recovery furnace?

*We could not find any recovery furnace that has SNCR or SCR installed and operating; hence, such technology has not been demonstrated in practice, either for new or for existing units. There are several complex issues that need to be resolved before SNCR can seriously be considered as a feasible control technology for recovery furnaces. Primary among the reasons is that recovery furnaces are designed to recover chemicals, mostly sodium and sulfur. Generating steam is a secondary aspect of a recovery furnace. SNCR requires injection of*

*ammonia or urea into the furnace within a specific temperature range. Existing furnaces, such as the one in Longview, would have to have significant modifications in the upper sections to allow for the necessary injection ports. In addition the long term impacts on the chemical recovery process of injecting ammonia or urea have not been studied and need to be need to be thoroughly evaluated before such technology can be consider feasible. Other factors that need to be evaluated before SNCR can be considered feasible include the interaction between ammonia and the other chemicals in the recovery furnace; such as, chlorine, sodium, and sulfur.*

*SCR like SNCR requires a reaction between the exhaust gas and ammonia or urea. Unlike SNCR, SCR does not require chemical inject into the recovery furnace, but relies on a catalyst to facilitate the reaction between ammonia and urea at a lower temperature. We could not find any case where SCR has even been attempted on a pilot scale on a recovery furnace. Of great concern is the likelihood of catalyst poisoning by the alkali particulate that recovery furnaces generate if the SCR system is installed before the ESP, and in the case of No. 10 Recovery Furnace the lack of space between the furnace outlet and the ESP and lack of ground space for the SCR system. Installing the SCR system after the ESP would also have concerns about catalyst poisoning and would require reheating the exhaust gas.*

A statement in the report indicates that alkali contamination of the SCR catalyst will deactivate it. How fast does this deactivation occur? Can the contamination be removed by routine washing of the catalyst?

*These are valid questions but they remain unanswered in practice, since SCR has not been employed for NOx control on any new or existing Recovery Furnace. As stated above, the process of alkali contamination of the catalyst need considerable study before SCR could be considered feasible for a recovery furnace.*



*No. 10 Recovery Furnace with ESP*

5. Table 4 on Page 11. We are confused as to what this information represents. It appears to be the emissions recorded after the 2006(?) boiler upgrade project. Is this true? Do the maximum emission rates in the table represent the high 24 hour values or peak hourly values, or the average hourly value on the day with the highest 24 hour emissions? This is useful information to know for evaluating additional emission controls, but is not used for this purpose. I note the emission rates actually stated to have been modeled in Table 7 (page 23) are repeated in Table 3 instead. Also it is not clear that the modeled emission rate for particulates from the No. 11 Power Boiler is based on the currently permitted or baseline actual emission rate achieved by the currently installed PM emission control. Please clarify this.

*Table 4 was intended to show the average and maximum hourly rates since the boiler upgrade project was completed. Because these rates were not used in the modeling we will remove Table 4 from the report.*

*Tables 3 and 7 represent the emission rates for No. 11 Power Boiler that were used for the modeling and were determined based on the highest emitting day for each BACT pollutant during the Baseline period, as described in the BART Modeling Protocol and the response to Comment 2.*

*Current particulate emissions (after installation of the electrostatic precipitator as part of the No. 11 Boiler Upgrade Project) are substantially lower than the 2003-2005 Baseline emission rates, but the emission decrease is not federally enforceable, so Baseline emissions were used for modeling.*

6. No. 11 Power Boiler, SO<sub>2</sub> control evaluation, Page 12 and 14. On these pages, you note that the coal used in this boiler is a low sulfur western coal. What is the type and source (mine or region) of the coal and what is its average/nominal sulfur content? Is a lower sulfur coal available for use that could be substituted? How much sludge is fired in the boiler annually? What is the sulfur content of the sludge fired? Is it possible to reduce the sulfur in the sludge prior to combusting it?

*The coal used in No. 11 Power Boiler is low sulfur bituminous coal from the Powder River Basin.*

*Currently (since late 2007), coal is supplied by Rio Tinto Energy, from the Spring Creek Coal Mine located southeast of Billings, Montana. For shipments in 2007, sulfur content varied from 0.37-0.48 percent (dry basis). Spring Creek's sulfur content is lower than the previous coal supply (from Bull Mountain Mine), but it also has lower fuel heating value and higher sodium content, which has resulted in boiler downtime due to scaling and pluggage problems.*

*Weyerhaeuser and Rio Tinto recently agreed to a three-year contract stipulating that Spring Creek will supply all the mill's coal, unless that coal causes excessive boiler operability issues.*

*Bull Mountain Mine near Billings, Montana, had supplied coal for Longview for the last several years, until mine operations shut down in late 2007. Bull Mountain's coal sulfur content had ranged from 0.5-0.9 percent (dry basis). Weyerhaeuser is not aware of lower sulfur coal supply options for the Longview mill.*

*From 2003-2007, annual sludge firing has ranged from 56,000-60,000 dry tons per year. Sludge sulfur content is not routinely monitored, but periodic tests from 1990 to the present have shown sludge sulfur content to be approximately 0.3-0.4 percent (dry basis). There is no known process for reducing the sludge sulfur content.*

*In this discussion of fuel sulfur content, it is worth noting that No. 11 Boiler's flue gas SO<sub>2</sub> emission rate is less than the fuel sulfur feed load, and the percentage of fuel sulfur emitted as SO<sub>2</sub> is affected by other characteristics of the fuel feed streams. A good portion of the sulfur is captured and removed in the bottom ash and flyash, due to the presence of alkaline metal components in the fuel feed streams. This has been noted at many combination fueled boilers, and is described in NCASI Technical Bulletin No. 640, "Sulfur Capture in Combination Bark Boilers". The amount of sulfur retention in the boiler ash streams is affected by the ratio of sulfur to alkaline components in the fuel feed streams, and the alkaline ash content of the sludge feed stream is considerable in comparison with the sludge sulfur content. The percent of sludge sulfur emitted as SO<sub>2</sub> has not been quantified for No. 11 Boiler, because there are many operating variables that make it difficult and costly to perform a sulfur mass balance in the boiler. However, it is clear that when firing sludge in the boiler, the SO<sub>2</sub> emissions increase is substantially lower than would be seen if all the sludge sulfur were emitted as SO<sub>2</sub>.*

7. No. 11 Power Boiler, SO<sub>2</sub> control evaluation, Page 11. Did the dry sorbent injection system go through a BACT review?

*The dry sorbent injection system did not go through BACT review. Ecology determined that the project was not subject to BACT because there was not an increase in emissions from the project.*

If so, please provide the reference information for that BACT report. What is the design and actual SO<sub>2</sub> removal for the Trona dry sorbent system?

*The purpose of the dry sorbent injection system was to provide enough SO<sub>2</sub> control to assure that an increase in No. 11 Power Boiler steaming rate, with a proportional increase in fuel heat input rate and fuel sulfur loading, would not result in a significant SO<sub>2</sub> emissions increase. Accordingly, to accommodate a maximum annual steaming rate increase of ~33 percent, the Trona system was designed to remove 25 percent of the predicted precipitator inlet SO<sub>2</sub> load at the increased operating rate.*

*The electrostatic precipitator vendor, PPC, also supplied the Trona Dry Sorbent Injection system. PPC's emission control design was based on the requirement to remove 25% of inlet SO<sub>2</sub>, at a projected inlet SO<sub>2</sub> load of approximately 88 ppmv and 180 pounds per hour. Given the stoichiometric Trona demand of 2.635 pounds Trona per pound of SO<sub>2</sub>, the theoretical Trona demand for removing 45 lbs/hr of SO<sub>2</sub> is 119 pounds of Trona per hour. PPC estimated actual Trona demand would be approximately 150 pounds per hour. This assumed Trona effectiveness at SO<sub>2</sub> removal would be about 80 percent of theoretical, taking into account other acid gases (HCl, H<sub>2</sub>SO<sub>4</sub>, NO<sub>2</sub>) competing with SO<sub>2</sub> for reaction with the Trona, and some unreacted Trona passing through the system. They accordingly selected a storage tank, mill and blower system capable of delivering 200 pounds per hour of milled Trona to the ID fan inlet duct.*

*Weyerhaeuser has conducted several trials attempting to determine SO<sub>2</sub> removal effectiveness of the Trona system. The clearest results were from a three day trial in July 2007. Estimated Trona effectiveness was 0.176 pound SO<sub>2</sub> removed per pound Trona injected (5.7 pounds Trona required per pound of SO<sub>2</sub> removed). This is roughly 50 percent of the maximum theoretical effectiveness, somewhat less than PPC's design estimate of 80 percent theoretical effectiveness.*

Why is Trona used instead of hydrated lime for SO<sub>2</sub> control from this boiler?

*Trona was the sorbent material recommended by PPC, the precipitator vendor, as the simplest and most cost effective means of achieving the control requirements of the Boiler Upgrade Project. Equipment requirements were simple, requiring only a storage tank, mill and blower system to inject the milled sorbent directly into the existing flue gas ductwork upstream of the ID fan. Vendor information showed that Trona provides similar acid gas removal performance to sodium bicarbonate, at roughly half the price. Finally, although the literature shows that the ratio of Trona feed to SO<sub>2</sub> load increases exponentially as control efficiency requirements increase, the studies also showed that Trona can be used effectively (in terms of SO<sub>2</sub> removed per pound of Trona injected) for systems with modest control efficiency requirements.*

8. No. 11 Power Boiler, SO<sub>2</sub> control evaluation, Page 14. Are there characteristics of the sludge that can be modified to reduce the sulfur content of the sludge? What is the water content of the sludge as currently fired? Could the sludge be further dewatered before being introduced to the boiler, resulting in less coal and wood fuel needed to dry the sludge in the boiler?

*Effluent sludge composition, including the sulfur content, reflects the nature of the process wastewater source. A Kraft pulp & paper mill utilizes sulfur in the sulfate pulping process. Pulping chemical losses are minimized in order to keep down costs of purchased makeup chemicals needed to maintain the proper inventory of soda, calcium and sulfur in the pulping liquor. However, some losses to wastewater are inevitable, and these result in the sodium, calcium and sulfur content of the effluent treatment sludge. There is no practical means of modifying the sludge to reduce the sulfur content.*

*The sludge is dewatered to typical dryness values of 35-37 percent solids (63-65 percent moisture) in four screw presses. These presses reflect the best technology economically available for dewatering pulp & paper mill effluent sludge. Sludge thermal drying processes would be required to decrease moisture content further.*

*Sludge is rejected from the boiler when moisture and ash content are too high, and the resulting net fuel heat value is too low, for economical combustion. The ash content of the sludge includes non-combustible inorganic material in wood fiber and secondary solids biomass, lime mud losses from pulping chemical recovery process, and clay and calcium carbonate filler from the paper machines and deinking processes.*

*Typically, sludge is rejected from the boiler when dryness is less than 30%, or when ash is greater than 30 percent. More stringent criteria are sometimes used, such as when hog fuel is wet due to wet weather, or if No. 10 Recovery Furnace is down and No. 11 Power Boiler must run at higher rate to make up the steam demand.*

9. No. 11 Power Boiler, SO<sub>2</sub> control evaluation, Page 14 - 16. You need to include a discussion of optimizing the effectiveness of the current dry sorbent injection system, including the use of a different chemical in the dry sorbent injection system. Would use of hydrated lime increase SO<sub>2</sub> removal compared to the use of Trona?

*Hydrated lime would not be feasible with the No. 11 Power Boiler, because the dry sorbent is injected just ahead of the ID fan, utilizing the fan for mixing, and hydrated lime would be expected to plate out on the ID fan blades, posing a threat to reliable boiler operation and worker safety. The storage tank and delivery system are also designed for Trona, but may not be suitable for hydrated lime, because of lime's strong tendency to solidify and plug up storage and conveyance systems.*

10. No. 11 Power Boiler, NO<sub>x</sub> control evaluation, Page 16. What are the pertinent design characteristics of this boiler that affect NO<sub>x</sub> production? Questions that come to mind include:

- a. Is staged combustion already used to optimize combustion and reduce NO<sub>x</sub>? If so, describe the existing staged combustion?

*The current system has two stages of combustion. The first stage uses under-fire air in which fixed carbon is burned on the traveling grates. The second stage involves overfire air and the combustion of hydrocarbons and CO driven off the fuel on the grates.*



*Underfire air*



*Overfire air*

- b. How do the different fuels (principally coal, wood and sludge) enter the boiler, mixed together or from separate entry points?

*All the fuels are mixed and enter the boiler through one of several fuel spreaders. The fuel is then spread onto a traveling grate where the fixed carbon is burned with under-fire air and the volatile hydrocarbons are driven off and burned above the grate with overfire air.*



*Fuel as it enters the boiler*



*Fuel on the grate*

- c. Are there opportunities to reduce NO<sub>x</sub> through changes to how the various fuels are introduced to the boiler? i.e. could wet sludge be introduced mixed with the coal to help reduce peak flame temperatures?

*As stated above the various solid fuels are already mixed before entering the boiler. Unlike larger boilers that only fire coal or utility boilers that burn pulverized coal in suspension, the fixed carbon is burned on the grate and hydrocarbons are burned in a combustion zone above the grate. In addition coal is typically a small portion of the total heat input, for example in 2006 coal averaged about 20 percent of the total heat input to No. 11 Power Boiler.*

- d. How much of the NO<sub>x</sub> is fuel NO<sub>x</sub> and how much is thermal NO<sub>x</sub>?

*The combustion temperatures are low enough where most of the NO<sub>x</sub> formation is due to fuel nitrogen and not thermal NO<sub>x</sub> formation.*

11. No. 11 Power Boiler, NO<sub>x</sub> control evaluation, Page 17. The discussion on the use of SCR on this power boiler is not convincing that SCR is not technically feasible. The technology is being applied and used successfully on coal fired power plants. A common location is classed as hot-side/dirty – the SCR bed is located before the economizer, SO<sub>2</sub> control, and the particulate control device. Based on your boiler description on this page, this appears to be a viable location to install SCR control for this boiler. The level of control achievable by an SCR system installed could be optimized to what can reasonably be achieved in the space available for an SCR catalyst bed.

*It is true that hot-side/dirty is a common location for new coal fired utility boilers; however, such installations are not common for existing mixed fuel boilers such as the No. 11 Power Boiler. In*

fact in establishing presumptive BART for coal fired boilers, EPA concluded that add on controls such as SCR were not presumptive BART for any coal fired boilers except for cyclone fired boilers, which have much higher NOx emissions.

Adding hot-side SCR to the No. 11 Power Boiler would be a complex task because of the existing structures and duct work. We estimated the cost of adding SCR would be in the range of \$163,000,000 and would result in a cost of about \$13,000 to remove a ton of NOx.

## ADD ON NOx CONTROLS ECONOMIC ANALYSIS SUMMARY

Parameter	NOx Control	
	SNCR	SCR
TOTAL INSTALLED CAPITAL COST (\$)	<b>15,805,615</b>	<b>98,785,095</b>
FIRST YEAR O&M COST (\$)		
Operating Labor (\$)	35,007	175,625
Maintenance Material (\$)	70,014	351,250
Maintenance Labor (\$)	35,007	175,625
Administrative Labor (\$)	0	0
<b>TOTAL FIXED O&amp;M COST</b>	<b>140,028</b>	<b>702,500</b>
Reagent Cost	127,272	260,112
SCR Catalyst	0	131,276
Electric Power Cost	35,649	35,649
<b>TOTAL VARIABLE O&amp;M COST</b>	<b>162,922</b>	<b>427,037</b>
<b>TOTAL FIRST YEAR O&amp;M COST</b>	<b>302,949</b>	<b>1,129,537</b>
FIRST YEAR DEBT SERVICE (\$)	2,250,364	14,064,775
<b>TOTAL FIRST YEAR COST (\$)</b>	<b>2,553,313</b>	<b>15,194,312</b>
<b>Power Consumption (MW)</b>	<b>0.1</b>	<b>0.1</b>
<b>Annual Power Usage (kW-Hr/Yr)</b>	<b>0.7</b>	<b>0.7</b>
CONTROL COST (\$/Ton Removed)		
<b>NOx Removal Rate (%)</b>	<b>25.0%</b>	<b>75.0%</b>
<b>NOx Removed (Tons/Yr)</b>	<b>382</b>	<b>1,146</b>
<b>First Year Average Control Cost (\$/Ton NOx Rem.)</b>	<b>6,686</b>	<b>13,263</b>
<b>Incremental Control Cost (\$/Ton NOx Removed)</b>		<b>16,551</b>
<b>PRESENT WORTH COST (\$)</b>	<b>27,572,741</b>	<b>162,918,392</b>

12. No. 11 Power Boiler, NO<sub>x</sub> control evaluation, Page 17. The discussion on the use of SNCR is not convincing that the technology is not feasible for installation on this boiler. In Washington this technology is used at Kimberley-Clarke in Everett, apparently successfully after problems with an ammonium chloride plume was corrected. A recent review of reports about the use of SNCR on dry process cement plants with higher SO<sub>2</sub> emission rates indicates no sulfate plume is generated. A chloride plume can be traced to using salty hog fuel. Is there a method that Weyerhaeuser can assure that the hog fuel either is not 'salty' or 'salty hog fuel' and 'non-salty' fuel is mixed to assure a low salt, non-problematic salt content?

*We understand that the ammonium chloride plume problem has indeed been corrected at Kimberley Clark. Based on Ecology's Statement of Basis (SOB) for Kimberley-Clark's Title V permit, the No. 14 boiler was repermited to avoid a chlorine plume. The SOB says:*

*The repermitting was to prevent the unintentional formation of a visual plume from No. 14 which was condensing outside the stack and hence was not being picked up by the No. 14 boiler COMS. The plume was ammonium chloride salt, formed by the reaction of the ammonia being added to the stack for NO<sub>x</sub> control and chloride in the wood waste. The repermitting allowed KCWW to discontinue ammonia addition to No. 14, which solved the plume problem. Visual opacity has been minimal since that time. KCWW requested that this requirement be eliminated in the permit application and that the requirement for visual opacity readings under Method 9 only be required during those rare times when the COMS is not operating. Ecology agrees, the visual observation requirement has been eliminated from the order and permit by Order 1908.*

*Kimberly Clark staff has confirmed that the SOB is correct and ammonia is no longer added to the No. 14 boiler for NO<sub>x</sub> control.*

*Weyerhaeuser is doing what it can to minimize the chloride content of its fuel. For example, Longview does not receive fuel that has been shipped on salt water. However, in today's market Weyerhaeuser must obtain wood and fuel from wherever it can and that includes coastal areas that tend to have much higher chloride content in the wood.*

13. No. 11 Power Boiler, NO<sub>x</sub> control evaluation, Page 19. In the sentence discussing Step 3, does the 35 to 50% NO<sub>x</sub> reduction apply to only natural gas reburning, only to over fire/staged combustion, or to the combination of reburning and overfire air/staged combustion? Since neither NO<sub>x</sub> reduction technique is discussed until Step 4, this sentence is unclear and the whole process description needs to be expanded for clarity.

*In the reburning process, primary combustion occurs low in the combustion zone in a fuel rich environment and secondary combustion takes place above the combustion zone with additional combustion air and fuel. Hence natural gas reburning must have overfire air and staged combustion. As described above, the No. 11 Power Boiler already practices a level of staged combustion in which fixed carbon is burned on the traveling grate in a fuel rich environment and volatile hydrocarbons are burned above the grate in a secondary combustion zone in an oxygen rich environment; vary much like what would happen with natural gas reburning. Therefore it is not likely that reburning would have its maximum reduction of about 50 percent.*

*Weyerhaeuser is also concerned about possible NSPS emission limit implications of firing natural gas in No. 11 Boiler. The Boiler is subject to NSPS Subpart D, with NOx emission limits prorated based on the relative fuel heat input of liquid and solid fossil fuels fired (fuel oil and coal). When co-firing fuel oil and coal at the same time, the limit is calculated as:*

$$PS = (0.30y + 0.70z)/(y+z)$$

*Where: y = percentage of total fuel heat input from liquid fossil fuel*

*z = percentage of total fuel heat input from solid fossil fuel or solid fuel*

*There is some question of whether adding natural gas burners to the boiler would trigger NSPS standards for natural gas firing. However, a plain reading of NSPS Subpart D would suggest that if natural gas were fired in this boiler that is subject to Subpart D, then the NOx emission limit would be prorated as follows:*

$$PS = (0.20x + 0.30y + 0.70z)/(x+y+z)$$

*Where: x = percentage of total fuel heat input from gaseous fossil fuel*

*y = percentage of total fuel heat input from liquid fossil fuel*

*z = percentage of total fuel heat input from solid fossil fuel*

*Under conditions where the boiler was firing wood, sludge, and a small amount of coal, if there were a substantial heat input from natural gas, the resulting emission standard would approach 0.20 lb/MMBtu. This would be unattainable given the boiler's overall fuel mix.*

14. No. 11 Power Boiler, NOx control evaluation, Page 19. In the step 4 discussion, natural gas reburning is 'estimated to exceed \$10,000 per ton of NOx reduced'. What are the significant elements of the estimated control cost? Please provide the estimate for review.

*As described in the text, natural gas reburning requires that about 20 percent of the heat input be supplied by natural gas and that reburning can be expected to reduce NOx emissions by about 35 percent. As shown in Appendix B an EPA Combined Heat and Power Partnership study estimated the costs of biomass fuels to be about \$2 per MMBtu and natural gas to be about \$6 per MMBtu. The table below shows that the fuel cost alone would result in a cost of over \$9,000 per ton of NOx removed. This does not include the cost of modifying the boiler, nor does it consider economic and environmental trade offs between burning green house gas neutral biomass verses greenhouse gas generating natural gas.*

## Natural Gas Re-burning

### Inputs

Total heat input	750	MMBtu/hr
Biomass Fuel Cost	2	\$/MMBtu
Natural Gas Cost	6	\$/MMBtu
Reburning NOx Removal Efficiency	35%	

### Calculations

Net Cost of Natural Gas	4	\$/MMBtu
20% of Heat Input	150	MMBtu/hr
Natural Gas Cost	600	\$/hr
NOx Emission Rate	0.5	lb/MMBtu
	375	lb/hr
NOx Removal Rate	0.065625	ton/hr
Fuel Cost per Ton of NOx Removed	9,143	\$/ton

Was the over fire air and staged combustion analysis submitted as part of a BACT analysis for the recent boiler capacity upgrade? Is so, what parts of the Notice of Construction package discuss this analysis and the effects of implementing it? If the analysis was not part of the Notice of Construction package, please supply a copy of the analysis showing the pre change condition and expected improvements resulting from the changes made.

*No, the recently installed overfire air (OFA) system improvements did not undergo BACT analysis. Based on information in the literature and from the OFA system vendor regarding similar projects at comparable boilers, the OFA system was projected to provide an overall NOx emission decrease. BACT analysis was not required, because the No. 11 Boiler Upgrade Project did not cause either a significant increase in emissions of any PSD pollutant, or a short term peak emission rate increase for any air pollutant subject to Washington's New Source Review requirements. A Notice of Construction Application was submitted and approved for the project, but this NOC was for installation of new emission controls (electrostatic precipitator) which improved control of particulate and sulfur dioxide emissions.*

*The purpose of the new OFA system was to improve the system's ability to deliver overfire air into the combustion zone of the boiler. The old system delivered overfire air through a large number of relatively small air ports in the sidewalls at two elevations in the boiler. These ports were ineffective at delivering air to mix with the uncombusted fuel rising up the center of the firebox, because the many small air ports did not provide the momentum necessary to penetrate into the center of the combustion zone. Overfire air tended to channel up the sides of boiler, without providing the desired oxygen distribution or air to fuel mixing. As a result, almost all*

*the combustion air was delivered as undergrate air, with only a small amount directed to the overfire air ports.*

*The new system, designed and installed by Jansen, utilizes fewer, larger air ports equipped with jet nozzles capable of forcing overfire across the width of the boiler, providing effective mixing and delivering air to where it is needed in the core of the firebox.*

*The Boiler Upgrade project was completed in September, 2006. Since then, boiler operations staff has continued efforts to optimize the boiler's combustion system performance to meet targets for increased boiler utilization (offsetting natural gas firing in other boilers), improving response to steam demand swings, and improving NO<sub>x</sub> emission performance.*

*New system performance summary:*

*OFA Flow:*

<i>Pre-Project Baseline OFA Flow:</i>	<i>44 KPPH</i>
<i>Post-Project OFA Flow:</i>	<i>140 KPPH</i>

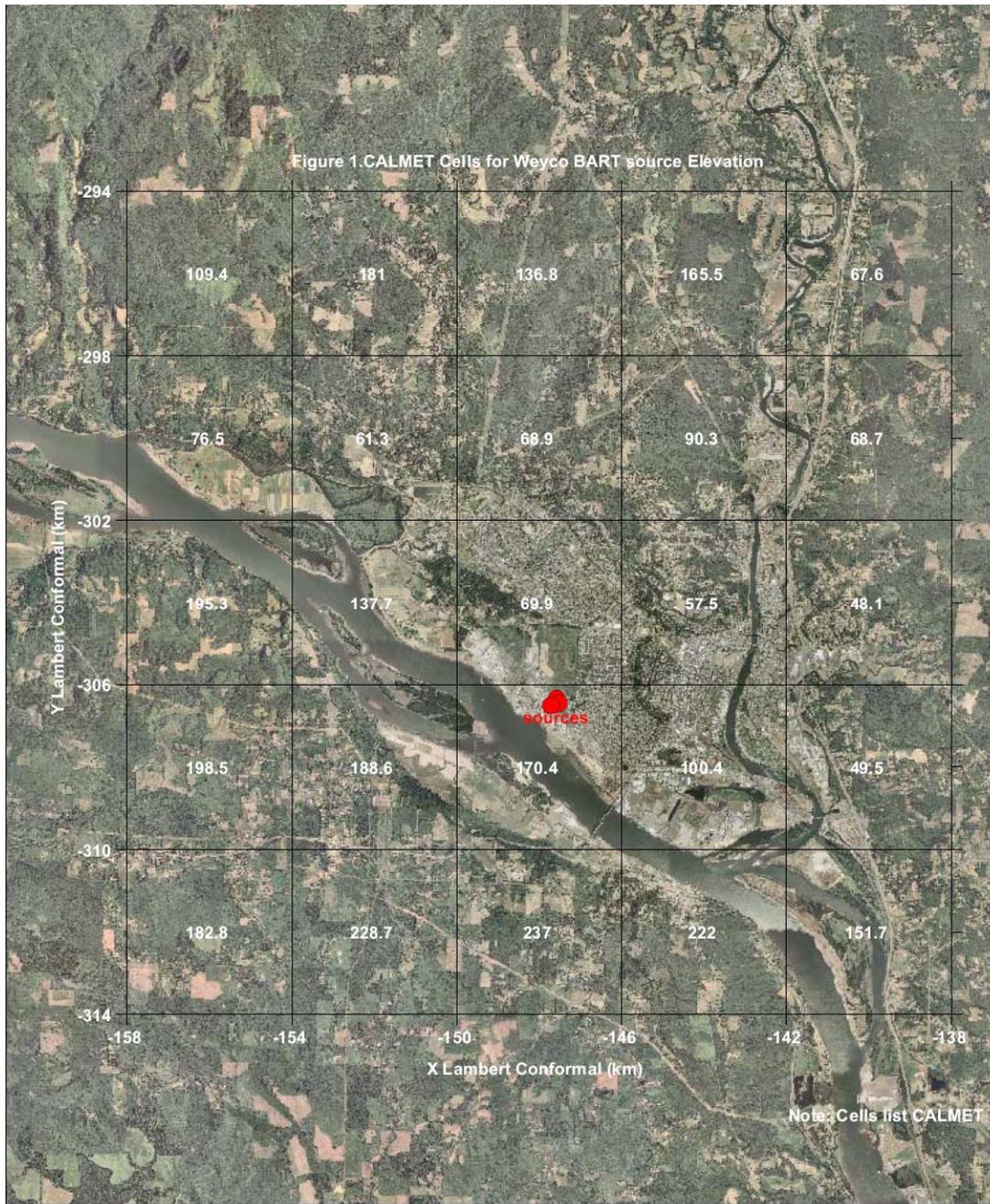
*NO<sub>x</sub> Performance:*

<i>Pre-Project Baseline:</i>	<i>0.53 lb/mmbtu</i>
<i>Projected post-project emissions rate:</i>	<i>0.40 lb/mmbtu</i>
<i>2007 actual, First full year after project completion:</i>	<i>0.51 lb/mmbtu</i>
<i>2008 actual, Year to date, through 5/28/08:</i>	<i>0.43 lb/mmbtu</i>

15. Table 6, page 23. We note that the stack base elevation shown is 17 -18 feet for all stacks. According to the BART modeling protocol, the modeled terrain elevation should be used, not an actual elevation. The BART modeling terrain elevation at the plant site is 99 meters. If there is a need to remodel the impacts from the facility, the 99 meter site elevation must be used. One reason to remodel the impacts would be to reflect corrections to the apparent error in the recovery furnace maximum 24 hour SO<sub>2</sub> emission rate.

*BART source elevations are assigned based the sources Lambert conformal coordinates and the elevation those coordinates would have in the CALMET domain grid. This interpretation is based on the guidance provided in the BART protocol issued by the tri states of Oregon, Washington and Idaho (October, 2006).*

*The attached figure shows which grid the sources fall in and the elevations for surrounding cells in the CALMET domain. The sources should be assigned an elevation of 170.4 meters.*



*The original modeling used the base elevation of 69.9 meter, which is the elevation of the grid just to the north of the sources and more representative of the area around the sources.*

16. As information to support our regional haze SIP, we need to have a copy of the following modeling information:

- a. Input files used for Calpuff, Calpost and, if used, POSTUTILS.
- b. The output (\*.lst) files from Calpuff and Calpost.

- c. A spreadsheet with ranked delta dVs at each Class I area. The spreadsheet needs to include at a minimum, the 8th highest values for each year, and the 22nd highest for all 3 years.
- d. The species contribution to delta dV on the above mentioned 8<sup>th</sup> highest days per Class I area per year, and 22<sup>nd</sup> highest days over the 3 year period for each Class I area.

Data for (c) and (d) are available in the Calpost output files. The information can be supplied on CD's or a DVD.

*Will be provided in revised BART Analysis Report*

- 17. We want a copy of the BART analysis (and any updates or modifications resulting from the above comments) in electronic form for posting on our web site and to ease distribution to non-Ecology reviewers.

*Will be provided in revised BART Analysis Report*