# Prevention of Significant Air Quality Deterioration Review

## Preliminary Determination

February 2009

Facility Name: Yellow Pine Energy Company, LLC
City: Fort Gaines
County: Clay
AIRS Number: 06100001
Application Number: 17700
Date Application Received: October 1, 2007

Review Conducted by:
State of Georgia - Department of Natural Resources
Environmental Protection Division - Air Protection Branch
Stationary Source Permitting Program

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# SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Yellow Pine Energy Company, LLC (Yellow Pine) for a permit to construct and operate a 110-megawatt (MW) biomass-fired power plant. The proposed project was to include: fluidized bed boiler(s) with a total heat input capacity of 1,529 million British Thermal Units per hour ($10^6$ Btu/hr); a condensing steam turbine generator; an auxiliary boiler with a heat input capacity of 25 x $10^6$ Btu/hr; multi-cell mechanical draft wet cooling tower; a water treatment plant; a wastewater treatment plant and outfall; a back-up emergency diesel generator and diesel firewater pump; ash/inert landfill; aqueous ammonia storage tank; limestone storage bins; a No. 2 fuel oil storage tank; diesel fuel oil storage tanks; and supporting plant equipment. In the original application, the plant would have the capability of firing bituminous coal, petroleum coke (pet coke), or 95% metal-free tire-derived fuel (TDF) in small quantities in addition to biomass fuel. However, subsequent Yellow Pine submittals to EPD indicate that the plant will now have the capability of firing only 95% metal-free tire-derived fuel (TDF) in small quantities in addition to biomass fuel. In addition, the original application indicated the possibility of installing one or two fluidized bed boilers to obtain the required heat input capacity. Based on recently submitted additional information (August 1, 2008 Yellow Pine Submittal to EPD), Yellow Pine proposes to install one boiler to obtain the heat input capacity needed to run the plant. Low sulfur No. 2 fuel oil or propane is proposed for use at start-up of the fluidized bed boiler and as the primary fuel of the auxiliary boiler.

The construction of Yellow Pine will result in emissions of Nitrogen Oxides ($NO_x$), Sulfur Dioxide ($SO_2$), Carbon Monoxide (CO), Volatile Organic Compound (VOC), Particulate Matter with an aerodynamic size equal to or less than 2.5 microns ($PM_{2.5}$) and Particulate Matter with an aerodynamic size equal to or less than ten microns ($PM_{10}$) above the applicable Prevention of Significant Deterioration (PSD) significance levels (SLs).

Yellow Pine will be located in Clay County, which is classified as “attainment” or “unclassifiable” for $SO_2$, $PM_{2.5}$ and $PM_{10}$, $NO_X$, CO, and ozone (VOC).

The EPD review of the data submitted by Yellow Pine related to the proposed plant indicates that the project will be in compliance with all applicable state and federal air quality regulations.

It is the preliminary determination of the EPD that the proposal provides for the application of Best Available Control Technology (BACT) for the control of $NO_x$, $SO_2$, CO, VOC, $PM_{10}$, and $PM_{2.5}$ as required by federal PSD regulation 40 CFR 52.21(j) and 40 CFR 51.165 (for $PM_{2.5}$).

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment in the area surrounding the facility or in Class I areas located within 300 km of the facility. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Yellow Pine to construct and operate a 110-MW biomass-fired power plant. A copy of the draft permit is included in Appendix A.

# 1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

On October 1, 2007, Yellow Pine Energy Company, LLC (hereafter Yellow Pine) submitted an application for an air quality permit to construct and operate a 110-megawatt (MW) biomass-fired power plant. The facility is located at Georgia Highway 39 in Fort Gaines, Clay County.

Based on the proposed project description and data provided in the permit application and CH2M Hill's November 30, 2007 letter, the estimated emissions of regulated pollutants from the facility are listed in Table 1-1 below:

**Table 1-1: Emissions from the Project**

| Pollutant | Potential Emissions (tpy) | PSD Significant Emission Rate (tpy) | Subject to PSD Review |
|---|---|---|---|
| PM | 222 | 25 | Yes |
| $PM_{10}$ | 222 | 15 | Yes |
| VOC | 194 | 40 | Yes |
| $NO_X$ | 670 | 40 | Yes |
| CO | 2,009 | 100 | Yes |
| $SO_2$ | 670 | 40 | Yes |
| TRS | 0 | 10 | No |
| Pb | 0.7 | 0.6 | Yes |
| Fluorides | $2.53 \times 10^{-2}$ | 3 | No |
| $H_2S$ | 0 | 10 | No |
| Sulfuric acid mist | 67 | 7 | Yes |

The emissions calculations for Table 1-1 can be found in detail in the facility's PSD application (see Section 4 and Appendix E of Application No. 17700). Since the initial submittal of this data, Yellow Pine has revised its proposed fuel usage. Therefore, the facility should no longer be considered PSD significant for fluorides, lead, or sulfuric acid mist.

Based on the information presented in Table 1-1 and subsequent permit application modifications, Yellow Pine, as specified per Georgia Air Quality Application No. 17700, is classified as a major modification under PSD because the potential emissions of $NO_x$, $SO_2$, CO, VOC, $PM_{10}$, and $PM_{2.5}$.

Through its new source review procedure, EPD has evaluated Yellow Pine's proposal for compliance with State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination. Table 1-2 indicates potential emissions of select PSD/NSR pollutants from the proposed fluidized bed boiler, the major source of the facility's emissions, after the Division's Review and determination of PSD limits.

**Table 1-2: Select Emissions from the Proposed Fluidized Bed Boiler**

| Pollutant | Potential Emissions (tpy) |
|---|---|
| PM | 121 |
| $PM_{10}$ | 121 |
| VOC | 140 |
| $NO_X$ | 670 |
| CO | 998 |
| $SO_2$ | 67 |
| TRS | 0 |
| Pb | 0.20 |

# 2.0 PROCESS DESCRIPTION

According to Application No. 17700, Yellow Pine has proposed to construct and operate a 110-megawatt (MW) biomass-fired power plant to generate electricity for sale. The plant will have the capability of firing 95% metal-free tire-derived fuel (TDF) in small quantities in addition to biomass fuel. Low sulfur No. 2 fuel oil or propane will be used for start-up of the fluidized bed boiler and will be the primary fuel of the auxiliary boiler.

The proposed project will include:

- A fluidized bed boiler with a heat input capacity of 1,529 million British Thermal Units per hour ($10^6$ Btu/hr);
- one 210-foot exhaust stack that will exhaust the products of combustion from the fluidized bed boiler;
- air pollution controls on the fluidized bed boiler that include:
    - Selective Non-Catalytic Reduction
    - Dry Scrubber System
    - Fabric Filter Baghouse;
- condensing steam turbine generator (Application 17700 is silent about the capacity of this equipment);
- auxiliary boiler with a heat input capacity of 25 x $10^6$ Btu/hr;
- one 100-foot exhaust stack for the auxiliary boiler;
- mechanical draft wet cooling towers (multi-cell units) (Application 17700 is silent about the number and capacity this equipment);
- water intake structures in the Chattahoochee River and an on-site pond (Application 17700 is silent about the number and capacity this equipment);
- water treatment plant (Application 17700 is silent about the capacity this facility);
- cooling tower water and boiler feed water make-up systems (Application 17700 is silent about the number and capacity this equipment);
- wastewater treatment plant and outfall in the Chattahoochee River (Application 17700 is silent about the capacity of this facility);
- ash/inert landfill (Application 17700 is silent about the capacity of this facility);
- ash pneumatic truck loading station (Application 17700 is silent about the capacity this equipment);
- barge terminal in the Chattahoochee River, crane and conveyers (Application 17700 is silent about the number and capacity this equipment);
- two (2) open-air and covered fuel storage areas, one on the river side and one on the highway side (Application 17700 is silent about the capacity these areas);
- truck dumps, scales, stack-out/reclaim systems (Application 17700 is silent about the number and capacity this equipment);
- outdoor electrical switchyard (Application 17700 is silent about the number and capacity this equipment);
- tank for aqueous ammonia storage for the selective non-catalytic reduction;
- water storage tanks (Application 17700 is silent about the number and capacity of this equipment);
- limestone storage bins (Application 17700 is silent about the number and capacity of this equipment);
- No. 2 fuel oil storage tank;
- Diesel fuel oil storage tanks for on-site mobile equipment and emergency systems;
- backup emergency generator and firewater pump;
- paved and unpaved plant roads and parking areas; and
- miscellaneous maintenance buildings/sheds, control room, laboratory and office site (Application 17700 is silent about the capacity of these facilities).

The Yellow Pine permit application and supporting documentation of this Preliminary Determination and can be found online at www.georgiaair.org/airpermit.

# 3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

## State Rules

*Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1)* requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Georgia Rule 391-3-1-.03(8)(b) continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

*Georgia Rule 391-3-1-.02(2)(b) Emission Limitations and Standards Visible Emissions* limits opacity to less than forty (40) percent, except as may be provided in other more restrictive or specific rules or subdivisions of *Georgia Rule 391-3-1-.02(2).* This limitation applies to direct sources of emissions such as stationary structures, equipment, machinery, stacks, flues, pipes, exhausts, vents, tubes, chimneys or similar structures. This regulation is applicable to the silos, cooling towers, sample testing laboratory, and fuel processing buildings, material handling equipment, and other supporting equipment with the capability of emitting particulates.

*Georgia Rule 391-3-1-.02(2)(d) Emission Limitations and Standards Fuel Burning Equipment* limits particulate emissions from fuel burning equipment. For fuel burning equipment equal to or greater than 10 million British Thermal Units (Btu) heat input per hour, and equal to or less than 250 million Btu heat input per hour, allowable particulate emissions shall be calculated using the following equation:

$P = 0.5\ [10/R]^{0.5}$ pounds per million BTU heat input,

Where:

P = allowable weight of emissions of fly ash and/or other particulate matter in pounds per million Btu heat input
R = heat input of fuel-burning equipment in million Btu per hour.

This emission limit is applicable to the auxiliary boiler. Allowable particulate matter emissions from the auxiliary boiler are approximately 0.32 pounds per hour at maximum firing rate.

For fuel burning equipment with a heat input greater than 250 million BTU heat input per hour, allowable particulate emissions are 0.10 pounds per million BTU heat input. This particulate emission limit is applicable to the fluidized bed boiler.

This regulation also limits the opacity of which is equal to or greater than twenty (20) percent except for one six minute period per hour of not more than twenty-seven (27) percent opacity. This opacity limit is applicable to both the fluidized bed boiler and the auxiliary boiler.

For fuel burning equipment with a heat input greater than 250 million BTU heat input per hour, Nitrogen Emissions are limited as follows:

- when firing coal--0.7 pounds of $NO_X$ per million BTUs of heat input;
- when firing oil--0.3 pounds of $NO_X$ per million BTUs of heat input;
- when firing gas--0.2 pounds of $NO_X$ per million Btus of heat input;

- when different fuels are burned simultaneously in any combination the applicable standard, expressed as pounds of $NO_X$ per million BTUs of heat input, shall be determined by proration. Compliance shall be determined by using the following formula:

  [x(0.20) + y(0.30) + z(0.70)] x + y + z

  where:

  x = percent of total heat input derived from gaseous fuel;
  y = percent of total heat input derived from oil;
  z = percent of total heat input derived from coal.

This limit would apply to the fluidized bed boiler, if firing any of the above referenced fossil fuels as the primary fuels. However, Yellow Pine proposes to fire only fuel oil or propane during startup. Therefore the $NO_x$ emission limitation associated with this regulation is not applicable to the proposed fluidized bed boiler.

*Georgia Rule 391-3-1-.02(2)(e) Emission Limitations and Standards Particulate Emission from Manufacturing Processes* limits particulate emissions from manufacturing processes as follows:

$E = 4.1\ P^{0.67}$; for process input weight rate up to and including 30 tons per hour.
$E = 55\ P^{0.11} - 40$; for process input weight rate above 30 tons per hour.

This regulation is applicable to the silos, cooling towers, and fuel processing buildings, material handling equipment, and other supporting equipment with the capability of emitting particulate matter.

*Georgia Rule 391-3-1-.02(2)(g) Emission Limitations and Standards Sulfur Dioxide* requires that new fuel-burning sources capable of firing fossil fuel(s) at a rate exceeding 250 million BTUs per hour heat input not emit sulfur dioxide equal to or exceeding 0.8 pounds of sulfur dioxide per million BTUs of heat input derived from liquid fossil fuel or derived from liquid fossil fuel and wood residue. This limitation is applicable to the fluidized bed boiler.

All fuel burning sources below 100 million BTUs of heat input per hour shall not burn fuel containing more than 2.5 percent sulfur, by weight. This limit is applicable to the auxiliary boiler, firewater fuel pump, and emergency generator.

Notwithstanding the limitations on sulfur content of fuels stated in paragraph 2. in *Georgia Rule 391-3-1-.02(2)(g)*, sulfur content can be allowed to be greater than that allowed in paragraph 2. in *Georgia Rule 391-3-1-.02(2)(g)*, provided that the source utilizes sulfur dioxide removal and the sulfur dioxide emission does not exceed that allowed by paragraph 2. in *Georgia Rule 391-3-1-.02(2)(g)*, utilizing no sulfur dioxide removal.

*Georgia Rule 391-3-1-.02(2)(n) Emission Limitations and Standards Fugitive Dust* requires Yellow Pine to take all reasonable precautions to prevent such dust from becoming airborne for any operation, process, handling, transportation or storage facility which may result in fugitive dust. This regulation also limits opacity from such sources to less than 20 percent.

This limit applies to paved and unpaved plant roads and parking areas, and material handing equipment.

*Georgia Rule 391-3-1-.02(2)(3) Emission Limitations and Standards Sampling*
This regulation specifies testing requirements and operating conditions during such testing. This regulation is applicable to all required testing of applicable equipment.

*Georgia Rule 391-3-1-.02(2)(4) Emission Limitations and Standards Ambient Air Standards*
This regulation limits the quantities of sulfur dioxide, particulate matter, carbon monoxide, ozone, lead, and nitrogen dioxide from the Yellow Pine facility which would cause the ambient air concentrations listed to be exceeded. The limits are as follows:

- Sulfur Dioxide.
    - The concentration of sulfur dioxide at ground level for any three-hour period shall not exceed 1300 micrograms per cubic meter for more than one such three-hour period per year.
    - The concentration of sulfur dioxide at ground level for any twenty-four hour period shall not exceed 365 micrograms per cubic meter for more than one such twenty-four hour period per year.
    - The annual arithmetic mean concentration of sulfur dioxide at ground level shall not exceed 80 micrograms per cubic meter.
    - Standard conditions for sulfur dioxide measurements shall be considered to be 25 degrees Centigrade ($^oC$) and 760 millimeters in mercury (mm Hg). The specific standard procedure for measuring ambient air concentrations for all sulfur dioxide will be West-Gaeke or equivalent method.
- Particulate Matter.
    - $PM_{10}$
        - The concentration of $PM_{10}$ in the ambient air for any 24-hour period shall not exceed 150 micrograms per cubic meter for more than one such 24-hour period per year. The standard is attained when the expected number of days per calendar year with a 24-hour average concentration above 150 micrograms per cubic meter, as determined in accordance with Appendix K of 40 CFR Part 50 is equal to or less than 1.
        - The annual arithmetic mean concentration of $PM_{10}$ in the ambient air shall not exceed 50 micrograms per cubic meter. The standard is attained when the expected annual arithmetic mean concentration, as determined in accordance with Appendix K of 40 CFR Part 50 is less than or equal to 50 micrograms per cubic meter.
        - $PM_{10}$ shall be measured in the ambient air as $PM_{10}$ (particles with an aerodynamic diameter less than or equal to a nominal ten micrometers) by a reference method based upon 40 CFR Part 50, Appendix J.

- $PM_{2.5}$

  - The concentration of $PM_{2.5}$ (particles with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers) in the ambient air for any 24- hour period shall not exceed 35 micrograms per cubic meter for more than one such 24-hour period per year. The standard is attained when the $98^{th}$ percentile 24-hour concentration as determined in accordance with Appendix N of 40 CFR part 50 is less than or equal to 35 micrograms per cubic meter.

  - The annual arithmetic mean concentration of $PM_{2.5}$ in the ambient air shall not exceed 15 microgram per cubic meter. The standard is attained when the expected annual arithmetic mean concentration, as determined in accordance with Appendix N of 40 CFR part 50 is less than or equal to 15 micrograms per cubic meter.

  - $PM_{2.5}$ shall be measured in the ambient air as $PM_{2.5}$ by reference method based upon 40 CFR Part 50, Appendix L.

- Carbon Monoxide.

  - Carbon monoxide concentration, at ground level, shall not be allowed to exceed 40 milligrams per cubic meter for a one-hour average or 10 milligrams per cubic meter for an eight-hour average. Standard conditions for carbon monoxide measurements shall be considered to be $25^{o}C$ and 760 mm Hg.

  - The specified standard procedure for measuring ambient air concentrations of carbon monoxide shall be the non-dispersive infrared or equivalent method.

- Ozone.

  - The 8-hour ambient air standard for ozone is 0.08 parts-per-million, daily maximum 8-hour average. The standard is attained when the average of the annual fourth-highest daily maximum 8-hour average ozone concentration is less than or equal to 0.08 parts per million, as determined in accordance with appendix I of 40 CFR Part 50.

  - The specific standard procedure for measuring ambient air concentrations of ozone shall be the Chemiluminescence or equivalent method.

- Lead.

  - The mean concentration of lead at ground level shall not exceed 1.5 micrograms per cubic meter averaged over a calendar quarter.

  - The specified standard procedure for measuring ambient air concentrations of lead shall be those required to comply with Federal law or other Federal authority.

- Nitrogen Dioxide.

  - The annual arithmetic mean concentration of nitrogen dioxide at ground level shall not exceed 100 micrograms per cubic meter. Standard conditions for nitrogen dioxide considered to be $25^{o}C$ and 760 mm Hg.

- o The specified standard procedure for measuring ambient air concentrations of nitrogen dioxide shall be the Chemiluminescence or equivalent method.

This does not exempt Yellow Pine from controlling its emissions to a point equal to or lower than the levels required to comply with a specific emission standard enumerated in other sections of the Georgia Rules.

*Georgia Rule 391-3-1-.02(2)(10) Emission Limitations and Standards Chemical Accident Prevention Procedures* applies to any stationary source and to the owner or operator of any stationary source subject to any requirement under 40 CFR Parts 68, as amended. This regulation applies to aqueous ammonia storage as discussed later in this document.

*Georgia Rule 391-3-1-.02(2)(12) Emission Limitations and Standards Clean Air Interstate Rule $NO_x$ Annual Trading Program*

This regulation applied to any source and the owner and operator of any such source subject to any requirements under 40 Code of Federal Regulations Part 96 Subparts AA through HH as amended. This regulation is applicable to the fluidized boiler discussed later in this document. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the federal Clean Air Interstate Rule (CAIR) in its entirety. On November 17, 2008 the United States EPA filed a reply in support of its petition for rehearing in the Clean Air Interstate Rule case. On December 28, 2008, the U.S. Court of Appeals has remanded the CAIR rule without vacatur. Therefore, this rule will remain in place until EPA updates this court's decision.

*Georgia Rule 391-3-1-.02(2)(13) Emission Limitations and Standards Clean Air Interstate Rule $SO_2$ Annual Trading Program*

This regulation applies to any source and the owner and operator of any such source subject to any requirements under 40 Code of Federal Regulations Part 96 Subparts AAA through HHH as amended. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the federal Clean Air Interstate Rule (CAIR) in its entirety. On November 17, 2008 the United States EPA filed a reply in support of its petition for rehearing in the Clean Air Interstate Rule case. On December 28, 2008, the U.S. Court of Appeals has remanded the CAIR rule without vacatur. Therefore, this rule will remain in place until EPA updates this court's decision.

## Federal Rule - PSD

The regulations for PSD in 40 CFR 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply to any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or to all other sources having potential emissions of 250 tons per year or more of any regulated pollutant. They also apply to any modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

In accordance with current EPD guidance, particulate matter emissions with an aerodynamic diameter less than or equal to 2.5 microns are assumed to equal particulate matter emissions with an aerodynamic diameter less than or equal to 10 microns. Therefore, discussion related to these pollutants will be discussed under one heading for this permit, however $PM_{10}$ emissions are potentially regulated under 40 CFR 52.21 while $PM_{2.5}$ emissions are regulated under 40 CFR 51.165.

Georgia has adopted a regulatory program for PSD permits, which the Unites States Environmental Protection Agency (EPA) has approved as part of Georgia's State Implementation Plan (SIP). This regulatory program is located in the Georgia Rules at 391-3-1-.02(7). This means that Georgia EPD issues PSD permits for new major sources pursuant to the requirements of Georgia's regulations. It also means that Georgia EPD considers, but is not legally bound to accept, EPA comments or guidance. A commonly used source of EPA guidance on PSD permitting is EPA's Draft October 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting (NSR Workshop Manual). The NSR Workshop Manual is a comprehensive guidance document on the entire PSD permitting process.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements:

- Application of BACT for each regulated pollutant that would be emitted in significant amounts;
- Analysis of the ambient air impact;
- Analysis of the impact on soils, vegetation, and visibility;
- Analysis of the impact on Class I areas; and
- Public notification of the proposed plant in a newspaper of general circulation

## Definition of BACT

The PSD regulation requires that BACT be applied to all regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case, EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS). In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose and enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

EPA's NSR Workshop Manual includes guidance on the 5-step top-down process for determining BACT. In general, Georgia EPD requires PSD permit applicants to use the top-down process in the BACT analysis, which EPA reviews. The five steps of a top-down BACT review procedure identified by EPA per BACT guidelines are listed below:

Step 1: Identification of all control technologies;
Step 2: Elimination of technically infeasible options;
Step 3: Ranking of remaining control technologies by control effectiveness;
Step 4: Evaluation of the most effective controls and documentation of results; and
Step 5: Selection of BACT.

The following is a discussion of the applicable federal rules and regulations pertaining to the equipment that is the subject of this preliminary determination, which is then followed by the top-down BACT analysis.

## Federal Rule - New Source Performance Standards

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart A – General Provisions*
Except as provided in Subparts B and C of 40 CFR Part 60, the provisions of this regulation apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility [40 CFR 60.1(a)]. Yellow Pine is a new facility with several pieces of equipment and/or processes subject to this regulation. Any new or revised standard of performance promulgated pursuant to Section 111(b) of the Clean Air Act apply to Yellow Pine's applicable equipment and/or processes and any applicable source/equipment for which the construction or modification of is commenced after the date of publication in 40 CFR Part 60 of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that equipment and/or processes [40 CFR 60.1(b)].

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart Da – Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*
The regulation is applicable to each electric utility steam generating unit that is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour) heat input of fossil fuel (either alone or in combination with any other fuel), was constructed, modified, or reconstructed after September 18, 1978[40 CFR 60.40Da (a)]. Yellow Pine proposes to burn low sulfur fuel oil or propane, fossil fuels for startup only. EPD believes that the startup burners' heat input capacity is well below the 250 x $10^6$ Btu/hr. Therefore, EPD believes that the proposed fluidized bed boiler will not be capable of combusting fossil fuel at the applicable capacity, and has been determined that the proposed fluidized bed boiler is not subject to this regulation.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*
This regulation applies to each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) [40 CFR 60.40b(a)]. Any affected facility that meets the applicability requirements and is subject to 40 CFR Part 60 Subpart Ea, 40 CFR Part 60 Subpart Eb, or 40 CFR Part 60 Subpart AAAA of is not covered by this subpart [40 CFR 60.40b(h)]. Although 40 CFR Part 60 Subpart Eb is potentially applicable to the proposed fluidized bed boiler, it is exempted from this regulation as discussed below. Therefore, Yellow Pine's proposed fluidized bed boiler is subject to 40 CFR Part 60 Subpart Db.

This regulation limits $SO_2$ emissions from an affected facility. Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of 40 CFR 60.42b, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential $SO_2$ emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input [40 CFR 60.42b(k)(1)]. Except as provided in paragraph (f) of 40 CFR 60.42b, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis [40 CFR 60.42(e)]. Except as provided in paragraph (i) of 40 CFR 60.42b and §60.45b(a), the $SO_2$ emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction [40 CFR 60.42(g)].

This regulation also limits opacity to no greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity from the fluidized bed boiler on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, since it combusts coal, oil, wood, or mixtures of these fuels with any other fuels [40 CFR 60.43b(f)].

Except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5) of 40 CFR 60.43b, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input [40 CFR 60.43b(h)(1)]. Yellow Pine's proposed fluidized bed boiler does not meet the provisions provided in 40 CFR 60.43b(h)(2), (h)(3), (h)(4), or (h)(5), and is therefore subject to this PM limit. The PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction [40 CFR 60.43b(g)].

On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility under this regulation that commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain $NO_X$ (expressed as $NO_2$) in excess a limit of 86 ng/J (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas if the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels [40 CFR 60.44b(k)(1)]. According to §60.41b, annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year. The proposed fluidized bed boiler is only to operate using No. 2 fuel oil during the startup (33MW or approximately 462 x $10^6$ Btu/hr) operating scenario at a maximum of 15 percent the rated heat input (approximately 69 x $10^6$ Btu/hr). Using the proposed startup operating scenario [4.44 x $10^9$ Btu/year actual annual fuel oil capacity and 2.96 x $10^{10}$ Btu/year potential annual fuel oil capacity at startup], the annual capacity factor is approximately 0.15, given a fuel oil heat capacity of 140,000 Btu per gallon of fuel. Using the fluidized bed's potential design heat input capacity (1.34 x $10^{13}$ Btu/year, the annual capacity factor is approximately 2.21 x $10^{-3}$ or 0.22 percent. Therefore the $NO_x$ limitation of this regulation does not apply to the fluidized bed boiler.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*

This regulation is applicable to the proposed auxiliary boiler since the regulation applies to each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British Thermal Units per hour) or less, but greater than or equal to 2.9 MW (10 million British Thermal Units per hour) [40 CFR 60.40c(a)].

According to Application 17700, the auxiliary boiler has a rated heat input capacity of 25 million British Thermal Units per hour ($10^6$ BTU/hr) and will burn No. 2 fuel with a maximum sulfur content of 0.05 percent by weight or propane for fuel. According to 40 CFR 60.41c, *oil* means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil. *Natural gas* means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 [40 CFR 60.41c].

On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, Yellow Pine's auxiliary boiler, which combusts oil, shall not cause to be discharged into the atmosphere any gases that contain sulfur dioxide ($SO_2$) in excess of 215 nanograms per joule (ng/J) (0.50 pounds [lb]/$10^6$BTU) heat input; or, as an alternative, shall not combust oil in the boiler that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to the auxiliary boiler [40 CFR 60.42c(d)]. Compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable for a distillate oil-fired boiler with heat input capacities between 2.9 and 29 MW (10 x $0^6$ and 100 x $10^6$ BTU/hr) [40 CFR 60.42c(h)(1)]. Except as provided in paragraph (h) of 40 CFR 60.42c, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits must be determined on a 30-day rolling average basis [40 CFR 60.42c(g)].

The $SO_2$ emission limits, fuel oil sulfur limits, and percent reduction requirements apply at all times, including periods of startup, shutdown, and malfunction [40 CFR 60.42c(i)]. Only the heat input supplied to the auxiliary boiler from the combustion of coal and oil is counted under § 60.42c. No credit is provided for the heat input to the auxiliary boiler from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns [40 CFR 60.42c(j)].

Neither particulate matter emission standards nor opacity standards of this regulation apply to the auxiliary boiler because its heat input capacity is less than 30 x $10^6$ BTU/hr and the types of fuel burned.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart Eb – Standards of Performance for Large Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994 or for Which Modification or Reconstruction is Commenced After June 19, 1996*

This regulation is applicable to each municipal waste combustor unit with a combustion capacity greater than 250 tons per day of municipal solid waste for which construction, modification, or reconstruction is commenced after September 20, 1994 [40 CFR 60.50b(a)]. Any cofired combustor, as defined in 40 CFR 60.51b, which meets the capacity specifications of the rule is not subject to 40 CFR Part 60, Subpart Eb if the owner or operator of the cofired combustor: (1) Notifies EPA of an exemption claim; (2) Provides a copy of the federally enforceable permit that limits the firing of municipal solid waste to less than or equal to 30 percent of the weight of which is comprised, in aggregate, of municipal solid waste as measured on a calendar quarter basis; and (3) Keeps records of the amount of municipal solid waste combusted at the cofired combustor and the weight of all other fuel combusted at the cofired combustor.[40 CFR 60.50b(j)].

This regulation defines municipal solid waste or municipal-type solid waste or MSW means household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, nonmanufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, nonmedical waste discarded by hospitals, material discarded by nonmanufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional waste does not include used oil; sewage sludge; wood pallets; construction, renovation, and demolition wastes (which includes but is not limited to railroad ties and telephone poles); clean wood; industrial process or manufacturing wastes; medical waste; or motor vehicles (including motor vehicle parts or vehicle fluff). Household, commercial/retail, and institutional wastes include: (1) Yard waste; (2) Refuse-derived fuel; and (3) Motor vehicle maintenance materials limited to vehicle batteries and tires except as specified in §60.50b(g) [40 CFR 60.51b(3)]. Refuse-derived fuel means a type of municipal solid waste produced by processing municipal solid waste through shredding and size classification. This includes all classes of refuse-derived fuel including low-density fluff refuse-derived fuel through densified refuse-derived fuel and pelletized refuse-derived fuel.

According to §60.50b(g), any unit combusting a single-item waste stream of tires is not subject to 40 CFR Part 60, Subpart Eb if the owner or operator of the unit notifies EPA of an exemption claim and provides data documenting that the unit qualifies for this exemption. In relationship to the proposed tire-derived fuel combustion in the fluidized bed boiler, Yellow Pine maintains that the proposed fluidized boiler cannot be exclusively fired on this fuel. The Division has evaluated Yellow Pine's claim that supplemental fuel is required to operate the proposed fluidized bed boiler, and has determined that it is unsubstantiated. In addition, in a letter dated June 17, 2008 from EPD to Yellow Pine, the Division requested that Yellow Pine provide the specifications of the proposed 95 percent metal free TDF from a potential vendor to be used in the fluidized boiler. Yellow Pine's response indicated that it cannot currently assure that the specific TDF (95% metal free TDF) will be commercially available to meet Yellow Pine's needs. Therefore, per EPD's letter dated November 12, 2008, Yellow Pine will be permitted to burn TDF on a trial burn basis only to determine its impact on emissions and whether its use is advantageous from an operational standpoint as Yellow Pine claims. Yellow Pine will have a federally enforceable limit restricting TDF combustion during the trial burn to less than 15 percent on a Btu basis for the fluidized bed boiler. Yellow Pine is required to notify EPA as described above of potential applicability of 40 CFR Part 60, Subpart Eb to the fluidized bed boiler.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984*

Except as provided in paragraph (b) of 40 CFR 60.110b, this regulation applies is each storage vessel with a capacity greater than or equal to 75 cubic meters ($m^3$) (19,813 gallons [gal]) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984[40 CFR 60.110b(a)]. According to § 60.111b, a VOL means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere. Volatile organic compounds (VOC) means any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions [40 CFR 51.100(s)].

The following tanks are potentially subject this regulation:

- 100,000-gallon No. 2 Fuel Oil Storage Tank,
- 5,000-gallon Diesel Fuel Storage Tank,

- 25,000-gallon Ammonia (19% aqueous) Storage Tank,
- 500-gallon Diesel Fuel Storage Tank,
- 250-gallon Diesel Fuel Storage Tank, and
- 250-gallon Diesel Fuel Storage Tank.

The 5,000-gallon Diesel Fuel Storage Tank, 500-gallon Diesel Fuel Storage Tank, and the two (2) 250-gallon Diesel Fuel Storage Tanks are exempted from this regulation due to their size capacity. The 25,000-gallon Ammonia (19% aqueous) Storage Tank is also exempt from this regulation, as it does not store a VOL as defined above.

This subpart does not apply to storage vessels with a capacity greater than or equal to 151 $m^3$ (39,890 gallons) storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 $m^3$ (19,813 gallons) but less than 151 $m^3$ storing a liquid with a maximum true vapor pressure less than 15.0 kPa [40 CFR 60.110b(b)]. The 100,000-gallon No. 2 Fuel Oil Storage Tank meets this exemption. Therefore this regulation is not applicable to any the facility storage tanks listed in Application 17700.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants*

This regulation is applicable to the following affected facilities in fixed or portable nonmetallic mineral processing plants: each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station. Also, crushers and grinding mills at hot mix asphalt facilities that reduce the size of nonmetallic minerals embedded in recycled asphalt pavement and subsequent affected facilities up to, but not including, the first storage silo or bin [40 CFR 60.670(a)]. This regulation applies to applicable sources constructed, modified, or reconstructed after August 31, 1983 [40 CFR 60.670(e)]. This regulation is applicable to the following equipment:

- Crushers, grinding mills, screening operations, bucket elevators, belt conveyors, bagging operations, storage bins, enclosed truck or railcar loading stations
- Limestone and sand processing, conveying, and storage equipment.

On and after the date on which the performance test required to be conducted by §60.8 is completed, Yellow Pine shall cause to be discharged into the atmosphere from any transfer point on belt conveyors or from any other affected facility any stack emissions which contain particulate matter in excess of 0.05 g/dscm (0.022 gr/dscf); and exhibit greater than 7 percent opacity, unless the stack emissions are discharged from an affected facility using a wet scrubbing control device [40 CFR 60.672(a)].

On and after the sixtieth day after achieving the maximum production rate at which the applicable equipment will be operated, but not later than 180 days after initial startup as required under §60.11 of this part, Yellow Pine shall not cause to be discharged into the atmosphere from any transfer point on belt conveyors or from any other affected equipment any fugitive emissions which exhibit greater than 10 percent opacity, except as provided in paragraphs (c), (d), and (e) of 40 CFR 60.672 [40 CFR 60.672(b)].

On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under §60.11 of this part, Yellow Pine shall not cause to be discharged into the atmosphere from any crusher, at which a capture system is not used, fugitive emissions which exhibit greater than 15 percent opacity [40 CFR 60.672(c)].

Truck dumping of nonmetallic minerals into any screening operation, feed hopper, or crusher is exempt from the requirements of this section [40 CFR 60.672(d)]. If any transfer point on a conveyor belt or any other affected equipment is enclosed in a building, then each enclosed affected equipment must comply with the emission limits in paragraphs (a), (b) and (c) of section 40 CFR 60.672, or the building enclosing the affected facility or facilities must comply with the following emission limits: (1) Yellow Pine shall not cause to be discharged into the atmosphere from any building enclosing any transfer point on a conveyor belt or any other affected facility any visible fugitive emissions except emissions from a vent as defined in §60.671.(2) Yellow Pine shall not cause to be discharged into the atmosphere from any vent of any building enclosing any transfer point on a conveyor belt or any other affected facility emissions which exceed the stack emissions limits in paragraph (a) of 40 CFR 60.672 [40 CFR 60.672(e)].

On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under §60.11 of this part, Yellow Pine shall not cause to be discharged into the atmosphere from any baghouse that controls emissions from only an individual, enclosed storage bin, stack emissions which exhibit greater than 7 percent opacity [40 CFR 60.672(f)]. Multiple storage bins with combined stack emissions shall comply with the emission limits in paragraph (a)(1) and (a)(2) of 40 CFR 60.672 [40 CFR 60.672(g)].

On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup, Yellow Pine shall not cause to be discharged into the atmosphere any visible emissions from: (1) Wet screening operations and subsequent screening operations, bucket elevators, and belt conveyors that process saturated material in the production line up to the next crusher, grinding mill or storage bin. (2) Screening operations, bucket elevators, and belt conveyors in the production line downstream of wet mining operations, where such screening operations, bucket elevators, and belt conveyors process saturated materials up to the first crusher, grinding mill, or storage bin in the production line [40 CFR 60.672(h)].

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart AAAA –Standards of Performance for Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001*

This regulation is applicable to a municipal waste combustion unit that meets two criteria: (a) the municipal waste combustion unit is a new municipal waste combustion unit, and (b) the municipal waste combustion unit has the capacity to combust at least 35 tons per day but no more than 250 tons per day of municipal solid waste or refuse-derived fuel [40 CFR 60.1010]. A new municipal waste combustion unit is a municipal waste combustion unit that meets either of two criteria: (1) Commenced construction after August 30, 1999, or (2) Commenced reconstruction or modification after June 6, 2001 [40 CFR 60.1015(a)].

Yellow Pine's fluidized boiler would only be subject this regulation if the capacity to combust TDF is less than 250 tons per day. Therefore, Yellow Pine must follow the requirements of 40 CFR Part 60, Subpart Eb, and is not subject to 40 CFR Part 60, Subpart AAAA.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart CCCC – Standards of Performance for Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001*

This regulation is applicable to an incineration unit which meets all the following requirements: (a) the incineration unit is a new incineration unit as defined in §60.2015; (b) the incineration unit is a commercial and industrial solid waste incineration (CISWI) unit as defined in §60.2265; and (c) the incineration unit is not exempt under §60.2020 [40 CFR 60.2010]. A new incineration unit is an incineration unit that meets either (1) Commenced construction after November 30, 1999, or (2) Commenced reconstruction or modification on or after June 1, 2001.

Commercial and industrial solid waste incineration (CISWI) unit means any combustion unit that combusts commercial or industrial waste (as defined in 40 CFR Part 60, Subpart CCCC), that is a distinct operating unit of any commercial or industrial facility (including field erected, modular, and custom built incineration units operating with starved or excess air), and any air curtain incinerator that is a distinct operating unit of any commercial or industrial facility that does not comply with the opacity limits under this subpart applicable to air curtain incinerators burning commercial or industrial waste. While not all CISWI units will include all of the following components, a CISWI unit includes, but is not limited to, the commercial or industrial solid waste feed system, grate system, flue gas system, waste heat recovery equipment, if any, and bottom ash system. The CISWI unit does not include air pollution control equipment or the stack. The CISWI unit boundary starts at the commercial or industrial waste hopper (if applicable) and extends through two areas: The combustion unit flue gas system, which ends immediately after the last combustion chamber or after the waste heat recovery equipment, if any; and the combustion unit bottom ash system, which ends at the truck loading station or similar equipment that transfers the ash to final disposal. The CISWI unit includes all ash handling systems connected to the bottom ash handling system. A CISWI unit does not include any of the fifteen types of units described in §60.2555 of 40 CFR Part 60, Subpart CCCC, nor does it include any combustion turbine or reciprocating internal combustion engine. Commercial or industrial waste means solid waste (as defined in 40 CFR Part 60, Subpart CCCC) that is combusted at any commercial or industrial facility using controlled flame combustion in an enclosed, distinct operating unit: Whose design does not provide for energy recovery (as defined in 40 CFR Part 60, Subpart CCCC); or operated without energy recovery (as defined in 40 CFR Part 60, Subpart CCCC). Commercial or industrial waste also means solid waste (as defined in 40 CFR Part 60, Subpart CCCC) combusted in an air curtain incinerator that is a distinct operating unit of any commercial or industrial facility. *Energy recovery* means the process of recovering thermal energy from combustion for useful purposes such as steam generation or process heating. *Solid waste* means any garbage, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, commercial, mining, agricultural operations, and from community activities, but does not include solid or dissolved material in domestic sewage, or solid or dissolved materials in irrigation return flows or industrial discharges which are point sources subject to permits under section 402 of the Federal Water Pollution Control Act, as amended (33 U.S.C. 1342), or source, special nuclear, or byproduct material as defined by the Atomic Energy Act of 1954, as amended (42 U.S.C. 2014). Since the fluidized boiler will be utilized to provide energy recovery as defined by the regulation, 40 CFR Part 60, Subpart CCCC is not applicable.

Furthermore, in accordance with 40 CFR 60.2020(c)(1), incineration units that are regulated under 40 CFR Part 60 Subpart Ea of this part (Standards of Performance for Municipal Waste Combustors); 40 CFR Part 60 Subpart Eb of this part (Standards of Performance for Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994); 40 CFR Part 60 Subpart Cb (Emission Guidelines and Compliance Time for Large Municipal Combustors that are Constructed on or Before September 20, 1994); 40 CFR Part 60 Subpart AAAA (Standards of Performance for New Stationary Sources: Small Municipal Waste Combustion Units); or 40 CFR Part 60 Subpart BBBB (Emission Guidelines for Existing Stationary Sources: Small Municipal Waste Combustion Units). The fluidized bed boiler will be regulated under 40 CFR Part 60, Subpart Eb as described above.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
This regulation is applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of § 60.4200. For the purposes of this regulation, the date that construction commences is the date the engine is ordered by Yellow Pine [40 CFR 62.4200(a)]. Yellow Pine must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by Yellow Pine that are approved by the engine manufacturer, over the entire life of the engine [40 CFR 60.4206].

Yellow Pine proposes to install a 450 horsepower (Hp) fire pump engine. According to Appendix D of a letter date April 16, 2008 from CH2M Hill acting on behalf of Yellow Pine, the displacement of the proposed fire pump engine will be 14.6 liters. Fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this 40 CFR Part 60, Subpart IIII, for all pollutants [40 CFR 60.4205(c)].

Yellow Pine proposes to install a 1,500 KW emergency generator. In Appendix C of a letter date April 16, 2008 from CH2M Hill acting on behalf of Yellow Pine, the displacement of the proposed engine will be 50.3 liters.

After December 31, 2008, Yellow Pine cannot install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines [40 CFR 60.4208(a)]. After December 31, 2009, Yellow Pine cannot install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines [40 CFR 60.4208(b)]. In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (f) of this §60.4208 after the dates specified in paragraphs (a) through (f) of §60.4208 [40 CFR 60.4208(g)].

Yellow Pine proposes to use diesel fuel in the proposed fire pump and emergency generator engines. Yellow Pine must use diesel fuel that meets the requirements of 40 CFR 80.510(a) [40 CFR 60.4207(a)]. Beginning October 1, 2010, stationary CI ICE subject to 40 CFR Part 60, Subpart IIII with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel [40 CFR 60.4207(b)]. For pre-2011 model year stationary CI ICE subject to 40 CFR Part 60, Subpart IIII, Yellow Pine may petition the Division for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of § 60.4207 beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Division 40 CFR 60.4207(c)]. Table 8 to 4 CFR Part 60, Subpart IIII indicates which parts of the General Provisions in §§60.1 through 60.19 [40 CFR 60.4218].

Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Yellow Pine may petition the Division for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if Yellow Pine maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited [40 CFR 60.4211(e)].

## Federal Rule - National Emissions Standards For Hazardous Air Pollutants

*Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 63) National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart A – General Provisions*
This regulation contains national emission standards for hazardous air pollutants (NESHAP) established pursuant to section 112 of the Act as amended November 15, 1990. These standards regulate specific categories of stationary sources that emit (or have the potential to emit) one or more hazardous air pollutants listed in this part pursuant to section 112(b) of the Act. The standards in this part are independent of NESHAP contained in 40 CFR Part 61. The NESHAP in part 61 promulgated by signature of the Administrator before November 15, 1990 (i.e., the date of enactment of the Clean Air Act Amendments of 1990) remain in effect until they are amended, if appropriate, and added to 40 CFR Part 63 [40 CFR 63.1(a)(1) and (2)]. No emission standard or other requirement established under 40 CFR Part 63 shall be interpreted, construed, or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established by the Administrator pursuant to other authority of the Act (section 111, part C or D or any other authority of this Act), or a standard issued under State authority. The Administrator may specify in a specific standard under this part that facilities subject to other provisions under the Act need only comply with the provisions of that standard. [40 CFR 63.1(a)(3)]. Yellow Pine is a new facility with several pieces of equipment and/or processes subject to this regulation.

*Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 63) National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j)*
The requirements of §§63.40 through 63.44 of 40 CFR Part 63, Subpart B carry out section 112(g)(2)(B) of the 1990 Amendments [40 CFR 63.40(a)]. The requirements of §§63.40 through 63.44 of 40 CFR Part 63, Subpart B apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants after the effective date of section 112(g)(2)(B) (as defined in §63.41) and the effective date of a title V permit program in the State or local jurisdiction in which the major source is (or would be) located unless the major source in question has been specifically regulated or exempted from regulation under a standard issued pursuant to section 112(d), section 112(h), or section 112(j) and incorporated in another subpart of part 63, or the owner or operator of such major source has received all necessary air quality permits for such construction or reconstruction project before the effective date of section 112(g)(2)(B) [40 CFR 63.40(b)].

Fluidized Bed Boiler

The fluidized bed boiler hazardous air pollutant emissions would have been subject to *Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 63) National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart DDDDD- Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters*. However, this regulation was vacated by the District of Columbia (D.C.) Circuit Court of Appeals on June 18, 2007.

The Division requested submittal of a Case-by-Case MACT application for the proposed fluidized bed boiler in a letter dated June 17, 2008. Yellow Pine submitted the requested Case-by-Case MACT application as Appendix B of its August 1, 2008 response to the Division's June 17, 2008 letter. The requirements of this regulation will be addressed in Appendix A of this document.

Auxiliary Boiler

The proposed auxiliary boiler would have been subject to *Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 63) National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart DDDDD- Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters*. However, this regulation was vacated by the District of Columbia (D.C.) Circuit Court of Appeals on June 18, 2007. As a result, the Division requested that Yellow Pine submit a Case-by-Case MACT determination application in accordance with § 63.53. Yellow Pine submitted a case-by-case MACT determination application as Appendix A of its November 30, 2007 letter to the Division. The requirements of this regulation will be addressed in Appendix A of this document.

*Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 63) National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart DD – National Emission Standards for Hazardous Air Pollutants from Off-Site Waste and Recovery Operations*
This regulation applies to the owner and operator of a plant site for which: (1) The plant site is a major source of hazardous air pollutant (HAP) emissions as defined in 40 CFR 63.2, and (2) At the plant site is located one or more of operations that receives off-site materials as specified in paragraph (b) of 40 CFR 63.680 and the operations is one of the waste management operations or recovery operations as specified in paragraphs (a)(2)(i) through (a)(2)(vi) of 40 CFR 63.680 [40 CFR 63.680(a)]. A waste management operation that treats wastewater which is an off-site material and the operation meets both of the following conditions: (1) The operation is subject to regulation under either section 402 or 307(b) of the Clean Water Act but is not owned by a "state" or "municipality" as defined by section 502(3) and 502(4), respectively, of the Clean Water Act; and (2) The treatment of wastewater received from off-site is the predominant activity performed at the plant site[40 CFR 63.680(a)(2)(iii)].

An off-site material is: (1) a waste, used oil, or used solvent as defined in §63.681; (2) the waste, used oil, or used solvent is not produced or generated within the plant site, but the material is delivered, transferred, or otherwise moved to the plant site from a location outside the boundaries of the plant site; and (3) the waste, used oil, or used solvent contains one or more of the hazardous air pollutants (HAP) listed in Table 1 of this subpart based on the composition of the material at the point-of-delivery, as defined in §63.681 [40 CFR 63.680(b)(1)]. Waste means a material generated from industrial, commercial, mining, or agricultural operations or from community activities that is discarded, discharged, or is being accumulated, stored, or physically, chemically, thermally, or biologically treated prior to being discarded or discharged [40 CFR 63.681].

According to Application 17700, Yellow Pine proposes to operate a wastewater treatment facility to treat plant washings and rainwater runoff from open-air storage yards. Since the proposed wastewater treatment plant will not treat an off-site material as defined by this regulation, the proposed wastewater treatment plant is not subject to this regulation.

*Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 63) National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [RICE]*
This regulation is applicable to a stationary RICE as defined in the regulation at a major source of HAP emissions, which is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAPs at a rate of 25 tons (22.68 megagrams) or more per year [40 CFR 63.6585].

Emergency stationary RICE means any stationary RICE whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc. Stationary RICE used for peak shaving are not considered emergency stationary RICE. Stationary ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines [40 CFR 63.6675].

The regulation further stipulates that emergency stationary RICE with a site-rating of more than 500 brake HP located at a major source of HAP emissions that were installed on or after June 12, 2006, must comply with requirements specified in 40 CFR 60.4243(d) [40 CFR 63.6675]. According to 40 CFR 60.4243(d), emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. Emergency stationary ICE may operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity. For owners and operators of emergency engines, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as permitted in this section, is prohibited.

The proposed emergency generator and fire pump engines meet the definition of emergency stationary RICE. An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, or an existing CI stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE, are not required to comply with the emission limitations in Tables 1a and 2a of 40 CFR Part 63, Subpart ZZZZ or operating limitations in Tables 1b and 2b of 40 CFR Part 63, Subpart ZZZZ [40 CFR 63.6600(c)].

## Federal Rule – 40 CFR 64 – Compliance Assurance Monitoring

*Part 64, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 64) Compliance Assurance Monitoring [CAM]*
Except for backup utility units that are exempt under paragraph (b)(2) of 40 CFR 64.2, the requirements of 40 CFR Part 64 apply to a pollutant-specific emissions unit at a major source that is required to obtain a part 70 or 71 permit if the unit satisfies all of the following criteria: (1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under paragraph (b)(1) of 40 CFR 64.2; (2) The unit uses a control device to achieve compliance with any such emission limitation or standard; and (3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. Where "potential pre-control device emissions" has the same meaning as "potential to emit," as defined in §64.1, except that emission reductions achieved by the applicable control device are not taken into account [40 CFR 64.2(a)].

Yellow Pine is required to address 40 CFR Part 64 applicability in its initial Title V Operating Permit application as discussed below.

## Federal Rule – 40 CFR 68 – Chemical Accident Prevention Provisions

*Part 68, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 68) Chemical Accident Prevention Provisions*

This regulation establishes the list of regulated substances and thresholds, the petition process for adding or deleting substances to the list of regulated substances, the requirements for owners or operators of stationary sources concerning the prevention of accidental releases, and the State accidental release prevention programs approved under section 112(r). The list of substances, threshold quantities, and accident prevention regulations promulgated under 40 CFR Part 68 do not limit in any way the general duty provisions under section 112(r)(1) [40 CFR 68.1].

An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under §68.115, must comply with the requirements of this part no later than the date on which a regulated substance is first present above a threshold quantity in a process [40 CFR 68.1(a)(3)]. Process means any activity involving a regulated substance including any use, storage, manufacturing, handling, or on-site movement of such substances, or combination of these activities. For the purposes of this definition, any group of vessels that are interconnected, or separate vessels that are located such that a regulated substance could be involved in a potential release, shall be considered a single process [40 CFR 68.3].

Regulated toxic and flammable substances under section 112(r) of the Clean Air Act are the substances listed in Tables 1, 2, 3, and 4. Threshold quantities for listed toxic and flammable substances are specified in the tables [40 CFR 68.130(a)]. Table 1 of § 68.130 lists anhydrous ammonia with a threshold quantity of 10,000 pounds. The ammonia listing is subject to the one percent de minimis concentration. Thus, mixtures containing total aqueous ammonia at concentrations equal to or in excess of one percent should be factored into threshold determinations[1].

Although Table 4 lists propane a flammable substance, and lists a threshold quantity, propane storage would not be subject to this regulation as it is excluded from all provisions of 40 CFR Part 68 since it is used as a fuel [40 CFR 38.126].

Yellow Pine proposes to use aqueous ammonia in its pollution control equipment as described later in this document. The aqueous ammonia will be stored in a 25,000-gallon storage tank at the facility. Once Yellow Pine has reached the threshold quantity of ammonia, then it must develop and implement a risk management program as specified in the regulation. Facilities subject to the rule must conduct a hazard assessment, compile a 5-year accident history, develop an accident prevention program, develop an emergency response program, and submit risk management information to EPA as specified in the regulation. The requirements of this regulation are not further discussed in this document, as it is not overseen by the Division. However, Yellow Pine must comply with all applicable requirements as specified in the regulation.

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[1] *Emergency Planning and Community Right-to-Know Section 313 Guidance for Reporting Aqueous Ammonia*. United States Environmental Protection Agency Office of Environmental Information Washington, DC 20460, Revised December 2000, EPA 745-R-00-005, page 4.

## Federal Rule – 40 CFR 70 – Title V Operating Permit

*Part 70, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 70) State Operating Permit Programs [Title V]*
The regulations in 40 CFR Part 70 provide for the establishment of comprehensive State air quality permitting systems consistent with the requirements of title V of the Clean Air Act (Act) (42 U.S.C. 7401, *et seq.*). These regulations define the minimum elements required by the Clean Air Act for State operating permit programs and the corresponding standards and procedures by which the Administrator will approve, oversee, and withdraw approval of State operating permit programs. Georgia has an established such a program. Yellow Pine, because it can potentially emit applicable pollutants above the applicable major source thresholds, is subject to 40 CFR Part 70. All sources subject to these regulations must have a permit to operate that assures compliance by the source with all applicable requirements [40 CFR 70.1(b)].

Yellow Pine must prepare and submit an initial Title V Operating Permit Application for the operation of the Yellow Pine facility in accordance with 40 CFR 70.5. The initial Title V application must be submitted within 12 months after Yellow Pine becomes subject to the permit program or on or before such earlier date as the Division may establish [40 CFR 70.5(a)(i)]. Since Yellow Pine is required to meet the requirements under section 112(g) of the Clean Air Act, or to have a permit under the preconstruction review program approved into the applicable implementation plan under part C [PSD] or D [Plan Requirements for Non-Attainment Areas] of Title I of the Clean Air Act, Yellow Pine must file a complete application to obtain the part 70 permit within 12 months after commencing operation or on or before such earlier date as the Division may establish [40 CFR 70.5(a)(ii)]. The Division requires that Yellow Pine submit a complete initial Title V Operating Permit Application within 12 months of commencing operation.

## Federal Rule – 40 CFR 72, 73, 75, 76, and 77 – Acid Rain

*Part 72, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 72) Permits Regulation [Acid Rain]*
Yellow Pine will install one boiler to achieve its required heat input capacity of 1,529 x $10^6$ Btu/hr. The proposed fluidized boiler is subject to the requirements of the Acid Rain Program [40 CFR 72.6(a)(3)(i)]. Therefore, Yellow Pine must meet applicable permit requirements, monitoring requirements, sulfur dioxide ($SO_2$) requirements, nitrogen oxides ($NO_x$) requirements, excess emissions requirements, and liability specifications as specified in 40 CFR 72.9. Yellow Pine must follow all provisions specified in 40 CFR Part 72 Subparts A through I.

The regulations also set forth requirements for obtaining three types of Acid Rain permits, during Phases I and II, for which an affected source may apply: Acid Rain permits issued by the United States Environmental Protection Agency during Phase I; the Acid Rain portion of an operating permit issued by a State permitting authority during Phase II; and the Acid Rain portion of an operating permit issued by EPA when it is the permitting authority during Phase II.

According to this regulation, *fossil fuel-fired* means the combustion of fossil fuel or any derivative of fossil fuel, alone or in combination with any other fuel, independent of the percentage of fossil fuel consumed in any calendar year (expressed in mmBtu) [40 CFR 72.2]. *Fossil fuel* means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material [40 CFR 72.2]. Based on these definitions and the proposed fuel usage of the boiler as indicated in Application 17700 and associated additional submittals, the fluidized boiler will be classified as f*ossil fuel-fired*.

*Part 73, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 73) Sulfur Dioxide Allowance System*

The regulation requires owners, operators, and designated representatives of affected sources and affected units pursuant to §72.6 and as specified in 40 CFR Part 73. This regulation establishes the requirements and procedures for the following: (1) The allocation of sulfur dioxide emissions allowances; (2) The tracking, holding, and transfer of allowances; (3) The deduction of allowances for purposes of compliance and for purposes of offsetting excess emissions pursuant to parts 72 and 77 of Chapter I; (4) The sale of allowances through EPA-sponsored auctions and a direct sale, including the independent power producers written guarantee program; and (5) The application for, and distribution of, allowances from the Conservation and Renewable Energy Reserve; and (6) The application for, and distribution of, allowances for desulfurization of fuel by small diesel refineries [40 CFR 73.1]. Yellow Pine's proposed fluidized bed boiler is subject to 40 CFR Part 73.

*Part 75, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 75) Continuous Emissions Monitoring*

The purpose of this regulation is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide ($SO_2$), nitrogen oxides ($NO_X$), and carbon dioxide ($CO_2$) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to sections 412 and 821 of the CAA, 42 U.S.C. 7401–7671q as amended by Public Law 101–549 (November 15, 1990) [the Act]. In addition, this regulation sets forth provisions for the monitoring, recordkeeping, and reporting of $NO_X$ mass emissions with which EPA, individual States, or groups of States may require sources to comply in order to demonstrate compliance with a $NO_X$ mass emission reduction program, to the extent these provisions are adopted as requirements under such a program. Yellow Pine must follow all provisions specified in 40 CFR Part 75 Subparts A through I. The proposed fluidized bed boiler is classified as a fossil fuel-fired boiler. However, in accordance with § 75.12 (f), the owner or operator of an affected unit that combusts wood, refuse, or other material in addition to oil or gas shall comply with the monitoring provisions specified in paragraph (a) of 40 CFR 75.12.

*Part 76, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 76) Acid Rain Nitrogen Oxides Emission Reduction Program*

Except as provided in paragraphs (b) through (d) of § 76.1, the provisions apply to each coal-fired utility unit that is subject to an Acid Rain emissions limitation or reduction requirement for $SO_2$ under Phase I or Phase II pursuant to sections 404, 405, or 409 of the Clean Air Act [40 CFR 76.1(a)]. A coal-fired utility unit means a utility unit in which the combustion of coal (or any coal-derived fuel) on a Btu basis exceeds 50.0 percent of its annual heat input during the following calendar year: for Phase I units, in calendar year 1990; and, for Phase II units, in calendar year 1995 or, for a Phase II unit that did not combust any fuel that resulted in the generation of electricity in calendar year 1995, in any calendar year during the period 1990–1995. For the purposes of this part, this definition shall apply notwithstanding the definition in §72.2 [40 CFR 76.2]. Based on this definition, the proposed bubbling bed fluidized boiler will not be subject to the emission limits in 40 CFR Part 76; however, the boiler will be subject to the continuous monitoring of $NO_x$ emissions required under 40 CFR Part 75.

*Part 77, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 77) Excess Emissions*

This regulation sets forth the excess emissions offset planning and offset penalty requirements under section 411 of the Clean Air Act, 42 U.S.C. 7401, *et seq.,* as amended by Public Law 101–549 (November 15, 1990). These requirements shall apply to the owners and operators and, to the extent applicable, the designated representative of each affected unit and affected source under the Acid Rain Program. Nothing in 40 CFR Part 77 will limit or otherwise affect the application of sections 112(r)(9), 113, 114, 120, 303, 304, or 306 of the Clean Air Act, as amended. Any allowance deduction, excess emission penalty, or interest required under 40 CFR Part 77 will not affect the liability of the affected unit's and affected source's owners and operators for any additional fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the Clean Air Act. Yellow Pine's fluidized boiler must comply as applicable with this regulation.

**Federal Rule – 40 CFR 96 – Clean Air Interstate Rule [CAIR]**

*Part 96, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 96) Subpart AA – Clean Air Interstate Rule [CAIR] $NO_x$ Annual Trading Program General Provisions, Subpart BB – CAIR Designated Representative for CAIR $NO_x$ Sources, Subpart CC – Permits, Subpart EE - CAIR $NO_x$ Allowance Allocations, Subpart FF – CAIR NOx Allowance Tracking System, Subpart GG – CAIR $NO_x$ Allowance Transfers, Subpart HH – Monitoring and Reporting*

These regulations established the model rule comprising general provisions and the designated representative, permitting, allowance, and monitoring provisions for the State Clean Air Interstate Rule (CAIR) $NO_X$ Annual Trading Program, under section 110 of the Clean Air Act and §51.123 of Chapter I, as a means of mitigating interstate transport of fine particulates and nitrogen oxides. The owner or operator of a unit or a source was to comply with the requirements of these regulations as a matter of federal law only if the State with jurisdiction over the unit and the source incorporated by reference such subparts or otherwise adopted the requirements of such subparts in accordance with §51.123(o)(1) or (2) of Chapter I, the State submitted to the Administrator one or more revisions of the State implementation plan that included such adoption, and the Administrator approved such revisions. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated CAIR in its entirety. On November 17, 2008 the United States EPA filed a reply in support of its petition for rehearing in the Clean Air Interstate Rule case. On December 28, 2008, the U.S. Court of Appeals has remanded the CAIR rule without vacatur. Therefore, this rule will remain in place until EPA updates this court's decision. However, since the rule becomes applicable only when Yellow Pine becomes an operational facility, its applicability will not be addressed by this permit.

*Part 96, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 96) Subpart AAA – Clean Air Interstate Rule [CAIR] SO2 Trading Program General Provisions, Subpart BBB – CAIR Designated Representative for CAIR SO2 Sources, Subpart CCC – Permits, Subpart FFF – CAIR $NO_x$ Allowance Tracking System, Subpart GGG – CAIR $NO_x$ Allowance Transfers, Subpart HHH – Monitoring and Reporting*

These regulations established the model rule comprising general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the State Clean Air Interstate Rule (CAIR) $SO_2$Trading Program, under section 110 of the Clean Air Act and §51.124 of Chapter I, as a means of mitigating interstate transport of fine particulates and sulfur dioxide. The owner or operator of a unit or a source was to comply with the requirements of these regulations as a matter of federal law only if the State with jurisdiction over the unit and the source incorporated by reference such subparts or otherwise adopts the requirements of such subparts in accordance with §51.124(o)(1) or (2) of Chapter I, the State submitted to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approved such revisions. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated CAIR in its entirety. On November 17, 2008 the United States EPA filed a reply in support of its petition for rehearing in the Clean Air Interstate Rule case. On December 28, 2008, the U.S. Court of Appeals has remanded the CAIR rule without vacatur. Therefore, this rule will remain in place until EPA updates this court's decision. However, since the rule becomes applicable only when Yellow Pine becomes an operational facility, its applicability will not be addressed by this permit.

**State and Federal – Startup and Shutdown and Excess Emissions**

Excess emissions from applicable equipment may result from a malfunction of the associated control equipment. The facility cannot anticipate or predict malfunctions. However, the facility is required to minimize emissions during periods of startup, shutdown, and malfunction. Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7. These provisions do not apply to sources subject to New Source Performance Standards (NSPS) and some National Emissions Standards for Hazardous Air Pollutants (NESHAP).

Excess emissions from the fluidized boiler stack are most likely to occur during periods of startup and/or shutdown because during these periods operation, operating conditions such as temperature and flow rates of the unit exhaust from the fluidized bed boiler may not conducive to proper operation of applicable control systems, resulting in emissions of applicable pollutants above usual levels. Application 17700 is silent about the operation of applicable control equipment during periods of startup and/or shutdown. EPD requested that Yellow Pine provide such information. In a response letter from CH2M Hill dated April 16, 2008, indicated the following:

- The baghouse will be operational at all times when the boiler is combusting fuel.

- Ammonia injection (for the SNCR) will be injected at the appropriate ratio when there is sufficient heat input to the boiler to sustain optimal temperatures in the hot zone of the boiler (normally 1500 °F to 1600 °F for a Fluidized Bed boiler), which will be monitored in the boiler control room by operators using a thermocouple connected to the boiler control system. During shutdown, when the operator sees that temperatures are below this temperature range, ammonia injection will be discontinued to avoid excess ammonia emissions or "slip" to the atmosphere. It is expected that SNCR operation will begin approximately 4 hours after the beginning of the start-up cycle, which is the period when the start-up burners (on fuel oil or propane) will finish their cycle and biomass in increasing amounts is being fed to the boiler.

- During start-up, the dry scrubbing system will be brought up to temperature when the start-up burners are operating. The injection of limestone/lime will commence when the boiler operating on solid fuels reaches approximately thirty percent of rated fuel input and the steam turbine has sufficient flow to commence its operation. As the whole plant is ramped up, the injection rate for limestone/lime will also ramp up to follow stoichiometric proportions with the fuel. During shutdown, the injection of limestone/lime will be reduced in parallel with fuel consumption.

During start-up and shutdown, the primary concern is fouling of the control devices due to corrosion from the condensation of water vapor and acid gasses (acid dew point), according to CH2M Hill's (acting on behalf of Yellow Pine) April 16, 2008 letter. Therefore, injection of materials into the flue gas stream will require at a minimum that a stable temperature be achieved. Yellow Pine proposed a start-up and shutdown plan be developed with the intent of maximizing the use of the control devices to limit emissions, while at the same time being protective of the control devices. Therefore, within 120 days of issuance of the proposed permit, Yellow Pine must prepare a operation plan for review and approval by the Division that will explicitly detail how long it will take to bring control device(s) online after startup and/or shutdown and how the process will done. This plan must also detail how the control devices will be operated during proposed facility operational loads to ensure proper emissions control.

In its November 30, 2007 response letter to the Division, CH2M Hill acting on behalf of Yellow Pine indicated that the facility is being developed as a base-load facility to run continuously and provide power on a contract basis. The letter indicates that the facility is expected to have two scheduled startup and shutdown sequences per year, one in the spring and one in the fall. Each of these events will be associated with scheduled maintenance and the facility will be shut down for a total of four (4) weeks per year. According to the November 30, 2007 letter, a cold startup of the proposed fluidized boiler can last up to approximately 8 to 14 hours from initial firing, depending on fuel and other conditions, in order to achieve approximately 30% load (33 MW). The time frame may be shortened in some instances by using the auxiliary boiler to preheat the steam turbine. Escalation to 100 percent load could require an additional two (2) to four (4) hours beyond the startup period.

According to the November 30, 2007 letter, Yellow Pine expects the startup of the fluidized bed boiler on 100 percent biomass to be worst-case startup scenario for certain pollutants due to the variable moisture content of the biomass and the potential of incomplete combustion. The letter indicates that startup will normally be initial/supplemented with fuel oil and/or propane, but these periods will be very short and infrequent.

The Division disagrees with the cold startup of the fluidized boiler while combusting 100% biomass due to the potential increase in nitrogen oxides and carbon monoxide emissions. Therefore, the Division requires that Yellow Pine must implore the use of low sulfur fuel oil (at a minimum) or propane during these time frames to reduce the potential increase in nitrogen oxides and carbon monoxide emissions. Although the use of such fuels may result in slightly higher sulfur dioxide emissions, the use of these fuels may result in a reduction of startup time, thus reducing startup emissions overall. In addition, startup for the fluidized bed boiler shall be defined as first firing until 30 percent load or 33 MW is reached and shall last no longer than 14 hours.

Limits established under PSD apply at all times.[2] A PSD BACT limit which is the equivalent of NSPS and/or NESHAP limit subsumes that limit. Therefore, if a PSD BACT limit subsumes any NSPS or NESHAP requirements, excess emissions of the short term (ppm or lb/$10^6$Btu) during startup, shutdown and malfunction are not subject to the provisions in Georgia Rule 391-3-1-.02(2)(a)7. As a result, Yellow Pine must comply with applicable BACT limitations for applicable pollutants during all periods of operation, including startup, shutdown, and malfunction.

[2] http://www.epa.gov/region07/programs/artd/air/nsr/nsrpg.htm - accessed March 1, 2008.

# 4.0 CONTROL TECHNOLOGY REVIEW

The proposed project will result in emissions that are significant enough to trigger PSD review for the following pollutants: $NO_x$, $PM_{10}$, $PM_{2.5}$, $SO_2$, CO, and VOC.

## Fluidized Bed Boiler - Background

The bubbling bed fluidized bed boiler (Source Code FB) was proposed to be manufactured and installed in 2008. According to Application 17700, the boiler was to be designed to be 100% biomass-fired, but also be supplemented with up to 15% of tire-derived fuel, on a heat input basis, or approximately 5% on a weight basis. The biomass will consist of wood wastes in chip or shredded form from timber harvesting, pre-commercial thinning of forest plantation stands, harvesting non-commercial, dead or deformed species for fuel purposes and land clearing activities (limbs, tops, stumps and non-commercial trees), and may also include peanut hulls, pecan shells, cotton stalks, lumber and pallet wood wastes (unpainted/untreated only) and similar woody biomass. The application is based on wood waste from timber harvesting (i.e. green tons).

Yellow Pine will be permitted to conduct a trial burn restricting 95 percent metal free TDF combustion during the trial burn to less than 15 percent on a Btu basis for the fluidized bed boiler. The firing of TDF in the fluidized bed boiler is only authorized for a period up to 30 days from the commencement of operation of the bubbling fluidized bed boiler. The facility will be required to obtain certification records from the supplier for each delivery of TDF to verify the metal content is at or below 95 percent. The facility will also be required to conduct performance tests for all potential applicable pollutants emissions. The performance tests will be used to determine if any potential pollutant is emitted in significant amount when firing 95 percent metal free TDF as well as allow the facility to collect trial data for any future permitting actions.

According to Application 17700, Yellow Pine will not operate below 80 percent load. Therefore, Yellow Pine will be required to operate at no less than 80 percent load, except during periods of startup and/or shutdown where startup is as defined previously in this document.

Start-up of the fluidized bed boiler involves heating the boiler using burners until the fuel auto-ignition temperature is reached. During start-up, the auxiliary boiler will be fired on either low sulfur No. 2 fuel oil or propane and will generate steam to heat the steam turbine. As the system is heated, airflow is introduced into the bottom of the bubbling fluidized bed boiler and sand/limestone is added into the boiler to form a bed. The airflow fluidizes the sand/limestone bed. Exhaust gasses pass through the super-heater and economizer tube bundles to generate steam.

Application 17700 indicates that during periods of biomass/supplemental fuel firing, a sand/limestone bed is used in stoichiometric ratio corresponding to the percent of supplemental fuel, and during periods of 100 percent biomass firing, a sand bed will be used instead of a sand/limestone bed. The Division expressed its concern about the lack of discussion in Application 17700 about monitoring and record keeping ensuring compliance with this operational flexibility. CH2M Hill's response letter, dated January 10, 2008, indicated that Yellow Pine would monitor and record the amount of sand and sand/limestone fed from the day silos to the fluidized bed boiler on an hourly basis (weigh-belt). This response is silent about how Yellow Pine will determine what fuel and/or fuel/combination is being fired at any time. Therefore, Yellow Pine must always operate a sand/limestone bed when firing any fuel and/or fuel combination in the fluidized bed boiler.

Fluidized Bed Boiler – Nitrogen Oxides ($NO_x$) Emissions

Nitrogen Oxides ($NO_x$) are formed during the combustion of the fuel and are generally classified as either thermal $NO_x$, prompt $NO_x$ or fuel-related $NO_x$. Thermal $NO_x$ results when atmospheric nitrogen is oxidized at high temperatures to yield nitric oxide (NO), nitrogen dioxide ($NO_2$), and other oxides of nitrogen. Most thermal $NO_x$ is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce a peak temperature. Prompt $NO_x$ forms within the combustion flame and is usually negligible when compared to the amount of thermal $NO_x$ formed. Fuel-related $NO_x$ is formed from the chemically bound nitrogen in the fuel.

Care must be taken when incorporating design changes to reduce both NOx and carbon monoxide emissions. Carbon monoxide emission combustion modifications can possibly increase NOx emissions and vice versa. A balance between these air pollutants must be achieved in order for combustion modification to be useful.

Applicant's Proposal

*Step 1: Identify all control technologies*

In Application 17700, Yellow Pine evaluated pre and post combustion control technologies for the FB. The pre-combustion control technologies evaluated, verbatim as described in Application 17700, are as follows:

- Fuel Selection – Nitrogen is one of the elements contained in biomass, coal, pet coke, and TDF. The amount of nitrogen in a particular fuel is variable. For biomass and TDF, the nitrogen content is generally less than 1 percent on a dry basis and for coal and pet coke is generally less than 2 percent. The boiler will normally be fired on up to 100% biomass, with the potential to fire up to 15% coal, pet coke or TDF by heat input. Since biomass has a lower nitrogen content than coal and pet coke. Fuel $NO_X$ can be reduced by burning a secondary fuel that contains less nitrogen content like TDF. In practice, because the fossil fuel component is so small, the secondary fuel selection will be based on more significant parameters, such as sulfur content and fuel heating value, and in consideration of the economic and logistic factors associated with the delivery of the fuel to the site. Furthermore, the substitution of a secondary fuel that has less nitrogen content may cause an increase in other types of emissions.

- Low $NO_x$ Burners (LNB) – Low $NO_X$ burners limit $NO_X$ formation by controlling both the stoichiometric and temperature profiles of the combustion process. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen ($O_2$) in the primary combustion zone, reduced flame temperature and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower $NO_X$ emissions during the combustion process.

- Rotating Opposed Fire Air (ROFA) – The ROFA design injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA differs from OFA in that ROFA utilizes a booster fan to increase the velocity of air to promote better mixing and to increase the retention time in the furnace. A modification of the ROFA process is RotaMix in which urea or ammonia is injected with ROFA.

- Natural Gas Reburning (NGR) – NGR is a combustion control technology in which part of the main fuel heat input is diverted to locations above the main burners, thus creating a secondary (or reburn) fuel, natural gas, which is injected to produce a slightly fuel rich reburn zone. Overfire air is added above the reburn zone to complete burnout of the reburn fuel. As fuel gas passes through the reburn zone, part of the $NO_X$ formed in the main combustion zone is reduced by hydrocarbon fragments (free radicals) and converted to molecular nitrogen.

- Fuel Lean Gas Reburning (FLGR) – FLGR, also known as controlled gas injection, is a process in which careful injection and controlled mixing of natural gas into the furnace exit region reduces $NO_X$. The gas is normally injected into a lower temperature zone than in NGR. Whereas NGR requires 15 to 20 percent of furnace heat input from gas and requires burnout air, the FLGR technology achieves $NO_X$ control using less than 10 percent gas heat input and no burnout air. Less $NO_X$ reduction is achieved with FLGR when compared with NGR.

- Advanced Gas Reburning (AGR) – AGR adds rich compound (typically urea or ammonia) downstream of the reburning zone. The reburning system is adjusted for somewhat lower $NO_X$ reduction to produce free radicals that enhance the selective non-catalytic $NO_X$ reduction. AGR systems can be designed in two ways: (1) non-synergistic, which is essentially the sequential application of NGR and selective non-catalytic reduction (i.e., the nitrogen agent is injected with a second burnout air stream). To obtain maximum $NO_X$ reduction and minimum reagent slip in non-synergistic systems, the nitrogen agent must be injected so that it is available for reaction with furnace gases within a temperature zone around 1800°F.

- Amine Enhanced Gas Injection (AEGI) – AEGI is similar to AGR, except that burn out air is not used, and the selective non-catalytic reduction reagent and reburn fuel are injected to create local, fuel-rich $NO_X$ reduction zones in an overall fuel-lean furnace. The fuel-rich zone exists in local eddies, as in FLGR, with the overall furnace in an oxidizing condition; however, the reduction reagent participates with natural gas (or other hydrocarbon fuel) in a $NO_X$ reduction reaction.

- Induced Flue Gas Recirculation (IFGR) – IFGR recirculates boiler flue gas from the boiler outlet to the furnace where it is reintroduced into the combustion process. Fuel/air mixing in the combustion region is intensified by the recirculated flue gas when introduced into the flame during the early stages of combustion. This intensified mixing offsets the decrease in flame temperature and results in $NO_X$ levels that are lower than those achieved without IFGR. The level of $NO_X$ reduction is dependent upon the burner and furnace design. An additional benefit of IFGR is the potential to lower CO emissions.

- Combustion Controls – As is the case with other types of boilers, combustion control (combustion air staging) is the most cost-effective means for reducing $NO_X$ emissions from FB boilers. Combustion air staging is accomplished by introducing combustion air at two or more levels in the combustion section. Primary air is distributed through an air distributor plate to fluidize the bed. The amount of primary air is maintained below the stoichiometric requirement. Thus, the fuel is initially combusted under rich conditions, which inhibit the formation of $NO_X$ in two ways. First, the amount of oxygen available to oxidize fuel and nitrogen is minimized, minimizing the potential for the oxidation reaction. Second, the concentration of hydrogen-free radicals is increased. These radicals react with some of the $NO_X$ reducing it to nitrogen.

Secondary air is introduced several levels above the bed in the freeboard area. The secondary air brings the total amount of combustion air up to the level needed to achieve good combustion efficiency and minimize emissions of CO and hydrocarbons. The amount of secondary combustion air and the time between primary and secondary air injection is important for minimizing $NO_X$ formation. There are practical limits on how much secondary air can be introduced and how high in the freeboard area the secondary air can be introduced without reducing combustion efficiency, causing corrosion, and lowering steam temperature. The effectiveness of $NO_X$ reduction from combustion air staging is deceased by incomplete combustion, which results in high levels of unburned carbon, CO, and hydrocarbons. Incomplete combustion also decreases the combustion efficiency, increases the amount of fuel consumed, and increases the solid waste volume due to the increased carbon content of the ash.

The post-combustion control technologies evaluated, verbatim as described in Application 17700, are as follows:

- Selective Catalytic Reduction (SCR) – SCR is a control technique that uses ammonia to react with the $NO_X$ in the flue gas at the appropriate temperature in the presence of a catalyst to form water and nitrogen. SCR has two well-documented environmental impacts associated with it, ammonia emissions (sometimes called ammonia slip) and disposal of spent catalyst. Some ammonia emissions from an SCR system are unavoidable because of imperfect distribution of the reacting gases, and ammonia injection control limitations as well as a partially degraded catalyst that results in an incomplete reaction of the available ammonia with $NO_X$. The $NO_X$ removal efficiency of an SCR system depends on the ratio of ammonia to $NO_X$. Therefore, increasing the amount of ammonia injected increases the control efficiency but also increases the amount of unreacted ammonia that is emitted to the atmosphere. Ammonia emissions from a well-controlled SCR system can likely be limited to 10 ppmv or less. Ammonia emissions are of concern, because ammonia is a significant contributor to regional secondary particulate formation and visibility degradation. In this case reduced $NO_X$ emissions as an environmental benefit would be traded for increased ammonia emissions as an environmental cost.

  The other environmental impact associated with SCR is disposal of the spent catalyst. Some of the catalyst used in SCR systems must be replaced every three to five years. These catalysts contain heavy metals including vanadium pentoxide. Vanadium pentoxide is an acute hazardous waste under the Resource Conservation and Recovery Act (RCRA), Part 261, Subpart D – Lists of Hazardous Materials. This must be addressed when handling and disposing of the spent catalyst.

  For a FB boiler, the SCR system would have to be located between the last convection section and the economizer, where optimal temperatures are present. Proper placement of the catalyst would significantly increase the cost of the boiler because the convective heat transfer area would have to be divided. SCR also affects the overall plant operation, because $NH_3$ and $SO_3$ in the flue gas react to form ammonium sulfate and bisulfate upstream of other environmental controls and flue gas handling equipment. Ammonium salt deposition is known to damage these controls and equipment and frequent cleaning is necessary, resulting in increased maintenance costs and unit down time. Additionally, because the SCR system is located upstream of the economizer and air heater, any changes to the boiler operations, such as increased load or excess air, will alter flue gas temperatures at the catalyst bed and can significantly affect both boiler and SCR performance. Important operating and design factors associated with SCR include catalyst deactivation, problems with unreacted $SO_3$ and $NH_3$, and process control limitations.

Catalyst deactivation is the loss of active catalyst sites necessary to promote the $NH_3/NO_X$ reaction. Catalyst deactivation primarily occurs via four mechanisms: poisoning, fouling, thermal degradation, and mechanical losses. Because the SCR system would also be located upstream of a baghouse, mechanical losses and fouling have the potential to be significant problems with catalyst life due to the high dust/particulate load in the flue gas. The catalyst may be permanently poisoned as a result of metals and trace elements in the fuel. These compounds react with the active acid sites on the SCR catalyst surface, thus poisoning the catalyst. The ash material from fluidized bed boilers using limestone injection for $SO_2$ control typically contains 20 to 30 percent calcium oxide.

- Selective Non-Catalytic Reduction (SNCR) – Similar to SCR, SNCR is a post-combustion control method. With the SNCR method a reagent, usually aqueous ammonia or urea, is injected into the hot thermal oxidizer zone just past the combustion zone. The reaction of this reagent with the $NO_X$ present in the products of combustion is driven by the high temperatures within the combustion chamber. No catalyst is used with the SNCR method. The SNCR method is temperature dependent and has a very small temperature window.

  The performance of SNCR is sensitive to flue gas temperature because optimal $NO_X$ reduction occurs in a limited temperature window. In addition, adequate residence time at this temperature is necessary to complete the reactions. Flue gas temperatures fluctuate in the bed, the solids disengagement zone, and in the bypass sections of the fluidized bed boilers when there are changes in boiler load, fuel consumption, and combustion air temperature or flow. Because of this variability, the flue gas at the reagent injection point will not always be at the optimum temperature for $NO_X$ reduction.

  Below the SNCR operating temperature range, the $NH_3/NO_X$ reaction will not occur, and the unreacted $NH_3$ will either be emitted as $NH_3$ slip, or it will react with $SO_3$ to form ammonium salts, or will be incorporated in the ash. Above the optimal temperature, the amount of $NH_3$ that oxidizes to $NO_X$ increases and the $NO_X$ reduction performance deteriorates rapidly. At temperatures at or above 1,900°F, unreacted $NH_3$ emissions decrease due to the $NH_3$ oxidation to $NO_X$. At temperatures at or below 1,800°F, unreacted $NH_3$ emissions increase. Maximum $NO_X$ removal and minimum $NH_3$ slip can be achieved by injecting urea at 1,900°F.

  Fluidized bed boilers typically operate with bed temperatures in the range of 1,500 to 1,600°F to maximize in-bed $SO_2$ control and limit thermal $NO_X$ formation. This lower operating temperature reduces uncontrolled $NO_X$ emissions relative to a PC coal boiler. For boilers requiring high (90 percent or higher) $SO_2$ removal using limestone injection, bed and solids disengagement section temperatures are below optimal for high $NO_X$ reductions and low $NH_3$ slip using SNCR. However, in this case, because of the high biomass fuel usage, in-bed $SO_2$ removal is not much of a factor. Therefore, the FB boiler with SNCR may not be able to achieve the highest end potential $NO_X$ reductions; biomass fuel (i.e. lower fuel nitrogen), lower boiler temperature and higher ammonia slip compensate to achieve a very low $NO_X$ emission level on a cost-effective basis.

  An important operating concern with SNCR is the reaction of $SO_3$ and unreacted $NH_3$ in the flue gases to form ammonium sulfate ($(NH_4)_2SO_4$) and ammonium bisulfate ($(NH_4HSO_4$). During combustion, a small percentage of $SO_2$ will be oxidized to $SO_3$. The $SO_3$ reacts with free $NH_3$ and water to form ammonium sulfates. Ammonium sulfates can condense on the cold end of the air heater and cause fouling. These deposits can cause a significant pressure drop across the air heater. Unfortunately, air soot blowing is often ineffective at removing the ammonium salt deposits. As a result, water washing is often necessary to remove the sticky, water-soluble material. Therefore, the boiler's air heater must be constructed of materials that can tolerate possible corrosion by the liquid waste and must be designed to accommodate water washing. Since the air heater must be cleaned with the boiler off-line, ammonium salt deposits can cause unplanned outages.

Ammonium sulfates can also cause fouling of baghouse fabric filters. These deposits can cause a significant pressure drop across the baghouse. As the pressure drop increases, the boiler capacity will reduce because the boiler fans will not be able to maintain design combustion air flows at the higher baghouse pressure drop.

- Hybrid Selective Reduction (HSR) – HSR is a combination of SNCR and SCR that is designed to provide the performance of full SCR with significant lower costs. In HSR, a SNCR system is used to achieve some $NO_X$ reduction and to produce a controlled amount of ammonia slip that is used in a downstream in-duct SCR reactor for additional $NO_X$ reduction.

- $SCONO_x$® – $SCONO_X$ is catalyst technology developed by Goal Line Environmental Technologies. The technology uses precious metal catalyst to simultaneously convert $NO_X$ and CO to $CO_2$, $H_2O$, and $N_2$. The catalyst must be periodically removed from service for regeneration. This requirement necessitates multiple catalyst sections and additional ductwork and dampers for isolation. Hydrogen diluted with steam is used to regenerate the catalyst and produce a stream of $H_2O$ and $N_2$ that is vented to the stack.

- $THERMALONO_X$® – The $THERMALONO_X$ technology has been developed by Thermal Engineering International as an option for the control of $NO_X$ emissions. The technology is based on the oxidation of NO to $NO_2$ and then dissolving the $NO_2$ in water. The $THERMALONO_X$ technology is intended for use with a wet flue gas desulfurization (FGD) system used for $SO_2$ emission control. The NO oxidation is accomplished by injecting elemental phosphorous into the flue gas stream in a gas reactor installed upstream of the wet FGD absorber. The $NO_2$ becomes dissolved in the wet FGD absorber and can be removed as elemental $N_2$ or various phosphate compounds that may be used as fertilizer and/or animal food additive.

- Electro-Catalytic Oxidation (ECO) – ECO is a multi-pollutant control technology that simultaneously controls PM, $SO_2$, and $NO_X$ along with mercury and hydrochloric acid. The Powerspan Corporation is the developer of the ECO technology. The ECO process includes a conventional dry electrostatic precipitator followed by a reactor that oxidizes the gaseous pollutants. A wet electrostatic precipitator then captures the oxidized pollutants.

- Pahlman Process – The Pahlman process is a multi-pollutant control technology that simultaneously controls $NO_X$ and $SO_2$. Enviroscrub Technologies, the developer of the Pahlman technology, has not been willing to release much information regarding the technology but it has advertised that the technology does not require catalyst or ammonia to accomplish emission reduction.

*Step 2: Eliminate technically infeasible options*

Yellow Pine determined that the following control options are technically infeasible as discussed verbatim as described in Application 17700 below:

- Fuel Selection – The boiler will be primarily fired on biomass. The type of secondary fuel used in the boiler will be selected on the basis of the cost of the fuel delivered to the site and on significant fuel characteristics, such as sulfur content and heating value, each of which strongly affects the design and cost of the boiler and air pollution control equipment. Because nitrogen is present in biomass, coal, pet coke, and TDF only in small amounts and there are many other means available to control $NO_X$ emissions, the selection of fuel on the basis of nitrogen content in favor of the more important parameters listed above is not reasonable. For these reasons, selection of a fuel for the purpose of controlling $NO_X$ is considered technically infeasible and will not be considered further in this application.

- Rotating Opposed Fire Air (ROFA) – ROFA and Rotamix are not mature technologies ready for commercial installation. They have only one commercial installation on a bituminous unit in which ROFA was installed in 2000 and modified for Rotamix in 2002. Recent literature on the process discusses only the one installation and does not provide compatibility with biomass, sub-bituminous coal, pet coke, and TDF firing. For these reasons, ROFA and Rotamix are considered technically infeasible and will not be considered further in this application.

- Natural Gas Reburning (NGR) – NGR has been demonstrated to reduce $NO_X$ emissions by 39 to 67 percent on several existing coal-fired boilers in applications ranging from 33 MW to 600 MW in the United States and up to 800 MW overseas. However, the combustion of natural gas in the reburn zone is not consistent with the project objective of primarily combusting biomass (renewable energy) and the absence of a natural gas pipeline in the area to supply natural gas. In addition, NGR is not listed as a control device for $NO_X$ emissions from either biomass or coal-fired boilers in the RBLC database. Therefore, NGR is considered technically infeasible and will not be considered further in this application.

- Fuel Lean Gas Reburning (FLGR) – FLGR has been demonstrated to reduce $NO_X$ emissions by 33 to 45 percent on several existing coal-fired boilers. The most recent application has been part of a combination FLGR and SNCR demonstration on a 198 MW coal-fired boiler. However, the combustion of natural gas in the furnace exit region is not consistent with the project objective of primarily combusting biomass (renewable energy). In addition, FLGR is not listed as a control device for $NO_X$ emissions from either biomass or coal-fired boilers in the RBLC database. Therefore, FLGR is considered technically infeasible and will not be considered further in this application.

- Advanced Gas Reburning (AGR) – AGR has been applied to a 105 MW coal-fired boiler in the United States and a 285 MW coal-fired boiler in Europe. The projects demonstrated $NO_X$ emissions reductions range from 50 to 76 percent; however ammonia slip in one application could not be reduced below 10 ppm. In the non-synergistic scenario, natural gas is injected in the reburning zone. In the synergistic scenario, the nitrogen agent is injected in the furnace gas around a temperature of 1800°F. This temperature is significantly higher than the expected boiler exit temperature and the $NO_X$ removal efficiency will be greatly degraded at the lower temperature. In addition, AGR is not listed as a control device for $NO_X$ emissions from either biomass or coal-fired boilers in the RBLC database. Additionally, the injection of natural gas in the furnace exit region is not consistent with the project objective of primarily combusting biomass (renewable energy). Therefore, AGR is considered technically infeasible and will not be considered further in this application.

- Amine Enhanced Gas Injection (AEGI) – AEGI has been demonstrated to reduce $NO_X$ emissions by 30 to 73 percent during full-scale commercial applications. However, the combustion of natural gas is not consistent with the project objective of primarily combusting biomass (renewable energy). In addition, AEGI is not listed as a control device for $NO_X$ emissions from either biomass or coal-fired boilers in the RBLC database. Therefore, AEGI is considered technically infeasible and will not be considered further in this application.

- Induced Flue Gas Recirculation (IFGR) – IFGR has been demonstrated as a $NO_X$ reduction technology on smaller natural gas and oil-fired boilers. The applicability of this technology is limited due to the technical complications associated with recirculating the volume of hot, ash-laden flue gas that is generated by a FB boiler. The primary complication is the significant operations and maintenance issues that would result. In addition, IFGR is not listed as a control device for $NO_X$ emissions form either biomass or coal-fired boilers in the RBLC database. Therefore, IFGR is considered technically infeasible and will not be considered further in this application.

- Selective Catalytic Reduction (SCR) – SCR is a proven technology for the reduction of $NO_X$ emissions for typical boilers. However, FB boilers using limestone injection for $SO_2$ control typically contain 20 to 30 percent CaO. The high alkali metal and calcium content of the FB boiler ash is the major reason that SCR emission control technology has not been applied to FB boilers using limestone injection. The alkali metals and CAO are a catalyst poison and greatly reduce the life and effectiveness of the catalyst. Therefore, SCR is considered technically infeasible and will not be considered further in this application.

- Hybrid Selective Reduction (HSR) – HSR has been demonstrated to reduce $NO_X$ emissions by 50 to 98 percent on a 320 MW coal-fired boiler. It is possible the technology can be scaled down to the size of the proposed project. However, HSR is not listed as a control device for $NO_X$ emissions from either biomass or coal-fired boilers in the RBLC database. Therefore, HSR is considered technically infeasible and will not be considered further in this application.

- $SCONO_x$® – $SCONO_X$ technology has not been demonstrated on the flue gas generated by coal combustion. It has only been demonstrated on gas-fired combined cycle power plants. In addition, the presence of $SO_2$ in the flue gas has the potential to poison the $SCONO_X$ catalyst, limiting its effectiveness and its useful life. $SCONO_X$ is not a suitable $NO_X$ emissions control technology for the proposed boiler. Therefore, $SCONO_X$ is considered technically infeasible and will not be considered further in this application.

- $THERMALONO_X$® – $THERMALONO_X$ technology has been installed and tested on flue gas from a coal fired-boiler. The purpose of the test was to demonstrate a $NO_X$ reduction of 75 percent. The less than expected results of the first commercial operation prompted the host utility to halt testing of the technology until further laboratory testing could be completed. $THERMALONO_X$ is an immature technology and is not yet commercially available. Therefore, $THERMALONO_X$ is considered technically infeasible and will not be considered further in this application.

- Electro-Catalytic Oxidation (ECO) – ECO was installed and successfully demonstrated as a pilot system to treat 2,000 to 4,000 SCFM of flue gas generated by a coal-fired boiler. The results of the demonstration showed a $NO_X$ emission reduction of up to 90%. Powerspan is currently working with the host utility to install a larger 50 MW commercial demonstration facility. This demonstration facility was scheduled to be ready for commercial operation in early 2003; however, no published results of the demonstration have been located. ECO is an immature technology and is not commercially available. Therefore, ECO is considered technically infeasible and will not be considered further in this application.

- Pahlman Process – The Pahlman process has been demonstrated in small scale testing to remove in excess of 90 percent of the $NO_X$ emissions and 99 percent of the emissions from the flue gas generated by coal-fired boilers. However, the trailer mounted demonstration system is capable of only treating approximately 1,000 SCFM of flue gas. Enviroscrub Technologies plans to have a larger unit available for commercial testing by the end of 2002, however, no published results of the demonstration have been located. The Pahlman process is an immature technology and is not commercially available. Therefore, Pahlman process is considered technically infeasible and will not be considered further in this application.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

Application 17700's ranking of remaining control technologies by control effectiveness is nonexistent.

*Step 4: Evaluating the Most Effective Controls and Documentation*

Application 17700's evaluation of the most effective controls is nonexistent.

*Step 5: Selection of BACT*

According to Application 17700, the proposed BACT for the FB boiler(s) includes combustion controls and SNCR capable of achieving $NO_X$ emissions of 0.10 lb/$10^6$Btu.

EPD Review – $NO_x$ Control
The Division has determined that Yellow Pine's proposal to use combustion controls and SNCR only to minimize the emissions of $NO_x$ does not constitute BACT.

*Step 1: Identify all control technologies*

In addition to the proposed technologies listed in Application 17700, the following technology was reviewed by the Division.

- Regenerative Selective Catalytic Reduction (RSCR®) - Babcock Power Environmental has designed Regenerative Selective Catalytic Reduction® technology that combines the Regenerative Thermal Oxidizer (RTO) and Selective Catalytic Reduction (SCR) technologies. The result is a $NO_x$ (nitrogen oxides) control system designed especially for tail-end, low temperature applications. This product is capable of greater than 80% $NO_x$ removal.

Further, the Division requested that Yellow Pine review the potential applicability of this control technology.

*Step 2: Eliminate technically infeasible options*

Yellow Pine eliminated fuel selection as technically infeasible. The Division does not agree with this assessment. Fuel selection is technically feasible as $NO_x$ emissions can be controlled by the type of fuel burned in the proposed boilers, because fuels selected with higher heating values could reduce the amount of thermal NOx as a result of allowing more efficient combustion of the biomass fuel. Application 17700 indicates that the supplemental fuel that will be used in the fluidized boilers in addition to the biomass is based on cost. However, no cost analysis was provided for this potential control technology. Nor was any information provided about its potential control efficiency. Therefore, the Division could not fully evaluate its potential as a viable control technology.

The Division also believes elimination of SCR as a potential control technology as a technically infeasible is incorrect. The reason that Yellow Pine provided for eliminating the SCR is based solely on its proposed choice for sulfur dioxide ($SO_2$) control, which is inappropriate when determining BACT for $NO_x$.

The Division contacted a major boiler manufacturer that is capable of manufacturing large fluidized boilers with the input capacity Yellow Pine proposes for its fluidized bed boiler. When asked if the reason Yellow Pine cited for determining SCR infeasible (alkali metals and CAO are a catalyst poison and greatly reduce the life and effectiveness of the catalyst) was a valid statement, the boiler manufacturer representative indicated that this was not correct. According the representative, fluidized bed boilers can be designed so that they can be controlled by SCR.[3]

[3] February 20, 2008 phone conversation with Mike Maryamchick, Circulating Fluidized Bed Boilers technical contact of The Babcock & Wilcox Company.

Evidence of this can be found in the proposed new emissions control system for the Deerhaven Unit #2 Power Plant in Gainesville, Florida. Babcock Power Inc. (BPI), based in Danvers, MA, announced on April 30, 2007 that one of its subsidiary companies, Babcock Power Environmental Inc. (BPEI) had been selected by Gainesville Regional Utilities (GRU) to team with CH2M Hill in an agreement for the engineering, procurement, construction and startup (EPC) of its new emissions control system. The new emissions control system includes a selective catalytic reduction designed to achieve 90% $NO_x$ removal efficiency with the specified coal. The project is scheduled for completion in 2008.[4]

In a letter dated February 15, 2008, the Division requested that Yellow Pine, for every pollutant, rank each BACT by efficiency and provide a cost analysis for each technically feasible control technology eliminated based on cost. The cost analyses could not include costs associated with catalyst disposal or any other solid waste disposal; but could be adjusted down for tax incentives, etc. For nitrogen oxides (NOx) BACT, list each proposed BACT and rank them by control efficiency. The Division also requested that Yellow Pine provide a cost analysis for each technically feasible NOx control eliminated on cost as discussed above. For example, Yellow Pine was to perform a cost analysis for selective catalytic reduction (SCR). In the case of SCR, Yellow Pine could not consider the cost of catalyst disposal in its cost analysis, however this may be considered in environmental impacts.

Yellow Pine submitted its cost analysis for the Division's review. In the Division's letter dated November 12, 2008 it indicated that Yellow Pine's cost analysis to add a 'back end' SCR system to the fluidized boiler was rather high. Therefore, it is considered a technically feasible control option.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

The Division has ranked the following technically feasible control technologies:

**Table 4-1: Ranking of Control Technology**

| Control Technology Ranking | Control Technology | Control Efficiency |
|---|---|---|
| 1 | SCR | 70% to 90% |
| 2 | RSCR | 80% |
| 3 | SCNR | 50% to 80% |
| 4 | Fuel Selection | 30% to 50% |
| 5 | Low NOx Burners and Combustion Controls | Baseline |

*Step 4: Evaluating the Most Effective Controls and Documentation*

The Division conducted further review of the RSCR control technology and its applicability to the proposed fluidized bed boiler.

[4] http://www.babcockpower.com/index.php?option=news&task=viewnews&coid=17&sid=99, accessed March 24, 2008.

A Regenerative Selective Catalytic Reduction® technology system was installed December 11, 2007 at the Bridgewater Power Company's 15 net megawatts biomass (forest residuals and whole tree chips) plant located in the Pemigewasset River Valley in central New Hampshire.[5] The first RSCR unit has been in operation since October 2004 on a 16MW wood-fired boiler and has consistently achieved >75% $NO_x$ reduction. The second RSCR has been in operation since December, 2004 on a 50MW wood fired unit.[6]

Although the system is in practice, the facilities' capacities are less than that proposed by Yellow Pine. In addition, it is not known if the proposed technology is capable of controlling $NO_x$ emissions as efficiently when the use of multiple fuels is proposed. The Division could not locate information indicating the use of this technology on larger sources using multiple fuels.

The Division asked Yellow Pine to obtain a quote from Babcock Power Environmental for the installation of a RSCR system in a letter dated November 12, 2008. Yellow Pine submitted a cost analysis in its December 3, 2008 response letter for the installation of an RSCR on the fluidized bed boiler. Yellow Pine estimates a cost of $17,100 per ton of $NO_x$ removal. The Division believes that this cost estimate is inflated.

The Division conducted further cost analysis including incremental cost analysis comparing SNCR and RSCR technologies. As a result, the Division determined that the average cost per ton of $NO_x$ removal and the incremental cost of RSCR versus SNCR per ton of $NO_x$ removal make it economically infeasible. Therefore, the Division believes this control technology is not viable for the proposed fluidized bed boiler.

*Step 5: Selection of BACT*

Given that demonstration of the effectiveness of a SCR system installed on a bubbling fluidized bed boiler has not been proven in practice, the Division has determined that installation of a SNCR system, used in combination with combustion controls, limestone/sand fluidized bed, continuous temperature indicator, $NO_x$ continuous emissions monitoring (CEMs) and low NOx burners shall be considered BACT.

The SNCR and CEMS must be installed in stack for the fluidized bed boiler, and must be operated at all times the fluidized bed boiler is in operation, regardless of the fuel type being combusted. In addition, Yellow Pine must install a temperature indicator in the stack near the outlet the boilers to determine that the boiler is operating at temperature for optimal control efficiency of the post control technology.

The Division has also chosen emission limits of 0.10 lbs/$10^6$Btu (evaluated to equate to 153 lbs/hr, and 670 tons/year) as BACT at the stack outlet. This limit is applicable at all times, including startup and shutdown.

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[5] http://www.babcockpower.com/index.php?option=news&task=viewnews&coid=17&sid=110, accessed March 24, 2008

[6] http://www.babcockpower.com/index.php?option=news&task=viewnews&coid=17&sid=65, accessed March 24, 2008

Combustion controls[7] shall consist of the following for the fluidized bed boiler:

- Good Combustion Technique: Operator Practices – Maintenance of a written site specific operating procedures manual for the boiler in which operating procedures, including startup, shutdown, and malfunction are well documented in accordance with the manufacturer's specifications. The operating procedures must be updated as applicable with any equipment or operating practice changes. The procedures shall contain operating logs documenting such changes and any deviations from the operating procedures. The operating procedures manual shall be maintained in an area allowing easy access to the boiler's operator and made available for Division review and inspection upon request.

- Good Combustion Technique: Maintenance Knowledge – The boiler must be maintained in accordance with manufacturer's specifications by personnel with training specific to the boiler and operating procedures.

- Good Combustion Technique: Maintenance Practices – Maintenance of a written site specific procedures manual for best/optimum maintenance practices in accordance to the manufacturer's specifications for the boiler. Periodic evaluations, inspections, and overhauls as appropriate of the boiler must be conducted in accordance with manufacturer's specifications. The maintenance practices must be updated as applicable with any equipment or operating practice changes. The modification of these practice changes, scheduled periodic evaluation inspections and overhaul, as appropriate, and any deviations from the prescribed maintenance practices shall be well documented in maintenance logs. The maintenance practices manual(s) shall be maintained in an area allowing easy access to the boiler's operator and made available for Division review and inspection upon request.

- Good Combustion Technique: Stoichiometic (fuel/air) Ratio – Yellow Pine must continuously monitor and adjust, as applicable, the fuel/air combustion ratio of the fluidized bed boiler per the manufacturer's specifications. Yellow Pine must, at a minimum, install a stack gas oxygen analyzer to continuously monitor excess air and adjust the boiler fuel-to-air ratio for optimum efficiency. In addition, a carbon monoxide trim loop, used in conjunction with the oxygen analyzer is required to assure that incomplete combustion cannot occur due to a deficient air supply. Yellow Pine will be required to operating a CO CEMs, with no exception, at the stack of the fluidized bed boiler, which will be discussed further below. Yellow Pine must submit a request for the Division's review and approval to install continuous fuel/air ratio monitor(s) different than the ones described here. The request must be submitted 30 days prior to proposed installation of the proposed monitor(s).

- Good Combustion Technique: Fuel Quality Analysis – Yellow Pine will be required to monitor the fuel quality of each of the fuels combusted in the fluidized boiler. Yellow Pine must obtain fuel quality certification from fuel oil, TDF, biomass, and propane suppliers to ensure that the fuel is of an acceptable standard to reduce emissions. These certifications should certify sulfur content, ash content, heating value, and moisture content, as applicable. If such certification cannot be obtained, Yellow Pine must conduct initial and periodic fuel sampling and analysis of the uncertified fuel. Such periodic fuel sampling shall be conducted as fired or weekly at a minimum. Such sampling shall include, but is not limited to moisture analysis, ash content, heating value, fuel ash content, and fuel sulfur content. Yellow Pine must develop and maintain fuel-handling practices as specified by the boiler manufacturer to ensure optimum quality necessary to ensure complete combustion, and make them available for review at the Division's request.

[7] *Good Combustion Practices* http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf, accessed March 5, 2008

- Good Combustion Technique: Fuel Sizing – Yellow Pine must develop fuel sizing specifications for applicable fuels (i.e. TDF and biomass) in accordance with manufacturer's specifications to ensure proper combustion efficiency of the fluidized boiler. Yellow Pine shall conduct periodic checks of the fuel sizing in accordance with the boiler manufacturer, or weekly at a minimum. Yellow Pine shall maintain logs of these checks and make them available for review at the Division's request.

- Good Combustion Technique: Combustion Air Distribution – Yellow Pine must monitor and adjust, when applicable, the air distribution system in accordance with the boiler manufacturer's specifications. Yellow Pine shall maintain logs of such combustion air distribution monitoring and adjusting, and make them available for review at the Division's request.

- Good Combustion Technique: Fuel Dispersion – Yellow Pine must monitor and adjust, when applicable, the fuel dispersion in accordance with the boiler manufacturer's specifications. Yellow Pine shall maintain logs of such fuel dispersion monitoring and adjusting, and make them available for review at the Division's request.

Conclusion – NOx Control

The BACT selection for the fluidized bed boiler is summarized below in Table 4-2:

**Table 4-2: BACT Summary for the Fluidized Bed Boiler**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| NOx | SNCR, Limestone/Sand Fluidized Bed, Combustion Controls, and Low NOx Burners | 0.10 lbs/$10^6$Btu | 30 day rolling average | CEMS |

Fluidized Bed Boiler – Particulate matter less than 10 micrometers in diameter ($PM_{10}$) Emissions

Emissions of PM, $PM_{10}$, and $PM_{2.5}$ result from inert solids contained in the fuel, unburned fuel hydrocarbons which agglomerate to form particles. All of the particulate matter emitted from the proposed boilers is expected to be less than 10 micrometers in diameter. Emissions of $PM_{10}$ will be used as a surrogate for $PM_{2.5}$.

Applicant's Proposal

*Step 1: Identify all control technologies*

In Application 17700, Yellow Pine evaluated pre and post combustion control technologies for the FB. The control technologies evaluated, verbatim as described in Application 17700, are as follows:

- Fuel Selection – In some instances, particulate emissions can be reduced by substitution of one fuel with another fuel that has lower ash content. Combustion of a lower ash-containing fuel will result in less fly ash generation, hence, less PM-10 emissions. This determination must be made on a case-by-case basis with consideration of the economic and logistical factors associated with the delivery of a specific type of fuel. Furthermore, it must be considered that the substitution of a fuel that produces less PM-10 emissions may cause an increase in other types of emissions, or increase auxiliary power consumption and/or reagent consumption (limestone, ammonia. etc.).

- Coal Cleaning – Coal cleaning will be discussed in detail in Section 5.3.3. In general, combustion of coal with less ash content will result in less fly ash generation and therefore, less PM-10 emissions.

- Electrostatic Precipitators (ESPs) – ESPs are rarely used on FB boilers using limestone injection in a dry scrubber for $SO_2$ control because the use of a FGD-baghouse combination significantly increases the achievable $SO_2$ control while achieving comparable PM control. As the flue gas passes through the filter cake, additional $SO_2$ is removed by unreacted limestone and calcium oxide in the filter cake. Additionally, due to the high resistivity of the PM-10, which is predominately calcium oxide and calcium sulfate, a very large ESP plate area would be required to match the collection efficiency of a baghouse making the use of an ESP more costly than a baghouse. Use of an ESP before or after a baghouse would have no measurable benefit and would actually reduce the effective baghouse performance if placed upstream due to the very high particulate removal capability of the baghouse. However, if a FGD system were not included in the design, then an ESP may become applicable.

- Wet Electrostatic Precipitator (WESP) – A WESP operates in the same three-step process as a dry ESP: charging, collection, and removal. Unlike a dry ESP, the removal of particles from the collection electrodes is accomplished by washing of the collection surface using liquid, rather than mechanical rapping the collector plates. WESPs are more widely used in applications where the gas stream has a high moisture content, is below the dew point, or includes sticky particulate.

- Wet Scrubbers and Mechanical Collectors –Wet scrubbers are not used for PM-10 control on fluidized bed boilers because of their lower overall collection efficiency, higher capital and operating costs, and the significant waste disposal and wastewater treatment issues that wet scrubbing entails. Wet scrubbers cannot be used in series with fabric filter baghouses to improve on PM control efficiency. If a wet scrubber is used upstream of the baghouse, the saturation of the flue gas with water will result in plugging of the fabric filter due to the reaction of condensed moisture with the highly alkaline particulate matter. There is no benefit to putting a wet scrubber downstream of the baghouse since wet scrubbers have higher emission rates of PM than baghouse due to entrained water droplets that evaporate to particulates.

  Mechanical collectors, such as cyclones, are used on FB boilers primarily for process reasons and secondary PM-10 control reasons. Cyclones permit un-combusted fuel to re-circulate back to the boiler, which is applicable when two dissimilar fuels are mixed is sizable proportions. For example, if biomass and coal were used 50/50, then given a single air velocity through the boiler, one would expect the less dense biomass to re-circulate, while the coal remained in the bed. In this case, biomass is 95% to 100% of the fuel mix by weight, so the air velocity would be tuned to combust biomass in the bed and a cyclone recirculation is not necessary. The solids disengagement section of the boiler is to separate the light fly ash material that exits the furnace and create the "bubbling bed" of uncombusted fuel. This bubbling process significantly improves overall combustion efficiency and uses limestone to efficiently capture acid gases such as $SO_2$. Secondly, the solids disengagement section reduces the particulate loading to the fabric filter baghouse reducing the frequency that the bags need to be replaced.

- Fabric Filter Baghouses –Baghouses have a number of inherent advantages when used for control of fly ash from FB boilers using limestone injection for acid gas control. These advantages include:

  - High PM-10 collection efficiencies as compared to other technologies,

  - PM-10 collection capability is not sensitive to typical fuel sulfur and limestone injection variabilities,

- Additional control of $SO_2$ and other acid gases due to the filtration of the flue gas through the alkaline filter cake, and
- High trace metal control efficiencies.

In addition to very high levels of particulate matter and fine particulate matter control, the baghouse system also increases the performance of $SO_2$ control systems. The baghouse creates a filter cake on the bag as the flue gas passes through the filter cake additional $SO_2$ is removed by the filter cake. The filter cake will include unreacted alkaline materials. Depending on the operating conditions of the baghouse, the fabric filter may remove 15 – 30% of the total $SO_2$ removed. The same mechanism for reducing $SO_2$ emissions in the baghouse also helps reduce inorganic acid gas emissions. The baghouses are also more efficient at removing fine particulate matter and trace metals than other particulate matter control systems, including ESPs. The primary disadvantage of baghouses relative to ESPs is the higher pressure drop across the baghouse resulting in increased fan power requirements for the system.

- Electro-Catalytic Oxidation (ECO) – The discussion presented in Section 5.3.1 for ECO is applicable to PM-10 emissions.

*Step 2: Eliminate technically infeasible options*

Yellow Pine determined that the following control options are technically infeasible as discussed verbatim as described in Application 17700 below:

- The PM-10 removal efficiency of wet scrubbers, mechanical collectors, and ESPs would be less than the removal efficiency of fabric filtration for FB boilers using limestone injection for $SO_2$ control. Additionally, these other control technologies offer no measurable benefit in increased particulate matter control if placed upstream or downstream of a properly sized baghouse.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

Application 17700's ranking of remaining control technologies by control effectiveness is nonexistent.

*Step 4: Evaluating the Most Effective Controls and Documentation*

Application 17700's evaluation of the most effective controls is nonexistent.

*Step 5: Selection of BACT*

According to Application 17700, the proposed BACT for the FB boiler(s) is fabric filter baghouses capable of achieving 99 percent removal and a $PM_{10}$ emissions of 0.033 lb/MMBtu.

EPD Review – Particulate matter less than 10 micrometers in diameter ($PM_{10}$) Emissions Control

The Division has determined that Yellow Pine's proposal to use fabric filter baghouses to minimize the emissions of $PM_{10}$ does not constitute BACT.

*Step 1: Identify all control technologies*

The Division agrees that the proposed control technologies are valid and applicable.

*Step 2: Eliminate technically infeasible options*

Yellow Pine eliminated fuel selection, ESP, and WESP as technically infeasible. The Division does not agree with this assessment for reasons discussed above concerning fuel selection as a potential $NO_x$ BACT selection.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

The Division has ranked the following technically feasible control technologies:

**Table 4-3: Ranking of Control Technology**

| Control Technology Ranking | Control Technology | Control Efficiency |
|---|---|---|
| 1 | Baghouse | 95% to 99.9% |
| 2 | ESP | 99% |
| 3 | WESP | 99% |
| 4 | Wet Scrubber | 95% |
| 5 | Mechanical Separators | 95% |
| 6 | Fuel Selection and Combustion Controls | Baseline |

*Step 4: Evaluating the Most Effective Controls and Documentation*

Since the submittal of Application 17700, Yellow Pine has removed the potential use of coal and petroleum coke as potential supplemental fuels. Yellow Pine may fire on a trial basis 95 percent metal free TDF in the bubbling fluidized bed boiler at 15% on a million Btu heat input basis.

The moisture content of the biomass also affects the amount of $PM_{10}$ emitted due to vapor resulting from the release of water. Test data indicates a TDF ash content of approximately seven percent.[8] Size of TDF (whole tires, chunk, shredded, or crumb rubber) and type (wire-included or de-wired) influences the rate and type of air emissions.[9] TDF combustion could result in metals emissions (i.e. particulates) due the presence of wire in the scrap tire and zinc, which is very prevalent in the tire manufacturing process. Particulate emissions may also increase as a result of the type of combustion feed rate (i.e. batch feed or steady state). Therefore, TDF's wire and metal content must be reduced to reduce the potential of $PM_{10}$ emitted.

*Step 5: Selection of BACT*

The Division proposes the installation of the most efficient post combustion technology. The Division has determined that fabric filter baghouse, good combustion controls as described for $NO_x$ BACT above, and limestone/sand fluidized bed are BACT. In addition, the Division will require that TDF must have resulted from the processing of de-wired tires. Yellow Pine must obtain certification from the TDF vendor that it is 95 percent metal free, as proposed in Application 17700.

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[8] *Air Emissions from Scrap Tire Combustion* EPA Office of Air Quality Planning and Standards and US-Mexico Border Information Center of Air Pollution EPA600/R97-115, page 33, October 1997.

[9] *Air Emissions from Scrap Tire Combustion* EPA Office of Air Quality Planning and Standards and US-Mexico Border Information Center of Air Pollution EPA600/R97-115, page 40, October 1997.

The Division reviewed the National Associate of Clean Air Agencies' (NACAA's) Reducing Hazardous Air Pollutants from Industrial Boilers: Model Permit Guidance (June 2008), which was developed based on existing particulate matter emissions data relating to industrial, commercial and institutional boilers and process heaters (ICI Boilers). The document indicates that after review of data of 109 wood-fired boilers it determined that particulate matter emissions for an existing boiler range from 0.010 to 0.020 lbs/$10^6$Btu. Per Permit Application 17700, similar projects have filterable particulate matter emission limits as low as 0.010 lbs/$10^6$Btu. Therefore, the Division will impose a filterable $PM_{10}$ limit of 0.010 lbs/$10^6$Btu (which is evaluated to equate to 15.3 lbs/hr and 67 tons/year) as BACT at the stack outlet. Total $PM_{10}$ limit is 0.018 lbs/$10^6$Btu (which is evaluated to equate to 27.5 lbs/hr and 121 tons/year) as BACT at the stack outlet. These limits are applicable at all times, including startup and shutdown.

The baghouse must be installed in stack for the fluidized bed boiler, and must be operated at all times the fluidized bed boiler is in operation, regardless of the fuel type being combusted.

Conclusion – Particulate matter less than 10 micrometers in diameter ($PM_{10}$) Emissions Control

The BACT selection for the fluidized bed boiler is summarized below in Table 4-4:

**Table 4-4: BACT Summary for the Fluidized Bed Boilers**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| $PM_{10}$ (filterable) | Fabric Filter Baghouse, Good Combustion Controls, and Limestone Fluidized Bed | 0.010 lbs/$10^6$Btu | 3-run test average | Performance Testing |
| $PM_{10}$ (total) | Fabric Filter Baghouse, Good Combustion Controls, and Limestone Fluidized Bed | 0.018 lbs/$10^6$Btu | 3-run test average | Performance Testing |
| $PM_{10}$ | Wire Content of Tires used to make TDF | 0% | None | Vendor Certification or Fuel Analysis |
| $PM_{10}$ | Metal Content of TDF | <5% | None | Vendor Certification or Fuel Analysis |

Fluidized Bed Boiler – Sulfur Dioxide ($SO_2$) Emissions

Sulfur dioxide ($SO_2$) is emitted as a result of the oxidation of the sulfur in the fuel. Sulfuric acid mist ($H_2SO_4$) is formed when gas phase $SO_3$ reacts with vapor phase water ($H_2O$) to form vapor phase $H_2SO_4$. Sulfuric acid mist emissions are not expected to be above PSD significance because Yellow Pine no longer proposes to use bituminous coal or petroleum coke as supplemental fuels.

Applicant's Proposal

*Step 1: Identify all control technologies*

In Application 17700, Yellow Pine evaluated pre and post combustion control technologies for the FB. The control technologies evaluated, verbatim as described in Application 17700, are as follows:

- Fuel Selection – The combustion of sulfur contained in the fuel is the primary source of $SO_2$ emissions from the combustion of biomass, coal, pet coke, and TDF. Firing fuel with lower sulfur content is a common method to lower $SO_2$ emissions, especially for boilers not equipped with flue gas desulfurization systems. The boiler will be primarily fired on biomass which has an extremely low sulfur content of approximately 0.02 percent. However, the use of flue gas desulfurization systems affords boiler operators flexibility in fuel purchasing with respect to the secondary fuels, which in this case will be coal, pet coke, and TDF.

- Coal Cleaning – Coal normally contains significant quantities of inorganic elements such as iron, aluminum, silica, and sulfur. These elements occur primarily in ash-forming mineral deposits embedded within the coal but are also present to a lesser degree within the organic coal structure. Coal cleaning is a process that removes this mineral ash from the coal after it is removed from the ground. The relative amounts of contaminants, the manner in which they are included in the coal assemblage, and the degree to which they can be removed vary widely with different coals. The removal of this non-combustible material improves the heating value of the coal. The cleaning also removes some portion of sulfur, mostly pyretic sulfur, which may account for 10% to 80% of the total fuel sulfur content. The application and extent of coal cleaning depends on the particular mine and mining technique. Underground mines often clean coal prior to shipment, whereas surface mines tend to employ coal cleaning based upon the effectiveness of the overburden removal and thickness of the coal seam.

- FB Boilers, Limestone Injection for $SO_2$ Control – The development of FB boiler technology has been driven largely by the need to reduce $SO_2$ and $NO_X$ emissions from the combustion of high sulfur fuel such as coal. The major advantages to the FB boiler technology are the ability of controlling emissions of $SO_2$ to very low levels "in-situ" without post combustion air pollution control systems, and the ability to process a wide range of solid fuels without modifications. The FB boiler combusts solid fuels in a fluid bed mixture of fuel, char, ash, and other materials (limestone or sand) used to provide the desired bed characteristics. Combustion air forced in at the bottom of the furnace keeps the bed mixture in a constant upward moving fluid flow. Combustion takes place within the furnace at low combustion temperatures ranging from 1,500 to 1,600°F. The low combustion temperature allows for good absorption of $SO_2$ with alkaline materials (calcium, sodium, etc.) contained in the fuel ash or added with the bed material (i.e., limestone). Additionally, the low combustion temperatures reduce ash fusion problems associated with the combustion of solid fuels in conventional boilers.

  There are generally two types of fluidized bed boilers: atmospheric (AFB) and pressurized (PFG). AFB boilers have been used commercially for many years with the circulating bed type being the predominate process type. PFB boilers have very limited commercial scale experience and will not be discussed further.

  There are two major AFB boiler types: the "bubbling" bed and the "circulating" bed boiler. The circulating fluidized bed boilers have high fluidized air velocities ranging from 10 to 20 ft/sec, lack a distinct transition from the dense bed at the bottom of the furnace to the dilute zone above, and have a very high flow rate of re-circulated solids. The high fluidizing air velocity results in a turbulent fluidized bed and a high rate of entrained solids carried out of the boiler. These solids are separated from the combustion gases in a cyclone solids disengagement section and returned to the furnace to improve combustion efficiency and limestone utilization. Circulating FB boilers are applicable to biomass although given the high proportion of biomass by weight fraction, with its low sulfur content, the recirculation feature is not essential.

In the bubbling fluidized bed boiler, the bed of materials including the limestone/sand, fuel, and ash is suspended by the combustion air blowing upward through an air distributor plate at relatively low velocities of 1 – 5 ft/sec. The bed itself is typically about four feet deep in its fluidized condition, and is characterized by a sharp density profile at the top of the bed. The sharp drop-off in density indicates the end of the bubbling fluidized bed. In a bubbling bed, the bed level is easy to see, and there is a distinct transition between the bed and the space above. Because most or all of the fuel input is biomass, a bubbling type FB boiler is applicable.

When the boiler is fired on biomass and either coal, pet coke or TDF, $SO_2$ emissions are controlled directly in the boiler by injecting limestone with fuel directly into the fluidized bed. When the boiler is fired only on biomass, sand will be used instead of limestone because there will be no effective reduction in already low $SO_2$ emissions that will result from the combustion of biomass. Within the furnace, limestone is first "calcined" to calcium oxide. Calcium oxide then reacts with $SO_2$ in the fluidized bed to form calcium sulfate. The chemistry of the $SO_2$ reaction includes the following:

1. Calcination: $CaCO_3$ (s) + 766Btu/(lb of $CaCO_3$) ==> CaO (s) + $CO_2$ (g)
2. Adsorption: $SO_2$ (g) + 1/2$O_2$ (g) + CaO (s) ==> $CaSO_4$ (s) + 6733 Btu/(lb of S)
3. Overall: $CaCO_3$ (s) + $SO_2$ (g) + 1/2$O_2$ ==> $CaSO_4$ (s) + $CO_2$ (g) + 5967 Btu/(lb of S)

Calcium sulfate or gypsum is chemically stable in the fluidized bed at normal operating temperatures and is rejected from the system in the furnace bottom ash draw and in fabric filter baghouse ash draw. The ash draw contains primarily fuel ash, gypsum, unreacted calcium oxide, and char and is disposed of as non-hazardous solid waste.

The primary factor affecting fluidized bed boiler performance is the calcium-to-sulfur molar feed (Ca/S) ratio, which is a function of the fuel sulfur content and the percent $SO_2$ removal desired. As the calcium content of the bed increases, greater amounts of $SO_2$ are removed. The importance of the Ca/S ratio extends beyond $SO_2$ removal; it also affects the mass rate of the bed material flowing through the boiler which affects the size of the boiler, and the operating costs for limestone, furnace wall erosion, and auxiliary power requirements. As the Ca/S ratio increases, the mass of solids flowing through the unit increases.

- Dry Flue Gas Desulfurization – The use of a dry flue gas desulfurization system such as lime spray drying followed by a baghouse has the potential to reduce $SO_2$ emissions by 75 to 90 percent. Using 90 percent control efficiency during the 85 percent biomass and 15 percent coal firing scenario, results in an emission rate of 0.10 lb/MMBtu which represents an overall $SO_2$ control efficiency of 93 percent. The lowest permitted $SO_2$ emission rate for a coal-fired FB boiler in the RBLC using lime spray scrubbing technology is 0.22 lb/MMBtu. The lowest permitted $SO_2$ emission rate for a biomass-fired boiler using lime spray scrubbing technology in the RBLC database is 0.10 lb/MMBtu.

- Circulating Dry Scrubber (CDS) – The CDS is a once-through dry technology. In a CDS, flue gas, ash, and lime sorbent form a fluidized bed in an absorber vessel. The flue gas is humidified in the vessel to aid the adsorption reactions between lime and $SO_2$. The by-products leave the absorber in a dry form with the flue gas and are subsequently captured in a downstream particulate collection device. CDS have only been domestically applied to two coal-fired boilers. These boilers are 60 and 80 MW units. Therefore, this technology is considered technically infeasible and will not be considered further in this application.

- Duct Sorbent Injection (DSI) – DSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb $SO_2$. In the DSI technology, the reagent is injected into the ductwork between the air heater and particulate control device. The DSI technology is still undergoing significant research and development aimed at improving performance and increasing the scale of applications. Therefore, this technology is considered technically infeasible and will not be considered further in this application.

- Activated Carbon Bed – The only potentially applicable regenerable dry technology is based on the use of activated carbon. In the FGD process, the activated carbon is present in a moving bed through which the flue gas flows. The activated carbon serves as the sorbent for removal of the $SO_2$. As the activated carbon becomes saturated with $SO_2$, it is regenerated and the $SO_2$ is released as a stream of gaseous $SO_2$. There is no record of commercial application of this technology. Therefore, this technology is considered technically infeasible and will not be considered further in this application.

- Wet Scrubber – The wet scrubber is a once-through wet technology. In a wet scrubber system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The $SO_2$ is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a wet form upon leaving the system and must be dewatered prior to transport/disposal.

  The wet scrubber can be further classified on the basis of the reagents used and by-products generated. The typical reagents are lime and limestone. Additives, such as magnesium, may be added to the lime or limestone to increase the reactivity of the reagent. Seawater has also been used as a reagent since it has a high concentration of dissolved limestone. The reaction by-products are calcium sulfite and calcium sulfate. The calcium sulfite to calcium sulfate reaction is a result of oxidation, which can be inhibited or forced depending on the desired by-product. The most common wet scrubber application utilizes limestone as the reagent and forced oxidation of the reaction by-products to form calcium sulfate.

  Wet scrubbers have been applied on coal-fired boilers and are commercially available from a number of suppliers. Wet scrubbers that use limestone, lime, magnesium-enhanced lime, forced oxidation, and inhibited oxidation are all considered technically feasible control technologies with control efficiency of 90 percent to greater than 95 percent.

- Regenerable Wet Scrubber – The regenerable wet scrubber is a technology that uses sodium sulfite, magnesium oxide, sodium carbonate, amine, or ammonia as the sorbent for removal of $SO_2$ from the flue gas. The spent sorbent is regenerated to produce concentrated streams of $SO_2$ or other sulfur compounds which may be further processed to produce other products. These FGD technologies may require additional flue gas treatment prior to the $SO_2$ absorption process in order to remove other flue gas constituents such as hydrogen chloride and hydrogen fluoride that may affect the sorbent an/or final by-product.

  The sodium sulfite and ammonia based technologies have been commercially applied and are available from a number of suppliers. These technologies are considered to technically feasible with control efficiency of 90 percent to greater than 95 percent. The other technologies either have limited or no record of commercial application; are considered technically infeasible, and will not be considered further in this application.

- Electro-Catalytic Oxidation and Pahlman Process – Two of the add-on controls described in Section 5.3.1 also controls $SO_2$. These add-on controls are Electro-Catalytic Oxidation and Pahlman Process.

*Step 2: Eliminate technically infeasible options*

Yellow Pine determined that none of the control options described in Application 17700 were technically infeasible.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

Application 17700's ranking of remaining control technologies by control effectiveness is nonexistent.

*Step 4: Evaluating the Most Effective Controls and Documentation*

Application 17700's evaluation of the most effective controls is nonexistent.

*Step 5: Selection of BACT*

According to Application 17700, the proposed BACT for the FB boiler(s) is a dry scrubber system. Yellow Pine Energy requested the following $SO_2$ permit limits:

- 3 hour – 0.19 lb/$10^6$Btu
- 24 hour – 0.13 lb/$10^6$Btu
- 30 day – 0.10 lb/$10^6$Btu

EPD Review – Sulfur Dioxide ($SO_2$) and Sulfuric Acid Mist ($H_2SO_4$) Emissions Control

The Division has determined that Yellow Pine's proposal to use a dry scubber to minimize the emissions of $SO_2$ does not constitute BACT.

*Step 1: Identify all control technologies*

The Division has reviewed the following additional control technologies:

- Lime Fluidized Bed – This control technology would utilize lime in the fluidized bed of the boilers rather than limestone to control $SO_2$ emissions. The operation of the bed would be the same as if operating the bed using limestone.

*Step 2: Eliminate technically infeasible options*

The Division has reviewed the following additional control technologies for technical feasibility:

- Lime Fluidized Bed – This control technology is technically feasible.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

**Table 4-5: Ranking of Control Technology**

| Control Technology Ranking | Control Technology | Control Efficiency |
|---|---|---|
| 1 | Wet Scrubber | 90% to 95% |
| 2 | Dry FGD | 75% to 90% |
| 3 | Lime Injection | 90% |
| 4 | Limestone Injection | 90% |

| Control Technology Ranking | Control Technology | Control Efficiency |
|---|---|---|
| 5 | Fuel Selection, Limestone Fluidized Bed and Combustion Controls | Baseline |

*Step 4: Evaluating the Most Effective Controls and Documentation*

The Division briefly reviewed potential economic and environmental impacts associated with lime fluidized bed technology. The Division contacted a major boiler manufacturer to discuss the potential of using lime versus limestone in fluidized bed boilers similar to what is being proposed for Yellow Pine. The representative indicated that there is an added expense of using lime versus limestone, as it is not readily available in nature. The lime would have to be manufactured. If manufactured onsite, there would be an additional requirement of energy as it takes heating limestone to at least 1500 degrees Fahrenheit ($^{o}$F) to make lime. If lime were to be obtained from offsite, it would require specialized additional storage as well as resulting in a must higher capital cost than that of limestone. In addition, handling of lime is more involved as it is a hazardous substance. As with limestone, the size distribution will have to be monitored. However, in the case of lime, the relatively soft lime's size could be easily altered, even if initially properly sized. The breakdown of the lime can result in the build up of additional sulfates in the fluidized bed that will result in longer circulation of bed material sulfates.[10] Therefore, the Division has determined that the potential economic and environmental impacts render lime fluidized bed control technology as infeasible. As a result, the Division has determined that this technology has economic and environmental impacts, and it will no longer be considered.

TDF sulfur content testing indicates a sulfur content of approximately 1.2 % [11]. The reduction of sulfur content of these fuels is relatively nonexistent.

The sulfur content of biomass and propane is relatively low and are not expected to contribute much to $SO_2$ emissions. Yellow Pine proposed in its application and subsequent submittals that it believes that the sulfur content of biomass is 0.02%. The Division believes this estimate is high to a certain extent, and that the sulfur content of biomass is more accurately 0.01% as indicated in the Division's November 12, 2008 letter to Yellow Pine.

Yellow Pine proposes to use low sulfur fuel oil with a sulfur content of 0.05 percent. By the year 2010, the emergency generator and water fuel pump engine are required to use diesel fuel with the fuel sulfur content of 15 parts per million (ppm). Therefore, to reduce facility-wide emissions, the Division has determined that Yellow Pine can only burn fuel oil in the fluidized boiler with a sulfur content less than or equal to 15 parts per million (ppm) by the year 2010.

*Step 5: Selection of BACT*

The Division proposes the following $SO_2$ emission limit is 0.01 lbs/$10^6$Btu (which is evaluated to equate to 15.3 lbs/hr and 67 tons/year) as BACT at the stack outlet. To ensure compliance with the limits, Yellow Pine will also be required to install a $SO_2$ CEMs at the stack outlet. The Division has determined that a dry flue gas desulfurization scrubber system, good combustion controls as described for $NO_x$ BACT above, $SO_2$ CEMs, and limestone/sand fluidized bed are BACT. As previously discussed, the same emissions limits shall apply at all times including startup and shutdown no matter what the fuel burned.

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[10] March 24, 2008 phone conversation with Mike Maryamchick, Circulating Fluidized Bed Boilers technical contact of The Babcock & Wilcox Company.

[11] *Air Emissions from Scrap Tire Combustion* EPA Office of Air Quality Planning and Standards and US-Mexico Border Information Center of Air Pollution EPA600/R97-115, page 37, October 1997.

The dry scrubber system and CEMs must be installed in stack for the fluidized bed boiler, and must be operated at all times the fluidized bed boiler is in operation, regardless of the fuel type being combusted.

Conclusion – Sulfur Dioxide ($SO_2$) Control
The BACT selection for the fluidized bed boiler is summarized below in Table 4-6:

**Table 4-6: BACT Summary for the Fluidized Bed Boiler**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| $SO_2$ | Dry Scrubber System, Combustion Controls, and Limestone/Sand Fluidized Bed | 0.01 lbs/$10^6$ Btu | 30 day rolling average | CEMS |
| $SO_2$ | Low Sulfur Fuel Oil | Sulfur content of 0.05 % and a sulfur fuel oil content of 15 ppm by 2010 | None | Fuel Analysis or Vender Certification |

Fluidized Bed Boiler – Carbon Monoxide (CO) Emissions

Carbon Monoxide emissions will be emitted from the boiler(s) as a result of incomplete fuel combustion. Incomplete combustion also leads to emissions of PM and HAPs.

Care must be taken when incorporating design changes to reduce both $NO_x$ and CO emissions. CO emission combustion modifications can possibly increase $NO_x$ emissions and vice versa. A balance between these air pollutants must be achieved in order for combustion modification to be useful.

Applicant's Proposal

*Step 1: Identify all control technologies*

In Application 17700, Yellow Pine evaluated pre and post combustion control technologies for the FB. The control technologies evaluated, verbatim as described in Application 17700, are as follows:

- Combustion Controls – Optimization of the design, operation, and maintenance of high combustion temperatures for control of CO emissions will lead to an increase of $NO_X$ emissions. Consequently, typical practice is to design the furnace/combustion system (specifically, the air/fuel mixture and furnace temperature) such that CO emissions are reduced as much as possible without causing $NO_X$ levels to significantly increase. Proper operation and maintenance of the furnace/combustion system will help to minimize the formation and emission of CO by ensuring that the furnace/combustion system operates as designed. This includes maintaining the air/fuel ratio at the specified design point, having proper air and fuel conditions at the burner, and maintaining the fans and dampers in the proper working conditions.

- Flares – Flares are commonly used in the control of waste streams from refineries and other chemical processes with low heating value, organic, and gaseous. In the case of a biomass, coal, pet coke, TDF-fired boilers, there are insufficient organics in the exhaust to support combustion without a significant addition of supplementary fuel (natural gas). As a result, the secondary impact of the flare would be the creation of additional emissions, including $NO_X$.

- Afterburning – Afterburners convert CO into $CO_2$ by utilizing simple gas burners to bring the temperature of the exhaust stream up to 1400°F to promote complete combustion. Afterburners, like flares, would require significant amounts of natural gas and would result in the formation of additional pollutants such as $NO_X$.

- Catalytic Oxidation – A catalytic oxidizer converts the CO in the combustion gases to $CO_2$ at temperatures ranging from 500°F to 700°F in the presence of a catalyst. A major operating drawback of the catalytic oxidizer is that fine particulate suspended in the exhaust gases can foul and poison the catalyst. The problem of catalyst poisoning can be minimized if the catalytic oxidizer is placed downstream of a particulate matter control device. However, this would require reheating the exhaust gases to the required operating temperature for the catalytic process. Another significant disadvantage of the catalytic oxidizer is that $SO_2$ in the flue gas stream may be oxidized to form $SO_3$. The resulting $SO_3$ may react with moisture in the flue gas to form sulfuric acid.

- External Thermal Oxidation (ETO) – ETO promotes thermal oxidation of the CO in the flue gas stream in a location external to the boiler. ETO requires heat (1400°F to 1600°F) and oxygen to convert CO in the flue gas to $CO_2$. There are two general types of ETO that are used for control of CO emissions: regenerative thermal oxidation and recuperative thermal oxidation. The primary difference between regenerative thermal oxidation and recuperative ETO is that regenerative ETO utilized a combustion chamber and ceramic heat exchange canisters that are an integral unit, while recuperative ETO utilizes a separate counterflow heat exchanger to preheat incoming air prior to entering the combustion chamber.

*Step 2: Eliminate technically infeasible options*

Yellow Pine determined that the following control options are technically infeasible as discussed verbatim as described in Application 17700 below:

- Flares – Flares are commonly used in the control of waste streams from refineries and other chemical processes with lower heating value, organic, and gaseous. Flares have not been demonstrated for control of CO from fluidized bed boilers and limitations on the scalability of this technology preclude its commercial availability. In addition, flares are not listed as a control for CO emissions from fluidized bed boilers in the RBLC database. Therefore, flares are considered technically infeasible and will not be considered further in this application.

- Afterburning – Afterburners have not been demonstrated for control of CO emissions from fluidized bed boilers. There would be significant secondary impacts and practical considerations to the application of this technology for the reduction of CO emissions from fluidized bed boilers including additional production of $NO_X$ and substantial natural gas usage for a relative small decrease of CO emissions. In addition, afterburners are not listed as a control for CO emissions from fluidized bed boilers in the RBLC database. Therefore, afterburners are considered technically infeasible and will not be considered further in this application.

- Catalytic Oxidation – Catalytic oxidation is generally utilized for CO emission reductions on non-combustion CO sources. Catalytic oxidation has not been demonstrated and is not commercially available for use on fluidized bed boilers. In addition, catalytic oxidation is not listed as a control for CO emissions from fluidized bed boilers in the RBLC database. Therefore, catalytic oxidation is considered technically infeasible and will not be considered further in this application.

- External Thermal Oxidation (ETO) – ETO is generally utilized for CO emissions reductions on non-combustion sources. Regenerative ETO and recuperative ETO have not been demonstrated and are not commercially available for use on fluidized bed boilers. There are significant secondary impacts and other issues that would preclude the use of this technology as a CO emissions reduction technology for fluidized bed boilers. These include additional production of $NO_X$, substantial natural gas usage for a relatively small decrease of CO emissions and increased maintenance concerns. In addition, ETO is not listed as a control for CO emissions from fluidized bed boilers in the RBLC database. Therefore, ETO is considered technically infeasible and will not be considered further in this application.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

Application 17700's ranking of remaining control technologies by control effectiveness is nonexistent.

*Step 4: Evaluating the Most Effective Controls and Documentation*

Application 17700's evaluation of the most effective controls is nonexistent.

*Step 5: Selection of BACT*

According to Application 17700, the proposed BACT for the FB boiler(s) for CO emissions control is the application of combustion controls with an emission limit of 0.30 lb/MMBtu.

<u>EPD Review – Carbon Monoxide (CO) Control</u>
The Division has determined that Yellow Pine's proposal to use a combustion controls to minimize the emissions of CO does not constitute BACT.

*Step 1: Identify all control technologies*

The Division agrees that the proposed control technologies are valid and applicable.

*Step 2: Eliminate technically infeasible options*

Application 17700 eliminates several of the proposed CO control technologies, in particular catalytic oxidation, because they have not been demonstrated on fluidized bed boilers. Eliminating a control technology because it has not been demonstrated for a specific combustion source is inaccurate. As discussed above in the review of $NO_x$ BACT, the Division requested that Yellow Pine adequately conduct top-down BACT analysis for all applicable pollutants and conduct cost analysis, as applicable.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

**Table 4-7: Ranking of Control Technology**

| Control Technology Ranking | Control Technology | Control Efficiency |
|---|---|---|
| 1 | Catalytic Oxidation | 90% |
| 2 | Fuel Selection, Limestone Fluidized Bed and Combustion Controls | Baseline |

*Step 4: Evaluating the Most Effective Controls and Documentation*

The moisture content of biomass affects the potential emissions of CO because of the potential of incomplete combustion. Therefore, the moisture content must be limited to reduce this potential.

*Step 5: Selection of BACT*

The Division requested that Yellow Pine look at the potential of catalytic oxidation in relationship to the potential of installing a RSCR for $NO_x$ control. The RSCR has been eliminated as potential $NO_x$ control. Although catalytic oxidation would provide the highest level of CO emissions reduction, the Division has considered that achieving the relatively conservative $NO_x$ BACT limit will have an effect on the amount that CO emissions can be controlled due to the inverse relationship of $NO_x$ and CO. The Division has determined that good combustion controls as described for $NO_x$ BACT above and limestone/sand fluidized bed are BACT.

The Division proposes the following CO emission limit is 0.149 lbs/$10^6$Btu (which is evaluated to equate to 228 lbs/hr and 998 tons/year) as BACT at the stack outlet. The same emissions limits shall apply at all times including startup and shutdown no matter what the fuel burned. To ensure compliance with the limits, Yellow Pine will also be required to install a CO CEMs at the stack outlet. The CEMs must be installed in stack for the fluidized bed boiler, and must be operated at all times the fluidized bed boiler is in operation, regardless of the fuel type being combusted.

Conclusion – Carbon Monoxide (CO) Control

The BACT selection for the fluidized boiler is summarized below in Table 4-8:

**Table 4-8: BACT Summary for the Fluidized Bed Boiler**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| CO | Good Combustion Controls and Limestone/Sand Fluidized Bed | 0.149 lbs/$10^6$ Btu | 30 day rolling average | CEMS |

Fluidized Bed Boiler – Volatile Organic Compounds (VOCs) Emissions

Volatile organic compounds (VOCs) are substances that can photochemically react in the atmosphere which are released during the combustion of fuel.

Applicant's Proposal

*Step 1: Identify all control technologies*

In Application 17700, Yellow Pine evaluated pre and post combustion control technologies for the FB. The control technologies evaluated, verbatim as described in Application 17700, are as follows:

- Combustion Controls – As described in Section 5.3.4 for control of CO emissions, combustion controls are also applicable for the control of VOC emissions.

- Flares, Afterburning, Catalytic oxidation, and External Thermal Oxidation – The add-on controls described in Section 5.3.4 for control of CO emissions are also applicable for control of VOC emissions. These add-on controls include flares, afterburning, catalytic oxidation, and external thermal oxidation.

*Step 2: Eliminate technically infeasible options*

Yellow Pine determined that the following control options are technically infeasible as discussed verbatim as described in Application 17700 below:

- Flares, Afterburning, Catalytic oxidation, and External Thermal Oxidation – Generally, technologies that are not commercially available, lack experience in comparable applications, or are not applicable were considered infeasible. The discussion presented in Section 5.3.4 with respect to CO emissions is applicable to VOC emissions and is not repeated here.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

Application 17700's ranking of remaining control technologies by control effectiveness is nonexistent.

*Step 4: Evaluating the Most Effective Controls and Documentation*

Application 17700's evaluation of the most effective controls is nonexistent.

*Step 5: Selection of BACT*

According to Application 17700, the proposed BACT for VOC emissions control is the application of combustion controls with an emission limit of 0.020 lb/$10^6$Btu during 100 percent biomass firing and 0.018 lb/$10^6$Btu when biomass is fired with up to 15 percent coal, pet coke, or TDF.

EPD Review – Volatile Organic Compounds (VOCs) Control
The Division has determined that Yellow Pine's proposal to use of combustion controls to minimize the emissions of VOCs does not constitute BACT.

*Step 1: Identify all control technologies*

The Division agrees that the proposed control technologies are valid and applicable.

*Step 2: Eliminate technically infeasible options*

Application 17700 eliminates several of the proposed VOC control technologies because they have not been demonstrated on fluidized bed boilers. Eliminating a control technology because it has not been demonstrated for a specific combustion source is inaccurate.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

**Table 4-9: Ranking of Control Technology**

| Control Technology Ranking | Control Technology | Control Efficiency |
|---|---|---|
| 1 | Catalytic Oxidation | 90% |
| 2 | Fuel Selection, Limestone Fluidized Bed and Combustion Controls | Baseline |

*Step 4: Evaluating the Most Effective Controls and Documentation*

The moisture content of biomass affects the potential emissions of VOC because of the potential of incomplete combustion. Therefore, the moisture content must be limited to reduce this potential.

*Step 5: Selection of BACT*

The Division has determined that good combustion controls as described for $NO_x$ BACT above and limestone/sand fluidized bed are BACT. The Division proposes the following VOC emission limit is 0.02 lbs/$10^6$Btu(which is evaluated to equate to 30.6 lbs/hr and 134 tons/year) as BACT at the stack outlet. The same emissions limit shall apply at all times including startup and shutdown no matter what the fuel burned. As previously discussed, Yellow Pine has yet to provide an adequate proposal for monitoring the amount and type of each fuel, therefore, the same emissions limit listed below shall apply no matter what the fuel burned.

Conclusion – Volatile Organic Compounds (VOCs) Control

The BACT selection for the fluidized bed boiler is summarized below in Table 4-10:

**Table 4-10: BACT Summary for the Fluidized Bed Boiler**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| VOC | Good Combustion Controls and Limestone/Sand Fluidized Bed | 0.02 lbs/$10^6$ Btu | 3 test run average | Performance Testing |

Fluidized Bed Boiler – Lead (Pb) Emissions

Emissions of Pb result from inert solids contained in the fuel, unburned fuel hydrocarbons which agglomerate to form particles. All of the lead emitted from the proposed boiler is expected to be particulate matter less than 10 micrometers in diameter.

Yellow Pine will no longer burn coal or pet coke as supplemental fuels. Therefore, lead emissions should not trigger significant modification threshold. Therefore, to assure lead remain below the PSD SL level, the Division proposes a PSD avoidance limit of 3.0 x 10-5 lbs/106 Btu (which is evaluated to equate to 0.05 lbs/hour and 0.2 tons per year).

Fluidized Bed Boiler – Fluorides (F), Hydrogen Sulfide ($H_2S$), and Total Reduced Sulfur (TRS) Emissions

Fluorides (F), Hydrogen Sulfide ($H_2S$), and Total Reduced Sulfur (TRS) are released to the air during the combustion of fuel. The Division requested that Yellow Pine evaluate emissions of these pollutants from its facility. In CH2M Hill's November 30, 2007 letter, Yellow provided emission estimates of these pollutants; however, no data was provided how these values were determined. The Division has determined that $SO_2$ controls will address potential F, TRS, and $H_2S$ emissions.

## Auxiliary Boiler – Background

The auxiliary boiler (Source Code AB) has a heat input capacity of 25 x $10^6$ Btu/hr, and will be limited to a total of 250 hours per calendar year. It was to be manufactured and installed in 2008. This boiler will be used to provide auxiliary steam for the fluidized boiler. According to Application 17700, aside from maintenance testing of the auxiliary boiler, it will only be used during facility startup activities. Primary emissions from the auxiliary boiler are nitrogen oxides, particulate matter, carbon monoxide, volatile organic compounds, and sulfur dioxide. Like the proposed fluidized bed boiler, the proposed auxiliary boiler will be equipped with low $NO_x$ burners.

Nitrogen oxides, particulate matter, carbon monoxide, volatile organic compounds, and sulfur dioxide emissions increases from the auxiliary boiler would have triggered PSD applicability. However, the Division has determined the operation hours limitation above constitutes BACT. The following table summarizes worst case (i.e. low sulfur fuel oil combustion) potential emissions of the discussed pollutants, based on the operation hours limit.

**Table 4-11: Summary of Potential Auxiliary Boiler Emissions Based on Operation Hour Limit**

| Pollutant | Emissions (lbs/hr) | Emissions (lbs/day)[1] | Emissions (lbs/year)[2] | Emissions (tons/year) |
|---|---|---|---|---|
| $NO_x$ | 3.57 | 85.7 | 893 | 0.45 |
| PM | 0.36 | 8.87 | 89.3 | 0.04 |
| $PM_{10}$ | 0.18 | 4.26 | 44.6 | 0.02 |
| $PM_{2.5}$ | 0.04 | 1.07 | 11.2 | 0.01 |
| CO | 0.89 | 21.4 | 223 | 0.11 |
| TOC[3] | 0.06 | 1.08 | 11.3 | 0.01 |
| $SO_2$ | 1.27 | 30.4 | 317 | 0.16 |

[1]Based on a 24-hour day
[2]Based on 250 hours per year
[3]TOC = Total Organic Compounds

Yellow Pine must comply with the requirements of 40 CFR Part 60, Subpart Dc. The ensure compliance with the operating hours limitation, Yellow Pine must install a non-resettable hour meter to record the operating hours of the boiler. Yellow Pine must also practice good combustion controls for the auxiliary boiler.

Yellow Pine must limit the fuel types to propane and low sulfur fuel oil, at a minimum for the auxiliary boiler. Yellow Pine proposes to use low sulfur fuel oil with a sulfur content of 0.05 percent. By the year 2010, the emergency generator and water fuel pump engine require the use of diesel fuel with the fuel sulfur content of 15 parts per million (ppm). Therefore, to reduce facility-wide emissions, Yellow Pine can only burn fuel oil in the auxiliary boiler with a sulfur content less than or equal to 15 parts per million (ppm) by 2010.

## Material Storage and Handling [Fuel Process Buildings 1 and 2 (FPB 1 and FPB 2), Tripper Deck Day Silos 1-5 (TDS 1-5), Fuel Storage Silo (SLO), and Fly Ash Silo (AS)] - Background

The equipment listed above are the non-fugitive material (e.g. biomass, limestone, sand, and ash) storage and handling systems. It was proposed to be manufactured and installed in 2008. Primary emissions from this equipment are $PM_{10}$.

Because only $PM_{10}$ emissions increases from this equipment have triggered PSD applicability, only $PM_{10}$ emissions were evaluated for Best Available Control Technology (BACT).

### Material Storage and Handling [Fuel Process Buildings 1 and 2 (FPB 1 and FPB 2), Tripper Deck Day Silos 1-5 (TDS 1-5), a Fuel Storage Silo (SLO), and Fly Ash Silo (AS)] – Particulate matter less than 10 micrometers in diameter ($PM_{10}$) Emissions

Applicant's Proposal

In Application 17700, Yellow Pine evaluated pre and post combustion control technologies for the material storage and handling equipment listed above. The control technologies evaluated, verbatim as described in Application 17700, are as follows:

*Step 1: Identify all control technologies*

- Transfer point enclosures, usually used in conjunction with other control technologies such as water sprays or fabric filters, are technically feasible for the control of PM/PM-10 emissions at material transfer points where structural and operational considerations do not preclude their use.

- Material storage building and silos are technically feasible for the control of PM/PM-10 emissions from material handling operations but only in applications where structural and operational considerations do not preclude their use.

*Step 2: Eliminate technically infeasible options*

Application 17700's elimination of technically infeasible options is nonexistent. Application 17700 indicates that fabric filters are technically feasible PM/PM-10 emissions control technology only when the source of emissions can be enclosed and funneled through a vent.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

Application 17700's ranking of remaining control technologies by control effectiveness is nonexistent.

*Step 4: Evaluating the Most Effective Controls and Documentation*

Application 17700's evaluation of the most effective controls and documentation is nonexistent.

*Step 5: Selection of BACT*

According to Application 17700, water sprays; enclosure and fabric filter with 99% control of Fuel Process Buildings 1 and 2, Tripper Deck Day Silos 1 – 5. Yellow Pine proposed enclosure and fabric filter with 99% control for the fly ash silo. Application 17700 speaks of economic impacts, however no economic analysis was provided.

EPD Review – Particulate matter less than 10 micrometers in diameter ($PM_{10}$) Emissions Control
The Division has determined that Yellow Pine's proposal to use of control technologies as described above to minimize the emissions of particulate matter emissions does not constitute BACT.

*Step 1: Identify all control technologies*

The Division agrees with the proposed control technologies.

*Step 2: Eliminate technically infeasible options*

The Division agrees with the proposed technically infeasible determinations.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

Although no control technologies are ranked by Yellow Pine, the Division has determined that control ranking is not warranted.

*Step 4: Evaluating the Most Effective Controls and Documentation*

The Division has determined that Yellow Pine's proposal to use water sprays, enclosures, and fabric filters as proposed to minimize the emissions of $PM_{10}$ does not constitute BACT. Yellow Pine must install high efficient fabric baghouses with a control efficiency of 99.9%. Water sprays and enclosures must be 90% efficient. In addition, the ash silo must be equipped with a closed vent system that vents back to the silo to reduce emissions during loading and unloading processes. In addition, an opacity limit of five percent will be imposed to ensure that particulate emissions from these processes remain at a minimum.

*Step 5: Selection of BACT*

BACT is as described above in Step 4.

<u>Conclusion – Particulate matter less than 10 micrometers in diameter ($PM_{10}$) Control</u>
The BACT selection for the Material Storage and Handling [Fuel Process Buildings 1 and 2 (FPB 1 and FPB 2), Tripper Deck Day Silos 1-5 (TDS 1-5), Fuel Storage Silo (SLO), and Fly Ash Silo (AS)] is summarized below in Table 4-21:

**Table 4-12: BACT Summary for the Material Storage and Handling [Fuel Process Buildings 1 and 2 (FPB 1 and FPB 2), Tripper Deck Day Silos 1-5 (TDS 1-5), Fuel Storage Silo, (SLO), and Fly Ash Silo (AS)]**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| $PM_{10}$ | Fabric Filter and enclosures with for the Fuel Process Buildings 1 and 2, Tripper Deck Day Silos 1 – 5, fuel storage silo, and the fly ash silo | None | None | Performance Testing and Monitoring |
| Opacity | None | 5 % | As specified by 40 CFR Part 60, Subpart OOO as applicable | Performance testing and monitoring |
| $PM_{10}$ | Closed Vent System on the fly ash silo | None | None | Monitoring |
| $PM_{10}$ | Water sprays for the Fuel Process Buildings 1 and 2, fuel storage silo, and Tripper Deck Day Silos 1 – 5 | None | None | Monitoring |

**Material Storage and Handling [Barge/Clamshell Unloading (BCU), Conveyor Transfer Towers 1-3 and 5-8 (CT 1-3 and 5-8), Biomass Storage Pile (BSP), Limestone Storage Pile (LSP), Sand Storage Pile (SSP), Plant Roads (PR), and Fly Ash Trucks (FT)] - Background**

The equipment listed above are the fugitive material (e.g. biomass, limestone, sand, and ash) storage and handling systems. It was proposed to be manufactured and installed in 2008. Primary emissions from this equipment are $PM_{10}$.

Because only $PM_{10}$ emissions increases from this equipment have triggered PSD applicability, only $PM_{10}$ emissions were evaluated for Best Available Control Technology (BACT).

Material Storage and Handling [Barge/Clamshell Unloading (BCU), Conveyor Transfer Towers 1-3 and 5-8 (CT 1-3 and 5-8), Biomass Storage Pile (BSP), Limestone Storage Pile (LSP), Sand Storage Pile (SSP), Plant Roads (PR), and Fly Ash Trucks (FT)] – Particulate matter less than 10 micrometers in diameter ($PM_{10}$) Emissions

Applicant's Proposal
In Application 17700, Yellow Pine evaluated pre and post combustion control technologies for the material storage and handling equipment listed above. The control technologies evaluated, verbatim as described in Application 17700, are as follows:

*Step 1: Identify all control technologies*

- Lower emitting processes and practices for the control of PM/PM-10 emissions are controls that lower the PM/PM-10 generation rate. Examples of lower emitting processes and practices for control of PM/PM-10 emissions include the conditioning of a material prior to transport, compacting storage piles, and limiting speeds on plant roads. Add-on controls prevent the release of PM/PM-10 or remove PM/PM-10 from the air. Water and surfactant sprays, surface sealants, and enclosures are examples of the implementation of add-on controls for PM/PM-10 emissions. Water and surfactant sprays control the creation of PM/PM-10 emissions by binding the smaller particles to the surface of the material, or by actively suppressing PM/PM-10 emissions through direct contact between spray droplets and PM/PM-10 within the air. Surface sealants are chemical treatments that create a protective layer on the surface of the material to bind and contain PM/PM-10. Enclosures control PM/PM-10 emissions by isolating the PM/PM-10 source from the environment. Examples of types of enclosures include material transfer chutes, conveyor hooding, and storage pile covers.

*Step 2: Eliminate technically infeasible options*

- Examples of technically infeasible applications would include the use of sprays that may cause a chemical reaction and application of water in freezing weather.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

Application 17700's ranking of remaining control technologies by control effectiveness is nonexistent.

*Step 4: Evaluating the Most Effective Controls and Documentation*

Application 17700's evaluation of the most effective controls and documentation is nonexistent.

*Step 5: Selection of BACT*

According to Application 17700, water sprays are proposed for Barge/Clamshell Unloading (Limestone and Sand) and biomass, limestone, and sand storage piles. Enclosures and water sprays are proposed for the conveyors. Enclosures are proposed for the transfer towers and fly ash truck loading. Telescopic chute and water sprays are proposed for the storage pile load-in (Biomass, Limestone, and Sand). Application 17700 speaks of economic impacts, however no economic analysis was provided.

<u>EPD Review – Particulate matter less than 10 micrometers in diameter ($PM_{10}$) Control</u>

*Step 1: Identify all control technologies*

The Division agrees with the proposed control technologies.

*Step 2: Eliminate technically infeasible options*

The Division agrees with the proposed technically infeasible determinations.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

Although no control technologies are ranked by Yellow Pine, the Division has determined that control ranking is not warranted.

*Step 4: Evaluating the Most Effective Controls and Documentation*

The Division has determined that Yellow Pine's proposal to use water sprays, enclosures, and telescopic chutes as proposed to minimize the emissions of $PM_{10}$ does not constitute BACT. However, water sprays, telescopic chutes, and enclosures must be 90% efficient. In addition, a vacuum ring on loading truck must be used to reduce emissions during loading and unloading processes. An opacity limit of 5% is also applicable.

*Step 5: Selection of BACT*

BACT is as described above in Step 4.

<u>Conclusion – Particulate matter less than 10 micrometers in diameter ($PM_{10}$) Control</u>

The BACT selection for the Material Storage and Handling [Barge/Clamshell Unloading (BCU), Conveyor Transfer Towers 1-3 and 5-8 (CT 1-3 and 5-8), Biomass Storage Pile (BSP), Limestone Storage Pile (LSP), Sand Storage Pile (SSP), Plant Roads (PR), and Fly Ash Trucks (FT)] is summarized below in Table 4-22:

**Table 4-13: BACT Summary for the Material Storage and Handling [Barge/Clamshell Unloading (BCU), Conveyor Transfer Towers 1-3 and 5-8 (CT 1-3 and 5-8), Biomass Storage Pile (BSP), Limestone Storage Pile (LSP), Sand Storage Pile (SSP), Plant Roads (PR), and Fly Ash Trucks (FT)]**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| $PM_{10}$ | water sprays for Barge/Clamshell Unloading (Limestone and Sand) and biomass, limestone, and sand storage piles | None | None | Monitoring |
| $PM_{10}$ | Enclosures and water sprays for the conveyors | None | None | Monitoring |
| $PM_{10}$ | Enclosures for the transfer towers and fly ash truck loading | None | None | Monitoring |
| $PM_{10}$ | Telescopic chute and water sprays for the storage pile load-in (Biomass, Limestone, and Sand). | None | None | Monitoring |
| $PM_{10}$ | Use of a vacuum ring on loading/unloading trucks | None | None | Monitoring |
| $PM_{10}$ | Opacity | 5% | As specified by 40 CFR Part 60, Subpart OOO | Performance Testing/Monitoring |

**<u>Cooling Tower (CT) - Background</u>**

Cooling water will circulate through the surface condenser to remove the heat released by the condensing steam and then will flow to the multi-cell mechanical draft cooling tower where heat will be rejected to the environment, primarily through evaporation of a portion of the cooling water. A very small portion of the cooling water may be carried into the ambient air in liquid form. This water is referred to as drift, and can contain a small amount of mineral matter that will be present in the cooling water. It was to be manufactured and installed in 2008. Primary emissions from this equipment are $PM_{10}$.

Because only $PM_{10}$ emissions increases from this equipment have triggered PSD applicability, only $PM_{10}$ emissions were evaluated for Best Available Control Technology (BACT).

Cooling Tower – Particulate matter less than 10 micrometers in diameter ($PM_{10}$) Emissions

Applicant's Proposal
In Application 17700, Yellow Pine evaluated pre and post combustion control technologies for the material storage and handling equipment listed above. The control technologies evaluated, verbatim as described in Application 17700, are as follows:

*Step 1: Identify all control technologies*

Application 17700 indicates that drift eliminators are the only control technology identified for limiting PM/PM-10 emissions from cooling towers.

*Step 2: Eliminate technically infeasible options*

Application 17700's elimination of technically infeasible options is nonexistent.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

Application 17700's ranking of remaining control technologies by control effectiveness is nonexistent.

*Step 4: Evaluating the Most Effective Controls and Documentation*

Application 17700's evaluation of the most effective controls and documentation is nonexistent.

*Step 5: Selection of BACT*

According to Application 17700, the use of current technology drift eliminators on the cooling tower represents BACT for the control of cooling tower fugitive PM/PM-10 emissions. The proposed BACT emission limit is equal to the mass flow rate of drift that would correspond to a drift eliminator effectiveness of 0.001%. Application 17700 speaks of economic impacts, however no economic analysis was provided.

EPD Review – Particulate matter less than 10 micrometers in diameter ($PM_{10}$) Control
*Step 1: Identify all control technologies*

The Division agrees with the proposed control technologies.

*Step 2: Eliminate technically infeasible options*

The Division agrees with the proposed technically infeasible determinations.

*Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

Although no control technologies are ranked by Yellow Pine, the Division has determined that control ranking is not warranted.

*Step 4: Evaluating the Most Effective Controls and Documentation*

The Division agrees with the proposed most effective controls and documentation evaluation.

*Step 5: Selection of BACT*

The Division has determined that Yellow Pine's proposal to use a mass flow rate of drift to meeting a drift eliminator effectiveness of 0.001% to minimize the emissions of $PM_{10}$ does constitute BACT.

Conclusion – Particulate matter less than 10 micrometers in diameter ($PM_{10}$) Control
The BACT selection for the Cooling Tower is summarized below in Table 4-23:

**Table 4-14: BACT Summary for the Cooling Tower**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| $PM_{10}$ | drift eliminators | mass flow rate of drift to meeting a drift eliminator effectiveness of 0.001% | None | Vendor Certification and Specification |

## Emergency Generator and Firewater Pump (EG and FP) - Background

The Facility will have a small emergency generator that will be used to keep the control room and certain essential equipment energized, awaiting a restart. The facility will also have an emergency diesel firewater pump. During normal operation, the power supply from the facility or the transmission line (back-up) would run the firewater system. Generally, the fuel storage areas must be monitored for fire and re-wetted from time to time, which also reduces dust. If both power sources fail, the emergency pump will be available to maintain water pressure of the fire water systems. They were to be manufactured and installed in 2008. Primary emissions from this equipment are $NO_x$, $SO_2$, $H_2SO_4$, PM, and $PM_{10}$.

Application 17700 does not contain BACT analysis or emission estimates for this equipment. Therefore the Division must determine BACT for this equipment. The Division has determined that the emergency generator's and firewater pump's compliance with 40 CFR Part 60, Subpart IIII constitutes BACT as they are limited use equipment.

## Fuel Storage Tanks - Background

The facility will use fuel storage tanks as described above to store fuel used at the facility. They were to be manufactured and installed in 2008. Primary emissions from this equipment are VOC.

Application 17700 does not contain BACT analysis or emission estimates for this equipment. Therefore the Division must determine BACT for this equipment. The primary source of VOC emissions are the operating losses and maintenance of the storage tanks. Application 17700 is silent about tank construction data such as the roof type. The Division has determined that the use conservation vents and proper maintenance and operating practices as specified by the manufacturer shall be considered as BACT. In addition, each tank must be equipped with submerged fuel fill pipes to filling process. Operating practices shall be maintained in a manual and updated as applicable. These manuals shall be made available for Division review upon request.

Conclusion – Volatile Organic Compounds (VOCs) Control

The BACT selection for the fuel storage tanks is summarized below in Table 4-29:

**Table 4-15: BACT Summary for the Fuel Storage Tanks**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| VOC | Conservation vents and proper operating and maintenance practices as specified by the manufacturer for fuel storage tank | None | None | Monitoring |
| VOC | Submerged fuel fill pipes on each fuel storage tank | None | None | None |

# 5.0 TESTING AND MONITORING REQUIREMENTS

Testing Requirements:

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*
In conducting the performance tests required under §60.8, Yellow Pine must use the methods and procedures in appendix A (including fuel certification and sampling) of 40 CFR Part 60 or the methods and procedures as specified in 40 CFR 60.45b, except as provided in §60.8(b). Section 60.8(f) does not apply to 40 CFR 60.45b. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Division [40 CFR 60.45(b)].

Compliance with the $SO_2$ emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for $SO_2$ for 30 successive fluidized bed boiler operating days, except as provided under paragraph (d) of 40 CFR 60.45b. A separate performance test is completed at the end of each fluidized bed boiler operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for $SO_2$ are calculated to show compliance with the standard [40 CFR 60.45b(g)]. Per the BACT requirements discussed above, compliance with the applicable $SO_2$ emission limit will be demonstrated by the required $SO_2$ CEMs.

Except as provided under paragraph (i) of 40 CFR 60.45b, the owner or operator of an affected facility shall use all valid $SO_2$ emissions data in calculating $\%P_s$ and $E_{ho}$ under paragraph (c), of 40 CFR 60.45b whether or not the minimum emissions data requirements under §60.46b are achieved. All valid emissions data, including valid $SO_2$ emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating $\%P_s$ and $E_{ho}$ pursuant to paragraph (c) of 40 CFR 60.45b[40 CFR 60.45b(h)].

Compliance with the PM emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of 40 CFR 60.46b, except as provided in paragraph (i) of 40 CFR 60.46b. To determine compliance with the PM emission limits and opacity limits under §60.43b, Yellow Pine must conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Division, using the following procedures and reference methods [40 CFR 60.46(d)(1) through (d)(7)]:

- Method 3B of appendix A of 40 CFR Part 60 is used for gas analysis when applying Method 5 or 17 of appendix A of 40 CFR Part 60.

- Method 5, 5B, or 17 of appendix A of 40 CFR Part 60 to measure the concentration of PM as follows:

    - Method 5 of appendix A of 40 CFR Part 60 shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

    - Method 17 of appendix A of 40 CFR Part 60 may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (32 °F). The procedures of sections 2.1 and 2.3 of Method 5B of appendix A of 40 CFR Part 60 may be used in Method 17 of appendix A of 40 CFR Part 60 only if it is used after a wet FGD system. Yellow Pine cannot use Method 17 of appendix A of 40 CFR Part 60 after wet FGD systems if the effluent is saturated or laden with water droplets.

    - Method 5B of appendix A of 40 CFR Part 60 is to be used only after wet FGD systems.

- Method 1 of appendix A of 40 CFR Part 60 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Division when necessitated by process variables or other factors.

- For Method 5 of appendix A of 40 CFR Part 60, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

- For determination of PM emissions, the oxygen ($O_2$) or $CO_2$ sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of 40 CFR Part 60 by traversing the duct at the same sampling location.

- For each run using Method 5, 5B, or 17 of appendix A of 40 CFR Part 60, the emission rate expressed in ng/J heat input is determined using:

    - The $O_2$ or $CO_2$ measurements and PM measurements obtained under 40 CFR 60.46;

    - The dry basis F factor; and

    - The dry basis emission rate calculation procedure contained in Method 19 of appendix A of 40 CFR Part 60.

- Method 9 of appendix A of 40 CFR Part 60 is used for determining the opacity of stack emissions (compliance will be demonstrated by the COMs required by BACT).

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*

If Yellow Pine seeks to demonstrate compliance with the fuel oil sulfur limits for the auxiliary boiler under §60.42c based on shipment fuel sampling, the initial performance test will consist of sampling and analyzing the oil in the initial tank of oil to be fired in the auxiliary boiler to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, Yellow Pine will have to sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2) [40 CFR 60.44c (g)]. If, however, Yellow Pine proposes to demonstrate compliance with the $SO_2$ standards based on fuel supplier certification, the performance test shall consist of the certification, the certification from the fuel supplier, as described under §60.48c(f), as applicable [40 CFR 60.44c (h)].

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants*

Yellow Pine must determine compliance with the particulate matter standards in §60.672(a) (any transfer point on belt conveyors or from any other affected facility any stack emissions) as follows: (1) Method 5 or Method 17 shall be used to determine the particulate matter concentration. The sample volume shall be at least 1.70 dscm (60 dscf). For Method 5, if the gas stream being sampled is at ambient temperature, the sampling probe and filter may be operated without heaters. If the gas stream is above ambient temperature, the sampling probe and filter may be operated at a temperature high enough, but no higher than 121 °C (250 °F), to prevent water condensation on the filter, and (2) Method 9 and the procedures in §60.11 shall be used to determine opacity [40 CFR 60.675(b)].

In determining compliance with the particulate matter standards in §60.672 (b) (any transfer point on belt conveyors or from any other affected equipment any fugitive emissions) and (c) (from any crusher, at which a capture system is not used, fugitive emissions), Yellow Pine must use Method 9 and the procedures in §60.11, with the following additions:

- The minimum distance between the observer and the emission source shall be 4.57 meters (15 feet).

- The observer shall, when possible, select a position that minimizes interference from other fugitive emission sources (e.g., road dust). The required observer position relative to the sun (Method 9, Section 2.1) must be followed.

- For affected facilities using wet dust suppression for particulate matter control, a visible mist is sometimes generated by the spray. The water mist must not be confused with particulate matter emissions and is not to be considered a visible emission. When a water mist of this nature is present, the observation of emissions is to be made at a point in the plume where the mist is no longer visible [40 CFR 60.675(c)(1)].

In determining compliance with the opacity of stack emissions from any baghouse that controls emissions only from an individual enclosed storage bin under §60.672(f), using Method 9, the duration of the Method 9 observations shall be 1 hour (ten 6-minute averages) [40 CFR 60.675(c)(2)].

When determining compliance with the fugitive emissions standard for any affected facility described under §60.672(b), the duration of the Method 9 observations may be reduced from 3 hours (thirty 6-minute averages) to 1 hour (ten 6-minute averages) only if the following conditions apply: (1) There are no individual readings greater than 10 percent opacity; and (2) There are no more than 3 readings of 10 percent for the 1-hour period [40 CFR 60.675(c)(3)].

When determining compliance with the fugitive emissions standard for any crusher at which a capture system is not used as described under §60.672(c), the duration of the Method 9 observations may be reduced from 3 hours (thirty 6-minute averages) to 1 hour (ten 6-minute averages) only if the following conditions apply: (1) There are no individual readings greater than 15 percent opacity; and (2) There are no more than 3 readings of 15 percent for the 1-hour period [40 CFR 60.675(c)(4)].

In determining compliance with any transfer point on a conveyor belt or any other affected equipment enclosed in a building subject §60.672(e), Yellow Pine must use Method 22 to determine fugitive emissions. The performance test shall be conducted while all affected facilities inside the building are operating. The performance test for each building shall be at least 75 minutes in duration, with each side of the building and the roof being observed for at least 15 minutes [40 CFR 60.675(d)].

Yellow Pine may use the alternatives to the reference methods and procedures specified in 40 CFR 60.675(e). To comply with §60.676(d), Yellow Pine must record the measurements as required in §60.676(c) using the monitoring devices in §60.674 (a) and (b) during each particulate matter run and shall determine the averages [40 CFR 60.675(f)]. Initial Method 9 performance tests under §60.11 of this part and §60.675 of this subpart are not required for: (1) Wet screening operations and subsequent screening operations, bucket elevators, and belt conveyors that process saturated material in the production line up to, but not including the next crusher, grinding mill or storage bin, or (2) Screening operations, bucket elevators, and belt conveyors in the production line downstream of wet mining operations, that process saturated materials up to the first crusher, grinding mill, or storage bin in the production line[40 CFR 60.675(h)].

*Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 63) National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j)*

<u>*Fluidized Bed Boiler*</u>

Discussion of applicable testing can be found in Appendix A.

*Auxiliary Boiler*

Discussion of applicable testing can be found in Appendix A.

*Part 75, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 75) Continuous Emissions Monitoring*

The following table summarizes applicable test methods associated with this regulation.

**Table 5-1: 40 CFR Part 75 Testing Requirements for the Fluidized Bed Boiler**

| Pollutant/Parameter | Required Testing | Testing Method | Regulatory Authority |
|---|---|---|---|
| Sampling Port Location and Traverses | Sampling Port Location and Traverses | Method 1 or 1A in Appendix A of Part 60 | 75.22(a)(1) |
| Velocity and Volumetric Flow | Velocity and Volumetric Flow | Methods 2 or its allowable alternatives, as provided in appendix A to part 60 of r, except for Methods 2B and 2E in Appendix A of Part 60 | 75.22(a)(2) |
| $O_2$ and $CO_2$ Concentrations | $O_2$ and $CO_2$ Concentrations | Methods 3, 3A, or 3B in Appendix A of Part 60 | 75.22(a)(3) |
| Moisture Content | Moisture Content | Method 4 (either the standard procedure described in section 8.1 of the method or the moisture approximation procedure described in section 8.2 of the method) shall be used to correct pollutant concentrations from a dry basis to a wet basis (or from a wet basis to a dry basis) and shall be used when relative accuracy test audits of continuous moisture monitoring systems are conducted. For the purpose of determining the stack gas molecular weight, however, the alternative wet bulb-dry bulb technique for approximating the stack gas moisture content described in section 2.2 of Method 4 may be used in lieu of the procedures in sections 8.1 and 8.2 of the method in Appendix A of Part 60 | 75.22(a)(4) |

| Pollutant/Parameter | Required Testing | Testing Method | Regulatory Authority |
|---|---|---|---|
| $SO_2$ and $NO_x$ Emissions | $SO_2$ and $NO_x$ Emissions | Methods 6, 6A, 6B or 6C, and 7, 7A, 7C, 7D or 7E in appendix A-4 to part 60, as applicable, are the reference methods for determining $SO_2$ and $NO_X$ pollutant concentrations. (Methods 6A and 6B in appendix A–4 to part 60 may also be used to determine $SO_2$ emission rate in lb/mmBtu.) Methods 7, 7A, 7C, 7D, or 7E in appendix A–4 to part 60 must be used to measure total $NO_X$ emissions, both NO and $NO_2$, for purposes of this part. The owner or operator shall not use the sections, exceptions, and options of method 7E in appendix A–4 to part 60 as specified in 75.22(a)(5). | 75.22(a)(5) |
| Backup monitoring system to provide quality-assured monitor data | $O_2$ and $CO_2$ Concentrations | Methods 3A in Appendix A of Part 60 | 75.22(b)(1) |
| $SO_2$ Concentrations | $SO_2$ Concentrations | Methods 6C in Appendix A of Part 60 | 75.22(b)(2) |
| $NO_x$ Concentrations | $NO_x$ Concentrations | Methods 7E in Appendix A of Part 60 | 75.22(b)(3) |
| Moisture Content | Moisture Content | Method 2, or its allowable alternatives, as provided in appendix A to part 60 of this chapter, except for Methods 2B and 2E, for determining volumetric flow. The sample point(s) for reference methods shall be located according to the provisions of section 6.5.5 of appendix A to this part. | 75.22(b)(4) |
| Calibration Gases | Calibration gases as defined in section 5 of appendix A to Part 75 | Methods 3A, 6C, and 7E in appendices A–2 and A–4 of part 60 | 75.22(c)(6) |

*Part 52.21, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 52.21) Prevention of Significant Deterioration*

<u>*Fluidized Bed Boiler*</u>

The proposed boilers are subject to several parallel sets of requirements. In this case, results in testing and monitoring requirements are redundant and unnecessary as a practical matter, even though the requirements still legally apply to the source. In EPA's Part 70 White Paper #2[12],

> "In cases where compliance with a single set of requirements effectively assures compliance with all requirements, compliance with all elements of each of the overlapping requirements may be unnecessary and could needlessly consume resources . . . .The streamlined monitoring, record keeping, and reporting requirements would generally be those associated with the most stringent emissions limit, providing they would assure compliance to the same extent as any subsumed monitoring. Thus, monitoring, record keeping, or reporting to determine compliance with subsumed limits would not be required where the source implements the streamlined approach."

The table below illustrates the individual applicable testing requirements for the proposed project:

**Table 5-2: Applicable Testing Requirements for the Fluidized Bed Boiler**

| **Pollutant/Parameter** | **40 CFR Part 60 Subpart Db** | **40 CFR Parts 72, 73, 75, and 77** | **40 CFR Part 52.21 and 40 CFR Part 63 Subpart B** |
|---|---|---|---|
| Transverse Points | Method 1 in Appendix A of Part 60 | Method 1 or 1A in Appendix A of Part 60 | Method 1 in Appendix A of Part 60 |
| $O_2$ concentration | Methods 3, 3A, 3B, or 3C in Appendix A of Part 60 | Methods 3, 3A, or 3B in Appendix A of Part 60 | Methods 3, 3A, or 3B in Appendix A of Part 60 |
| $CO_2$ concentration | Methods 3, 3A, 3B, or 3C in Appendix A of Part 60 | Methods 3, 3A, or 3B in Appendix A of Part 60 | Methods 3, 3A, or 3B in Appendix A of Part 60 |
| Backup monitoring system to provide quality-assured monitor data for $O_2$ and $CO_2$ Concentrations | Not Applicable | Methods 3A in Appendix A of Part 60 | Methods 3A in Appendix A of Part 60 |
| $SO_2$ concentration | Methods 6, 6A, 6B or 6C, in appendix A-4 to part 60, as applicable, are the reference methods for determining $SO_2$ pollutant concentrations. | Methods 6, 6A, 6B or 6C, in appendix A-4 to part 60, as applicable, are the reference methods for determining $SO_2$ pollutant concentrations. | Methods 6, 6A, 6B or 6C, in appendix A-4 to part 60, as applicable, are the reference methods for determining $SO_2$ pollutant concentrations. |

[12] *White Paper # 2 for Improved Implementation of the Part 70 Operating Permits Program*, EPA, Office of Air Quality Planning and Standards, March 5, 1996.

| Pollutant/Parameter | 40 CFR Part 60 Subpart Db | 40 CFR Parts 72, 73, 75, and 77 | 40 CFR Part 52.21 and 40 CFR Part 63 Subpart B |
|---|---|---|---|
| Backup monitoring system to provide quality-assured monitor data for $SO_2$ concentrations | Not Applicable | Methods 6C in Appendix A of Part 60 | Methods 6C in Appendix A of Part 60 |
| Percent reduction (%$R_f$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and fly ash interactions. | Method 19 of appendix A of 40 CFR Part 60 | Not Applicable | Method 19 of appendix A of 40 CFR Part 60 |
| Determine the percent $SO_2$ reduction (%$R_g$) of any $SO_2$ control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system. | Method 19 of appendix A of 40 CFR Part 60 | Not Applicable | Method 19 of appendix A of 40 CFR Part 60 |
| $SO_2$ Emission Rate | Method 19 of appendix A of 40 CFR Part 60 | Methods 6A and 6B in appendix A–4 to part 60 may also be used to determine $SO_2$ emission rate in lb/mmBtu.) | Method 19 of appendix A of 40 CFR Part 60/ Methods 6A and 6B in appendix A–4 to part 60 may also be used to determine $SO_2$ emission rate in lb/mmBtu. |
| $SO_2$ and $CO_2$, or $O_2$ concentrations | CEMS in §60.47b(a) | CEMS in §75.20(c)(1) | CEMs to meet the requirements of §60.47b(a) and §75.20(c)(1) |
| $SO_2$ CEMS Installation and Certification | If $SO_2$ CEMS installed and certified according to the requirements of §75.20(c)(1) and appendix A to 40 CFR Part 75, and is continuing to meet the ongoing quality assurance requirements of §75.21 and appendix B to 40 CFR Part 75, that CEMS may be used to meet the requirements of 40 CFR 60.49Db provided that all requirements of 40 CFR 60.49b(a) are met. | Installed and certified according to the requirements of §75.20(c)(1) and appendix A to 40 CFR Part 75 | If $SO_2$ CEMS installed and certified according to the requirements of §75.20(c)(1) and appendix A to 40 CFR Part 75, and is continuing to meet the ongoing quality assurance requirements of §75.21 and appendix B to 40 CFR Part 75, that CEMS may be used to meet the requirements of 40 CFR 60.49Db provided that all requirements of 40 CFR 60.49b(a) are met. |

| Pollutant/Parameter | 40 CFR Part 60 Subpart Db | 40 CFR Parts 72, 73, 75, and 77 | 40 CFR Part 52.21 and 40 CFR Part 63 Subpart B |
|---|---|---|---|
| $SO_2$ CEMS Span Values | As specified in 40 CFR 60.47b(e), $SO_2$ span values shall be determined according to section 2.1.1 in appendix A to 40 CFR Part 75 | $SO_2$ span values shall be determined according to section 2.1.1 in appendix A to 40 CFR Part 75 | As specified in 40 CFR 60.47b(e), $SO_2$ span values shall be determined according to section 2.1.1 in appendix A to 40 CFR Part 75 |
| $SO_2$ Calibration Gas Mixtures | As specified in 40 CFR 60.47b(e) | [Calibration Gas as defined in section 5 of appendix A to Part 75] Methods 3Aand 6C in appendices A–2 and A–4 of part 60 | As specified in 40 CFR 60.47b(e)/[Calibration Gas as defined in section 5 of appendix A to Part 75] Methods 3A and 6C in appendices A–2 and A–4 of part 60 |
| COMs Performance | Performance Specification 1 in 40 CFR part 60, appendix B. | Performance Specification 1 in 40 CFR part 60, appendix B. | Performance Specification 1 in 40 CFR part 60, appendix B. |
| PM Emission Rate | The dry basis F factor ($O_2$) procedures in Method 19 of appendix A of 40 CFR Part 60 | Not Applicable | The dry basis F factor ($O_2$) procedures in Method 19 of appendix A of t40 CFR Part 60 |
| PM Emission Rate | The $F_c$ factor ($CO_2$) procedures in Method 19 of appendix A of 40 CFR Part 60 may be used to compute the emission rate of PM under the stipulations of §60.46(d)(1). The $CO_2$ shall be determined in the same manner as the $O_2$ concentration. | Not Applicable | The $F_c$ factor ($CO_2$) procedures in Method 19 of appendix A of 40 CFR Part 60 may be used to compute the emission rate of PM under the stipulations of §60.46(d)(1). The $CO_2$ shall be determined in the same manner as the $O_2$ concentration. |
| PM Concentration | Method 5 of appendix A of 40 CFR Part 60 shall be used at affected facilities without wet FGD systems and Method 5B of appendix A of 40 CFR Part 60 shall be used after wet FGD systems. | Not Applicable | Method 5 of appendix A of 40 CFR Part 60 shall be used at affected facilities without wet FGD systems and Method 5B of appendix A of 40 CFR Part 60 shall be used after wet FGD systems. |
| PM Concentration | Method 5 or 5B of appendix A of this part, Method 17 of appendix A of this part may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C | Not Applicable | Method 5 or 5B of appendix A of this part, Method 17 of appendix A of this part may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 |

| Pollutant/Parameter | 40 CFR Part 60 Subpart Db | 40 CFR Parts 72, 73, 75, and 77 | 40 CFR Part 52.21 and 40 CFR Part 63 Subpart B |
|---|---|---|---|
| | (320 °F). The procedures of §§2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after wet FGD systems. Method 17 of appendix A of this part shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets. | | °F). The procedures of §§2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after wet FGD systems. Method 17 of appendix A of this part shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets. |
| Velocity and Volumetric Flow | Not Applicable | Methods 2 or its allowable alternatives, as provided in appendix A to part 60 of r, except for Methods 2B and 2E in Appendix A of Part 60 | Methods 2 or its allowable alternatives, as provided in appendix A to part 60 of r, except for Methods 2B and 2E in Appendix A of Part 60 |
| Moisture Content | Not Applicable | Method 4 (either the standard procedure described in section 8.1 of the method or the moisture approximation procedure described in section 8.2 of the method) shall be used to correct pollutant concentrations from a dry basis to a wet basis (or from a wet basis to a dry basis) and shall be used when relative accuracy test audits of continuous moisture monitoring systems are conducted. For the purpose of determining the stack gas molecular weight, however, the alternative wet bulb-dry bulb technique for approximating the stack gas moisture content described in section 2.2 of Method | Method 4 (either the standard procedure described in section 8.1 of the method or the moisture approximation procedure described in section 8.2 of the method) shall be used to correct pollutant concentrations from a dry basis to a wet basis (or from a wet basis to a dry basis) and shall be used when relative accuracy test audits of continuous moisture monitoring systems are conducted. For the purpose of determining the stack gas molecular weight, however, the alternative wet bulb-dry bulb technique for approximating the stack gas moisture content described in section 2.2 of Method 4 may be used in lieu of the procedures in sections 8.1 and 8.2 of the method. in Appendix A of Part 60 |

| Pollutant/Parameter | 40 CFR Part 60 Subpart Db | 40 CFR Parts 72, 73, 75, and 77 | 40 CFR Part 52.21 and 40 CFR Part 63 Subpart B |
|---|---|---|---|
| | | 4 may be used in lieu of the procedures in sections 8.1 and 8.2 of the method in Appendix A of Part 60 | |
| Moisture Content | Not Applicable | Method 2, or its allowable alternatives, as provided in appendix A to part 60 of this chapter, except for Methods 2B and 2E, for determining volumetric flow. The sample point(s) for reference methods shall be located according to the provisions of section 6.5.5 of appendix A to this part. | Method 2, or its allowable alternatives, as provided in appendix A to part 60 of this chapter, except for Methods 2B and 2E, for determining volumetric flow. The sample point(s) for reference methods shall be located according to the provisions of section 6.5.5 of appendix A to this part. |
| $NO_x$ Emission Rate | Not Applicable | Not Applicable | Method 19 of appendix A of 40 CFR Part 60 |
| $NO_x$ and $CO_2$ or $O_2$ concentrations | Not Applicable | CEMS in §75.20(c)(1) | CEMS in §75.20(c)(1) |
| $NO_x$ CEMS Installation and Certification | Not Applicable | 40 CFR Part 75 | 40 CFR Part 75 |
| $NO_x$ concentration | Not Applicable | Methods 7, 7A, 7C, 7D or 7E in appendix A-4 to part 60, as applicable, are the reference methods for determining $NO_x$ Method 7 of appendix A of 40 CFR Part 60 shall be used to determine the $NO_X$ concentration at the same location as the $NO_X$ monitor pollutant concentrations. | Methods 7, 7A, 7C, 7D or 7E in appendix A-4 to part 60, as applicable, are the reference methods for determining $NO_x$ Method 7 of appendix A of 40 CFR Part 60 shall be used to determine the $NO_X$ concentration at the same location as the $NO_X$ monitor pollutant concentrations. |
| $NO_x$ concentration | Not Applicable | Not Applicable | Method 7A, 7C, 7D, or 7E of appendix A of 40 CFR Part 60 |
| $NO_x$ Emission Rate | Not Applicable | Methods 7, 7A, 7C, 7D, or 7E in appendix A–4 to part 60 must be used to measure total $NO_x$ emissions, both NO and $NO_2$, for purposes of this part. | Methods 7, 7A, 7C, 7D, or 7E in appendix A–4 to part 60 must be used to measure total $NO_x$ emissions, both NO and $NO_2$, for purposes of this part. The owner or operator |

| Pollutant/Parameter | 40 CFR Part 60 Subpart Db | 40 CFR Parts 72, 73, 75, and 77 | 40 CFR Part 52.21 and 40 CFR Part 63 Subpart B |
|---|---|---|---|
| | | The owner or operator shall not use the sections, exceptions, and options of method 7E in appendix A–4 to part 60 as specified in 75.22(a)(5). | shall not use the sections, exceptions, and options of method 7E in appendix A–4 to part 60 as specified in 75.22(a)(5). |
| Backup monitoring system to provide quality-assured monitor data for NOx concentrations | Not Applicable | Method 7E in Appendix A of Part 60 | Method 7E in Appendix A of Part 60 |
| $NO_x$ Calibration Gas Mixtures | Not Applicable | [Calibration Gas as defined in section 5 of appendix A to Part 75] Methods 3A and 7E in appendices A–2 and A–4 of part 60 | [Calibration Gas as defined in section 5 of appendix A to Part 75] Methods 3A and 7E in appendices A–2 and A–4 of part 60 |
| $NO_x$ CEMs Span Values | Not Applicable | Section 2.1.2 in appendix A to 40 CFR Part 75 | Section 2.1.2 in appendix A to 40 CFR Part 75 |
| Hg Concentration | Not Applicable | Not Applicable | Method 29 in Appendix A to 40 CFR Part 60 |
| Hg Emission Rate | Not Applicable | Not Applicable | Method 19 F-Factor methodology in Appendix A of Part 60 |
| Opacity | Method 9 | Not Applicable | Method 9 |
| Biomass Moisture Content | Not Applicable | Not Applicable | ASTM E871-82 (2006) or approved equivalent |
| TDF Moisture Content | Not Applicable | Not Applicable | ASTM D6700-01(2006) , or approved equivalent |
| Heat content of biomass | Not Applicable | Not Applicable | ASTM E711-8, or approved equivalent |
| Biomass ash content | Not Applicable | Not Applicable | ASTM D1102-84(2007) , or approved equivalent |
| Biomass sulfur content | Not Applicable | Not Applicable | ASTM E775-87(2004) , or approved equivalent |
| Volatile Organic Compounds Concentration | Not Applicable | Not Applicable | Method 25 of 40 CFR Part 60 Appendix A |
| Volatile Organic Compounds Emission Rate | Not Applicable | Not Applicable | Method 19 F-Factor methodology in Appendix A of Part 60 |
| Silver (Ag) Concentration* | Not Applicable | Not Applicable | Method 29 in Appendix A to 40 CFR Part 60 |
| Ag Emission Rate* | Not Applicable | Not Applicable | Method 19 F-Factor methodology in Appendix A of Part 60 |

| Pollutant/Parameter | 40 CFR Part 60 Subpart Db | 40 CFR Parts 72, 73, 75, and 77 | 40 CFR Part 52.21 and 40 CFR Part 63 Subpart B |
|---|---|---|---|
| Hydrogen Chloride Concentration | Not Applicable | Not Applicable | Method 26 or Method 26A of 40 CFR Part 60 Appendix A |
| Hydrogen Chloride Emission Rate | Not Applicable | Not Applicable | Method 19 F-Factor methodology in Appendix A of Part 60 |
| Carbon Monoxide Concentration | Not Applicable | Not Applicable | Method 10 or Method 10B of 40 CFR Part 60 Appendix A |
| Carbon Monoxide Emission Rate | Not Applicable | Not Applicable | Method 19 F-Factor methodology in Appendix A of Part 60 |
| Lead Concentration | Not Applicable | Not Applicable | Method 29 of 40 CFR Part 60 Appendix A |
| Lead Emission Rate | Not Applicable | Not Applicable | Method 19 F-Factor methodology in Appendix A of Part 60 |

*Silver emissions testing is required to demonstrate compliance with the Georgia Toxics Guidelines discussed later in this document.

The SNCR, temperature indicator, $NO_x$ CEMS, and all required combustion control monitors discussed above must be installed and operating during testing. Yellow Pine must conduct testing to demonstrate compliance with applicable $PM_{10}$, Pb PSD avoidance, and 112(g) Hg emission limits using applicable test methods listed in Table 5.2. The fabric filter baghouse and all required combustion control monitors discussed above must be installed and operating during testing. Yellow Pine must conduct testing at the stack to demonstrate compliance with applicable 112(g) HCl requirements, using applicable test methods listed in Table 5.2. The dry scrubber system, $SO_2$ CEMs, and all required combustion control monitors discussed above must be installed and operating during testing. Yellow Pine must conduct testing to demonstrate compliance with applicable Hg 112(g) using applicable test methods listed in Table 5.2. The fabric filter baghouse, SNCR for $NO_x$ control, and scrubber system for $SO_2$ control must be installed and operating during testing. To demonstrate compliance with the applicable opacity limits, the COMs must be installed and operating during testing.

Yellow Pine must conduct performance tests for $PM_{10}$ emissions with the boiler operating at maximum load. The performance testing for $PM_{10}$ must be done initially as within the earliest timeframe specified by 40 CFR Part 60, Subpart Db. Performance testing shall be conducted as frequently as the most frequent testing required by this regulations, or every 12 months, at a minimum.

The Pb, HCl, Hg, and VOC emissions performance tests must be conducted with the boiler operating at maximum load. Initial performance tests are required to demonstrate compliance with the Pb, Hg, HCl, and VOC emission/operating limits. Initial performance testing for these pollutants must be conducted within 60 days after achieving the maximum production rate at which the boiler will be operated, but not later than 180 days after the initial startup of the boiler. Performance tests are required every 12 months thereafter.

During the performance tests for Pb, Hg, Ag, and $PM_{10}$ emissions, Yellow Pine must then determine, based on the 6-minute opacity averages, the opacity value corresponding to the 99 percent upper confidence level of a normal distribution of average opacity values at which the fluidized bed boiler complies with applicable limits.

During the performance tests for HCl emissions, Yellow Pine must determine the lime injection flow rate of dry scrubber system in terms of pounds per million Btu heat input at which the fluidized bed boiler complies with HCl emissions limit.

Testing shall be conducted in accordance with applicable test method and Division's *Procedures for Testing and Monitoring Sources of Air Pollutants*.

Auxiliary Boiler

To avoid testing redundancy, the Division has determined that the testing methods and frequency established for compliance with 40 CFR Part 60, Subpart Dc are also applicable under 40 CFR Part 52.21. Therefore, testing for the auxiliary boiler is as described above.

*Material Storage and Handling [Fuel Process Buildings 1 and 2 (FPB 1 and FPB 2), Tripper Deck Day Silos 1-5 (TDS 1-5),Fuel Storage Silo (SLO) and Fly Ash Silo (AS)]*

According to Application 17700, the Fuel Process Building 1, Tripper Deck Day Silos 1-5, and the Fly Ash Silo all process sand and limestone. Therefore, these sources are subject to 40 CFR Part 52.21, and 40 CFR Part 60 Subpart OOO. The most stringent limits and associated performance testing will apply. Therefore following limits and associated performance testing apply:

**Table 5-5: Applicable Testing Requirements for Material Storage and Handling [Fuel Process Buildings 1 and 2, Tripper Deck Day Silos 1-5, and Fly Ash Silo]**

| Equipment/Process | 40 CFR Part 60 Subpart OOO | 40 CFR Part 52.21 |
|---|---|---|
| Fuel Process Building 1 | Opacity of 7% / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 | Opacity of 5% / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 |
| | PM emissions totaling 0.05 g/dscm (0.022 gr/dscf) / EPA Method 5 or Method 17 of 40 CFR Part 60 Appendix A and 40 CFR 60.675(b) | Not Applicable |
| Tripper Deck Day Silos 1-5 | Opacity of 7% each / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 | Opacity of 5% each / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 |
| | PM emissions totaling 0.05 g/dscm (0.022 gr/dscf) / EPA Method 5 or Method 17 of 40 CFR Part 60 Appendix A and 40 CFR 60.675(b) | Not Applicable |

| Equipment/Process | 40 CFR Part 60 Subpart OOO | 40 CFR Part 52.21 |
|---|---|---|
| Fuel Storage Silo | Opacity of 7% / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 | Opacity of 7% / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 |
| | PM emissions totaling 0.05 g/dscm (0.022 gr/dscf) / EPA Method 5 or Method 17 of 40 CFR Part 60 Appendix A and 40 CFR 60.675(b) | Not Applicable |
| Fly Ash Silo | Opacity of 7% / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 | Opacity of 7% / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 |
| | PM emissions totaling 0.05 g/dscm (0.022 gr/dscf) / EPA Method 5 or Method 17 of 40 CFR Part 60 Appendix A and 40 CFR 60.675(b) | Not Applicable |
| Fuel Process Building 2 | Not Applicable | Opacity of 5% / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 |

Yellow Pine will be required to conduct initial performance testing for each pollutant and/or parameter listed in the table above, and conduct annual testing thereafter. All required control technologies (i.e. baghouse, enclosures, etc.) must be in place and operational at the time of testing. The required control technologies must be operated at all times.

*Material Storage and Handling [Barge/Clamshell Unloading (BCU), Conveyor Transfer Towers 1-3) and 5-8 (CT 1-3 and 5-8), Biomass Storage Pile (BSP), Limestone Storage Pile (LSP), Sand Storage Pile (SSP), Plant Roads (PR), and Fly Ash Trucks (FT)]*

According to Application 17700, the Barge/Clamshell Unloading (BCU), Conveyor Transfer Towers 1, 3 and 5, all process sand and limestone. The most stringent limits and associated performance testing will apply. Therefore, these sources are subject to 40 CFR Part 52.21and 40 CFR Part 60 Subpart OOO. Therefore, the following limits and associated performance testing apply:

**Table 5-6: Applicable Testing Requirements for Material Storage and Handling [Barge/Clamshell Unloading (BCU), Conveyor Transfer Towers 1-3 (not 2) and 5-8 (CT 1-3 and 5-8)(not 6, 7, 8), Biomass Storage Pile (BSP), Limestone Storage Pile (LSP), Sand Storage Pile (SSP), Plant Roads (PR), and Fly Ash Trucks (FT)]**

| Equipment/Process | 40 CFR Part 60 Subpart OOO | 40 CFR Part 52.21 |
|---|---|---|
| Barge/Clamshell Unloading | Opacity of 10% / EPA Method 9 of 40 CFR Part 60 Appendix A, the procedures in §60.11, and 40 CFR 60.675(c) | Opacity of 5% / EPA Method 9 of 40 CFR Part 60 Appendix A, the procedures in §60.11, and 40 CFR 60.675(c) and EPA Method 22 of 40 CFR Part 60 Appendix A |
| Conveyor Transfer Towers 1, 3, and 5 | Opacity of 10% each / EPA Method 9 of 40 CFR Part 60 Appendix A, the procedures in §60.11, and 40 CFR 60.675(c) | Opacity of 5% each / EPA Method 9 of 40 CFR Part 60 Appendix A, the procedures in §60.11, and 40 CFR 60.675(c) and EPA Method 22 of 40 CFR Part 60 Appendix A |
| Conveyor Transfer Towers 2, 6, 7, and 8 | Not Applicable | Opacity of 5% / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 and EPA Method 22 of 40 CFR Part 60 Appendix A |
| Biomass Storage Pile | Not Applicable | Opacity of 5% / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 and EPA Method 22 of 40 CFR Part 60 Appendix A |
| Limestone Storage Pile | Not Applicable | Opacity of 5% / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 and EPA Method 22 of 40 CFR Part 60 Appendix A |
| Sand Storage Pile | Not Applicable | Opacity of 5% / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 and EPA Method 22 of 40 CFR Part 60 Appendix A |
| Plant Roads | Not Applicable | Opacity of 5% / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 and EPA Method 22 of 40 CFR Part 60 Appendix A |

| Equipment/Process | 40 CFR Part 60 Subpart OOO | 40 CFR Part 52.21 |
|---|---|---|
| Fly Ash Trucks | Not Applicable | Opacity of 5% / EPA Method 9 of 40 CFR Part 60 Appendix A and the procedures in §60.11 and EPA Method 22 of 40 CFR Part 60 Appendix A |

Yellow Pine will be required to conduct initial performance testing for each pollutant and/or parameter listed in the table above, and conduct annual testing thereafter, with some exception. Yellow Pine must conduct EPA Method 22 monitoring on a weekly basis. If visible emissions are observed, the Method 9 monitoring must be completed within 24 hours. This requirement is in line with the compliance methods specified in the final permit issued to Deseret Power by EPA Region 8. All required control technologies (i.e. baghouse, enclosures, etc.) must be in place and operational at the time of testing. The required control technologies must be operated at all times.

*Cooling Tower (CT)*

There is no required performance testing for this equipment under 40 CFR Part 52.21.

*Emergency Generator and Firewater Pump (EG and FP)*

Performance testing and compliance demonstration for each of these sources must be conducted in accordance with 40 CFR Part 60, Subpart IIII.

*Fuel Storage Tanks*

According to Application 17700, the following are the proposed fuel storage tanks to be located at Yellow Pine:

- 100,000-gallon No. 2 Fuel Oil Storage Tank,
- 5,000-gallon Diesel Fuel Storage Tank,
- 25,000-gallon Ammonia (19% aqueous) Storage Tank,
- 500-gallon Diesel Fuel Storage Tank,
- 250-gallon Diesel Fuel Storage Tank, and
- 250-gallon Diesel Fuel Storage Tank.

There is no required performance testing for this equipment under 40 CFR Part 52.21.

Monitoring, Record Keeping, and Reporting Requirements:

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*

Except as provided in paragraphs (b), (f), and (h) of 40 CFR 60.47b, Yellow Pine must install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring $SO_2$ concentrations and either $O_2$ or $CO_2$ concentrations and shall record the output of the systems for the fluidized bed boiler. For units complying with the percent reduction standard, the $SO_2$ and either $O_2$ or $CO_2$ concentrations must both be monitored at the inlet and outlet of the $SO_2$ control device. If the owner or operator has installed and certified $SO_2$ and $O_2$ or $CO_2$ CEMS according to the requirements of §75.20(c)(1) of 40 CFR and appendix A to part 75 of 40 CFR, and is continuing to meet the ongoing quality assurance requirements of §75.21 of 40 CFR and appendix B to part 75 of 40 CFR, those CEMS may be used to meet the requirements of 40 CFR 60.47b, provided that:

- When relative accuracy testing is conducted, $SO_2$ concentration data and $CO_2$ (or $O_2$) data are collected simultaneously; and

- In addition to meeting the applicable $SO_2$ and $CO_2$ (or $O_2$) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

- The reporting requirements of §60.49b are met. $SO_2$ and $CO_2$ (or $O_2$) data used to meet the requirements of §60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the $SO_2$ data have been bias adjusted according to the procedures of part 75 of this chapter [40 CFR 60.47b(a)].

Yellow Pine must install a COMS to measure opacity of the fluidized bed boiler [40 CFR 60.47b(a)]. In place of PM testing with EPA Reference Method 5, 5B, or 17 of appendix A of 40 CFR, Yellow Pine may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere by the fluidized bed boiler and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 of appendix A of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(13) of 40 CFR 60.46(h)(2)(j). Except as provided in paragraph (j) of 40 CFR 60.48b, Yellow Pine must install, calibrate, maintain, and operate a CEMS for measuring the opacity of emissions discharged to the atmosphere and record the output of the system for the fluidized bed boiler [40 CFR 60.48b(a)]. Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a CEMS, and record the output of the system, for PM emissions discharged to the atmosphere as specified in §60.46b(j). The CEMS specified in paragraph §60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments [40 CFR 60.48b(k)]. Yellow Pine must follow the procedures under §60.13 for the installation, evaluation, and operation of the CEMS.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*

To demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, oil samples may be collected from the fuel tank for the auxiliary boiler immediately after the fuel tank is filled and before any oil is combusted. Yellow Pine must analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, Yellow Pine must ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less [40 CFR 60.46c(d)(2)]. Monitoring requirements of paragraphs (a) and (d) of 40 CFR 60.46c do not apply to the auxiliary boiler as it is subject to §60.42c(h)(1), where Yellow Pine seeks to demonstrate compliance with the $SO_2$ standards based on fuel supplier certification, as described under §60.48c(f), as applicable [40 CFR 60.46c(e)]. In accordance with 40 CFR 60.48c(g)(2), Yellow Pine must record and maintain records of the amount of each fuel combusted in the auxiliary boiler during each calendar month.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart Eb – Standards of Performance for Large Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994 or for Which Modification or Reconstruction is Commenced After June 19, 1996*

Yellow Pine must notify EPA of an exemption claim as discussed above. Yellow Pine must provide a copy of the federally enforceable permit that limits the firing of municipal solid waste to less than or equal to 30 percent of the weight of which is comprised, in aggregate, of municipal solid waste as measured on a calendar quarter basis and keep records of the amount of municipal solid waste fired on on a calendar quarter basis [40 CFR 60.50b(j)].

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants*

Monitoring shall be addressed under 40 CFR Part 52.21.

Yellow Pine must submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in §60.672, including reports of opacity observations made using Method 9 to demonstrate compliance with §60.672(b), (c), and (f), and reports of observations using Method 22 to demonstrate compliance with §60.672(e) [40 CFR 60.767(f)].

The owner or operator of any screening operation, bucket elevator, or belt conveyor that processes saturated material and is subject to §60.672(h) and subsequently processes unsaturated materials, shall submit a report of this change within 30 days following such change. This screening operation, bucket elevator, or belt conveyor is then subject to the 10 percent opacity limit in §60.672(b) and the emission test requirements of §60.11 and this subpart. Likewise a screening operation, bucket elevator, or belt conveyor that processes unsaturated material but subsequently processes saturated material shall submit a report of this change within 30 days following such change. This screening operation, bucket elevator, or belt conveyor is then subject to the no visible emission limit in §60.672(h) [40 CFR 60.767(g)].

The subpart A requirement under §60.7(a)(2) for notification of the anticipated date of initial startup of an affected facility shall be waived for owners or operators of affected facilities regulated under this 40 CFR Part 60 Subpart OOO but as specified in 40 CFR 60.767(h). The requirements of this section remain in force until and unless the Agency, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such States. In that event, affected facilities within the State will be relieved of the obligation to comply with the reporting requirements of this section, provided that they comply with requirements established by the State [40 CFR 60.767(j)].

*Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 63) National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [RICE]*
The 1500 kW emergency generator has a site rating of more than 500 brake Hp, and is located at a major source of HAP emissions. Therefore Yellow Pine must complete initial notification requirements of §63.6645(h) [40 CFR 63.6590(b)(i)].

*Part 75, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 75) Continuous Emissions Monitoring*
Yellow Pine meet the general operating requirements in §75.10 for an $SO_2$ continuous emission monitoring system and a flow monitoring system for fluidized bed boiler while the unit is combusting coal and/or any other fuel, except as provided in paragraph (e) of §75.11, in §75.16, and in subpart E of 40 CFR Part 75. Yellow Pine must use the requirements of 40 CFR 75.11(b) where $SO_2$ concentration is measured on a dry basis. Yellow Pine must use the requirements specified in 40 CFR 75.11(c) for a unit with no location for a flow monitor meeting siting requirements.

Yellow Pine must meet the general operating requirements in §75.10 for a $NO_X$ continuous emission monitoring system (CEMS) for each of the fluidized bed boilers, except as provided in paragraph (d) of §75.12, §75.17, and subpart E of 40 CFR Part 75. The diluent gas monitor in the $NO_X$-diluent CEMS may measure either $O_2$ or $CO_2$ concentration in the flue gases. Yellow Pine must use the requirements of 40 CFR 75.12 (b). If a correction for the stack gas moisture content is needed to properly calculate the $NO_X$ emission rate in lb/mmBtu, e.g., if the $NO_X$ pollutant concentration monitor measures on a different moisture basis from the diluent monitor, Yellow Pine must calculate hourly, quarterly, and annual $NO_X$ emission rates (in lb/mmBtu) by combining the $NO_X$ concentration (in ppm), diluent concentration (in percent $O_2$ or $CO_2$), and percent moisture (if applicable) measurements according to the procedures in appendix F to 40 CFR Part 75 [40 CFR 75.12(c)].

If Yellow Pine chooses to use the continuous emission monitoring method, then Yellow Pine must meet the general operating requirements in §75.10 for a $CO_2$ continuous emission monitoring system and flow monitoring system for the fluidized bed boiler. Yellow Pine shall comply with the applicable provisions specified in §§75.11(a) through (e) or §75.16, except that the phrase "$CO_2$ continuous emission monitoring system" shall apply rather than "$SO_2$ continuous emission monitoring system," the phrase "$CO_2$ concentration" shall apply rather than "$SO_2$ concentration," the term "maximum potential concentration of $CO_2$" shall apply rather than "maximum potential concentration of $SO_2$," and the phrase "$CO_2$ mass emissions" shall apply rather than "$SO_2$ mass emissions." [40 CFR 75.13(a)].

If Yellow Pine chooses to use the appendix G method for determining $CO_2$ emissions, then it must follow the procedures in appendix G to 40 CFR Part 75 for estimating daily $CO_2$ mass emissions based on the measured carbon content of the fuel and the amount of fuel combusted. For units with wet flue gas desulfurization systems or other add-on emissions controls generating $CO_2$, the owner or operator shall use the procedures in appendix G to 40 CFR Part 75 to estimate both combustion-related emissions based on the measured carbon content of the fuel and the amount of fuel combusted and sorbent-related emissions based on the amount of sorbent injected. The owner or operator must calculate daily, quarterly, and annual $CO_2$ mass emissions (in tons) in accordance with the procedures in appendix G to 40 CFR Part 75[40 CFR 75.13(b)].

If Yellow Pine chooses to use the appendix F method, then Yellow Pine shall determine hourly $CO_2$ concentration and mass emissions with a flow monitoring system; a continuous $O_2$ concentration monitor; fuel F and $F_c$ factors; and, where $O_2$ concentration is measured on a dry basis (or where Equation F–14b in appendix F to this part is used to determine $CO_2$ concentration), either, a continuous moisture monitoring system, as specified in §75.11(b)(2), or a fuel-specific default moisture percentage (if applicable), as defined in §75.11(b)(1); and by using the methods and procedures specified in appendix F to 40 CFR Part 75. For units using a common stack, multiple stack, or bypass stack, the owner or operator may use the provisions of §75.16, except that the phrase "$CO_2$ continuous emission monitoring system" shall apply rather than "$SO_2$ continuous emission monitoring system," the term "maximum potential concentration of $CO_2$" shall apply rather than "maximum potential concentration of $SO_2$," and the phrase "$CO_2$ mass emissions" shall apply rather than "$SO_2$ mass emissions." [40 CFR 75.13(c)].

Yellow Pine must meet the general operating provisions in §75.10 for a continuous opacity monitoring system for the fluidized bed boiler, except as provided in paragraphs (b), (c), and (d) of §75.14 and in §75.18. Each continuous opacity monitoring system shall meet the design, installation, equipment, and performance specifications in Performance Specification 1 in appendix B to 40 CFR Part 60 [40 CFR 75.14(a)].

Yellow Pine must follow the requirements of 40 CFR 75.20 for initial certification and recertification procedures. Yellow Pine must operate, calibrate and maintain each continuous emission monitoring system used to report emission data under the Acid Rain Program specified in 40 CFR 75.21(a). Yellow Pine must operate, calibrate, and maintain each continuous opacity monitoring system used under the Acid Rain Program according to the procedures specified for State Implementation Plans, pursuant to part 51, appendix M of Chapter 1. All calibration gases used to quality assure the operation of the instrumentation required by this part shall meet the definition in §72.2 of Chapter 1 [40 CFR 75.21(c)]. Yellow Pine or the designated representative shall submit a written notice of the dates of relative accuracy testing as specified in §75.61. Yellow Pine will invalidate data from a continuous emission monitoring system or continuous opacity monitoring system upon failure of an audit under appendix B to 40 CFR Part 75 or any other audit, beginning with the fluidized bed boiler operating hour of completion of a failed audit as determined by the Administrator. Yellow Pine shall not use invalidated data for reporting either emissions or heat input, nor for calculating monitor data availability [40 CFR 75.21(e)].

Yellow Pine must follow the requirements of 40 CFR 75.24 for out-of-control periods and adjustment for system bias for the fluidized bed boiler monitoring systems. In the event of missing data from the continuous emissions systems, Yellow Pine must follow the requirements of 40 CFR Part 75 Subpart D. Yellow Pine must meet the monitoring plan requirements of 40 CFR 75.53. The provisions of paragraphs (e) and (f) of §75.53 shall be met through December 31, 2008. Yellow Pine must meet the requirements of paragraphs (a), (b), (e), and (f) of §75.53 through December 31, 2008, except as otherwise provided in paragraph (g) of §75.53. On and after January 1, 2009, Yellow Pine must meet the requirements of paragraphs (a), (b), (g), and (h) of §75.53 only. In addition, the provisions in paragraphs (g) and (h) of §75.53 that support a regulatory option provided in another section of 40 CFR Part 75 must be followed if the regulatory option is used prior to January 1, 2009 [40 CFR 75.53(a)]. Yellow Pine must follow the record keeping and reporting requirements of 40 CFR Part 75 Subparts F and G, respectively.

*Part 52.21, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 52.21) Prevention of Significant Deterioration*

Any owner or operator who constructs or operates a source or modification not in accordance with the application submitted pursuant to this section or with the terms of any approval to construct, or any owner or operator of a source or modification subject to this section who commences construction after the effective date of these regulations without applying for and receiving approval hereunder, shall be subject to appropriate enforcement action [40 CFR 52.21(r)(1)]. Upon issuance of its PSD permit, Yellow Pine must commence construction within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time then the permit is invalid [40 CFR 52.21(r)(2)].

Yellow Pine must also develop and implement a written startup, shutdown, and malfunction plan (SSMP) for the auxiliary boiler and fluidized bed boiler that will be available for the Division's review upon request.

To demonstrate compliance with reporting requirements, Yellow Pine must submit a quarterly compliance report which contains, at a minimum, the following information:

- Company name and address.
- Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.
- Date of report and beginning and ending dates of the reporting period.
- The total fuel use by the fluidized bed boiler, for each calendar month within the quarterly reporting period, including, but not limited to, a description of the fuel and the total fuel usage amount with units of measure.
- The total fuel use by the auxiliary boiler, for each calendar month within the quarterly reporting period, including, but not limited to, a description of the fuel and the total fuel usage amount with units of measure.
- A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.
- A signed statement indicating that Yellow Pine burned permitted fuels in applicable equipment.
- The hours of operation for the auxiliary boiler for each calendar month within the quarterly reporting period.
- If a startup, shutdown, or malfunction occurred during the reporting period and the actions taken consistent with Yellow Pine's SSMP.
- If there are no deviations from any emission limits that apply, a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.

The first quarterly report must cover the period beginning on the compliance date and ending on March 31, June 30, September 30, or December 31, whichever date is the first date that occurs at the end of the quarter in which initial startup is completed. The quarterly report must be post marked or delivered no later by the 30$^{th}$ day following the end of each reporting period, April 30, July 30, October 30, and January 30, respectively. Each subsequent report must cover the preparing period from January 1 through March 31, April 1 through June 30, July 1 through September 30, or October 1 through December 31 and must be post marked or delivered no later than April 30, July 30, October 30, and January 30, respectively, which date is the first date following the end of the quarterly reporting period.

*Fluidized Bed Boiler*

Monitoring, record keeping, and reporting as described by 40 CFR Part 60 Subpart Db and 40 CFR Part 75 for applicable pollutants shall be applied as specified, ensuring that monitoring, record keeping, and reporting for both these regulations are satisfied. Yellow Pine is also required to monitor, create records, and submit reports for any emission limit and/or operating limit established under 40 CFR Part 52.21, 40 CFR and Part 63 Subpart B. Any other applicable regulation monitoring, record keeping, and reporting requirements not specifically cited in this section as also required.

To demonstrate compliance with fuel usage limits, Yellow Pine must maintain fuel usage records. These records must track the amount and type of each fuel burned on a daily basis, and must be maintained for a period of five years from the date they were generated. Yellow Pine must also continuously monitor and record the lime injection flow rate for the scrubber system. Yellow Pine must report any instances in which the lime injection rate is less than 80 percent of the tested lime injection rate at which the fluidized bed demonstrated compliance with the HCl limit.

Yellow Pine is also required report any 3-hour block period during which the average opacity the fluidized bed boiler, as measured by the COMS, exceeds the opacity value established during performance testing at which the fluidized bed boiler complies with applicable limits.

Yellow Pine is required to submit the results of all initial and required periodic performance testing and fuel analysis on a quarterly basis for review. Any excess emissions, exceedances, or excursions as described in the permit of the proposed emission limits and/or operating parameter limitations shall be reported during the quarterly reporting period.

Combustion controls monitoring, record keeping, and reporting as previously described shall consist of the following for the fluidized bed boiler:

- Good Combustion Technique: Operator Practices – Maintenance of a written site specific operating procedures manual in which operating procedures, including startup, shutdown, and malfunction are well documented in accordance with the manufacturer’s specifications. The operating procedures must be updated as applicable with any equipment or operating practice changes. The procedures shall contain operating logs documenting such changes and any deviations from the operating procedures. The operating procedures manual shall be maintained in an area allowing easy access to the boiler’s operator and made available for Division review and inspection upon request.

- Good Combustion Technique: Maintenance Knowledge – The boiler must be maintained in accordance with manufacturer’s specifications by personnel with training specific to the boiler and operating procedures.

- Good Combustion Technique: Maintenance Practices – Maintenance of a written site specific procedures manual for best/optimum maintenance practices in accordance to the manufacturer’s specifications for the boiler. Periodic evaluations, inspections, and overhauls as appropriate of the boiler must be conducted in accordance with manufacturer’s specifications. The maintenance practices must be updated as applicable with any equipment or operating practice changes. The modification of these practice changes, scheduled periodic evaluation inspections and overhaul, as appropriate, and any deviations from the prescribed maintenance practices shall be well documented in maintenance logs. The maintenance practices manual shall be maintained in an area allowing easy access to the boiler’s operator and made available for Division review and inspection upon request.

- Good Combustion Technique: Stoichiometic (fuel/air) Ratio – Yellow Pine must continuously monitor and adjust, as applicable, the fuel/air combustion ratio of the fluidized bed boiler per the manufacturer's specifications. Yellow Pine must, at a minimum, install a stack gas oxygen analyzer to continuously monitor excess air and adjust the boiler fuel-to-air ratio for optimum efficiency. In addition, a carbon monoxide trim loop, used in conjunction with the oxygen analyzer is required to assure that incomplete combustion cannot occur due to a deficient air supply. Yellow Pine will be required to operating a CO CEMs, with no exception, at the stack of the fluidized bed boiler. Yellow Pine must submit a request for the Division's review and approval to install continuous fuel/air ratio monitor(s) different than the ones described here. The request must be submitted 30 days prior to proposed installation of the proposed monitor(s). The records resulting from this monitoring shall be maintained on site, unless otherwise required to be submitted to the Division during the quarterly reporting.

- Good Combustion Technique: Fuel Quality Analysis – Yellow Pine will be required to monitor the fuel quality of each of the fuels combusted in the fluidized boiler. Yellow Pine must obtain fuel quality certification from fuel oil, TDF, biomass, and propane suppliers to ensure that the fuel is of an acceptable standard to reduce emissions. These certifications should certify sulfur content, ash content, heating value, and moisture content, as applicable. If such certification cannot be obtained, Yellow Pine must conduct initial and periodic fuel sampling and analysis of the uncertified fuel. Such periodic fuel sampling shall be conducted as fired weekly at a minimum. Such sampling shall include, but is not limited to moisture analysis, ash content, heating value, fuel ash content, and fuel sulfur content. Yellow Pine must develop and maintain fuel-handling practices as specified by the boiler manufacturer to ensure optimum quality necessary to ensure complete combustion, and make them available for review at the Division's request. Such fuel sampling results and/or vender certifications must be submitted for review during the quarterly reporting period.

- Good Combustion Technique: Fuel Sizing – Yellow Pine must develop fuel sizing specifications for applicable fuels (i.e. TDF and biomass) in accordance with manufacturer's specifications to ensure proper combustion efficiency of the fluidized boiler. Yellow Pine shall conduct periodic checks of the fuel sizing in accordance with the boiler's manufacturer, or weekly at a minimum. Yellow Pine shall maintain logs of these checks and make them available for review at the Division's request.

- Good Combustion Technique: Combustion Air Distribution – Yellow Pine must monitor and adjust, when applicable, the air distribution system in accordance with the boiler manufacturer's specifications. Yellow Pine shall maintain logs of such combustion air distribution monitoring and adjusting, and make them available for review at the Division's request.

- Good Combustion Technique: Fuel Dispersion – Yellow Pine must monitor and adjust, when applicable, the fuel in accordance with the boiler manufacturer's specifications. Yellow Pine shall maintain logs of such fuel dispersion monitoring and adjusting, and make them available for review at the Division's request.

Per 40 CFR Part 52.21, all of the required reporting must be submitted on a quarterly basis, subsuming any semiannual or annual reporting established by applicable regulations.

<u>*Auxiliary Boiler*</u>

Monitoring, record keeping, and reporting as described by 40 CFR Part 60 Subpart Dc and 40 CFR Part 63 Subpart B for applicable pollutants shall be applied as specified, ensuring that monitoring, record keeping, and reporting for both these regulations are satisfied. Any other applicable regulation monitoring, record keeping, and reporting requirements not specifically cited in this section as also required.

To demonstrate compliance with operating hours limits, Yellow Pine must maintain operating hours records determined from the required hour meter. These records of the boiler operating hours shall be on a daily basis, and must be maintained for a period of five years from the date they were generated. Yellow Pine must use the operating hours records to calculate monthly operating hours to ensure compliance with applicable calendar year operating hours limits. The monthly operating hours data will be used to calculate the calendar year operating hours. The facility will be required to report the calendar year operating hours from the boilers on a quarterly basis. A report is required when the calendar year operating hours limit is exceeded.

The required quarterly report must contain all items as required for the auxiliary boiler and applicable regulations.

All of the required reporting must be submitted on a quarterly basis, subsuming any semiannual or annual reporting established by applicable regulations.

*Material Storage and Handling [Fuel Process Buildings 1 and 2 (FPB 1 and FPB 2), Tripper Deck Day Silos 1-5 (TDS 1-5), Fuel Storage Silo (SLO), and Fly Ash Silo (AS)]*

Monitoring, record keeping, and reporting as described by 40 CFR Part 60 Subpart OOO for applicable pollutants shall be applied as specified, ensuring that monitoring, record keeping, and reporting for both regulations are satisfied. Yellow Pine is also required to monitor, create records, and submit reports for any emission limit and/or operating limit established under 40 CFR Part 52.21. Any other applicable regulation monitoring, record keeping, and reporting requirements not specifically cited in this section as also required.

The following control technologies must be implored to reduce particulate emissions from the applicable sources:

- Fuel Process Building 1 – Fabric Filter, enclosures, and water sprays.
- Fuel Process Building 2 – Fabric Filter, enclosures, and water sprays.
- Tripper Deck Day Silos 1-5 – Fabric Filter, enclosures, and water sprays.
- Fly Ash Silo – Fabric Filter, enclosure, water sprays, and a closed vent system to the fly ash silo.

Monitoring will consist of records demonstrating that water sprays are applied “as warranted” for adequate dust control. “As warranted” is defined in the permit as dust control sufficient to keep visible emissions below the PSD opacity limit. Weekly observations for any visible emissions will be required as described above. A deviation of the required monitoring as discussed previously above shall be reported as part of the required quarterly report.

The required quarterly report must contain all items as required for applicable equipment and applicable regulations.

Per 40 CFR Part 52.21, all of the required reporting must be submitted on a quarterly basis, subsuming any semiannual or annual reporting established by applicable regulations.

*Material Storage and Handling [Barge/Clamshell Unloading (BCU), Conveyor Transfer Towers 1-3 and 5-8 (CT 1-3 and 5-8), Biomass Storage Pile (BSP), Limestone Storage Pile (LSP), Sand Storage Pile (SSP), Plant Roads (PR), and Fly Ash Trucks (FT)]*

Monitoring, record keeping, and reporting as described by 40 CFR Part 60 Subpart OOO for applicable pollutants shall be applied as specified, ensuring that monitoring, record keeping, and reporting for both regulations are satisfied. Yellow Pine is also required to monitor, create records, and submit reports for any emission limit and/or operating limit established under 40 CFR Part 52.21. Any other applicable regulation monitoring, record keeping, and reporting requirements not specifically cited in this section as also required.

The following control technologies must be implored to reduce particulate emissions from the applicable sources:

Barge/Clamshell Unloading (Limestone, and Sand) – water sprays

Conveyor Transfer Towers 1-3 and 5-8 – enclosures and water sprays

Biomass Storage Pile – water sprays; telescopic chute and water sprays for the storage pile load-in

Limestone Storage Pile – water sprays; telescopic chute and water sprays for the storage pile load-in

Sand Storage Pile – water sprays telescopic chute and water sprays for the storage pile load-in

Fly Ash Trucks – water sprays; use of a vacuum ring on loading/unloading trucks

Monitoring will consist of records demonstrating that water sprays are applied "as warranted" for adequate dust control. "As warranted" is defined in the permit as dust control sufficient to keep visible emissions below the PSD opacity limit. Weekly observations for any visible emissions will be required as described above. A deviation of the required monitoring as discussed previously above shall be reported as part of the required quarterly report.

The required quarterly report must contain all items as required for applicable equipment and applicable regulations.

All of the required reporting must be submitted on a quarterly basis, subsuming any semiannual or annual reporting established by applicable regulations.

*Cooling Tower*

Compliance with the PSD limit shall consists of maintenance of records documenting that the drift eliminator has been designed to meet the applicable limit. Such records shall be submitted for review during the first quarterly report.

*Fuel Storage Tanks*

Yellow Pine is required to monitor, create records, and submit reports for any emission limit and/or operating limit established under 40 CFR Part 52.21. Any other applicable regulation monitoring, record keeping, and reporting requirements not specifically cited in this section as also required.

The following control technologies must be employed to reduce applicable emissions from the applicable sources as described above:

- VOC Emissions – conservation vents and proper operating and maintenance practices as specified by the manufacturer for fuel storage tank

- VOC Emissions – submerged fuel fill pipes on each fuel storage tank

Yellow Pine must monitor the conservation vents and conduct operating and maintenance in accordance with each tank manufacturer's specifications. Yellow Pine shall maintain logs of such monitoring and operation and maintenance, and make them available for review at the Division's request.

# 6.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required to determine the ambient impacts associated with the construction and operation of the proposed modifications. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed modifications, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class I or Class II area. NAAQS exist for $NO_2$, CO, $PM_{2.5,}$, $PM_{10}$, $SO_2$, Ozone ($O_3$), and lead. PSD increments exist for $SO_2$, $NO_2$, and $PM_{10}$.

The proposed project at the Yellow Pine triggers PSD review for CO, $PM_{10}$, $PM_{2.5,}$, $SO_2$, VOCs, and $NO_x$. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for CO, $PM_{10}$, $SO_2$, Pb, and $NO_x$. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application and in the additional information packages.

## Modeling Requirements

The air quality modeling analysis was conducted in accordance with Appendix W of Title 40 of the Code of Federal Regulations (CFR) §51, *Guideline on Air Quality Models*, and Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised).*

The proposed project will cause emission of CO, $PM_{10}$, $SO_2$, $PM_{2.5,}$, VOCs, and $NO_x$ that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment.

**Significance Analysis: Ambient Monitoring Requirements and Source Inventories**

Initially, a Significance Analysis is conducted to determine if the CO, $PM_{10}$, $SO_2$, $PM_{2.5,}$, VOCs, and $NO_x$ emissions at the Yellow Pine would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established monitoring significant level (MSL). The MSL for the pollutants of concern are summarized in Table 6-1.

If a significant impact (i.e., an ambient impact above the MSL) does not result, no further modeling analyses would be conducted for that pollutant for NAAQS or PSD Increment. If a significant impact does result, further refined modeling would be completed to demonstrate that the proposed project would not cause or contribute to a violation of the NAAQS or consume more than the available Class II Increment.

Under current U.S. EPA policies, the maximum impacts due to the emissions increases from a project are also assessed against monitoring *de minimis* levels to determine whether pre-construction monitoring should be considered. These monitoring *de minimis* levels are also listed in Table 6-1. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. This evaluation is required for CO, $PM_{10}$, $SO_2$, Pb, and $NO_x$ .

If any off-site pollutant impacts calculated in the Significance Analysis exceed the MSL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the facility with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses. $PM_{2.5}$ does not yet have established MSLs (3 options proposed on 9/12/07)

**Table 6-1: Summary of Modeling Significance Levels**

| Pollutant | Averaging Period | PSD Significant Impact Level (ug/m$^3$) | PSD Monitoring Deminimis Concentration (ug/m$^3$) |
|---|---|---|---|
| $PM_{10}$ | Annual | 1 | -- |
| | 24-Hour | 5 | 10 |
| $SO_2$ | Annual | 1 | -- |
| | 24-Hour | 5 | 13 |
| | 3-Hour | 25 | -- |
| $NO_X$ | Annual | 1 | 14 |
| CO | 8-Hour | 500 | 575 |
| | 1-Hour | 2000 | -- |

## NAAQS Analysis

The primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of pollutant in the atmosphere, which define the "levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health." Secondary NAAQS define the levels that "protect the public welfare from any known or anticipated adverse effects of a pollutant." The primary and secondary NAAQS are listed in Table 6-2 below.

**Table 6-2: Summary of National Ambient Air Quality Standards**

| Pollutant | Averaging Period | NAAQS | |
|---|---|---|---|
| | | Primary / Secondary (ug/m$^3$) | Primary / Secondary (ppm) |
| $PM_{10}$ | Annual | *Revoked 12/17/06 | *Revoked 12/17/06 |
| | 24-Hour | 150 / 150 | -- |
| $PM_{2.5}$ | Annual | 15 / 15 | -- |
| | 24-Hour | 35 / 35 | -- |
| $SO_2$ | Annual | 80 / None | 0.03 / None |
| | 24-Hour | 365 / None | 0.14 / None |
| | 3-Hour | None/1300 | None / 0.5 |
| $NO_X$ | Annual | 100 / 100 | 0.053 / 0.053 |
| CO | 8-Hour | 10,000 / None | 9 / None |
| | 1-Hour | 40,000 / None | 35 / None |
| Pb | 3-month | 1.5 / None | -- |

If the maximum pollutant impact calculated in the Significance Analysis exceeds the MSL at an off-property receptor, a NAAQS analysis is required. The NAAQS analysis would include the potential emissions from all emission units at the Yellow Pine, except for units that are generally exempt from permitting requirements and are normally operated only in emergency situations. The emissions modeled for this analysis would reflect the results of the BACT analysis for the modified emission unit. Facility emissions would then be combined with the allowable emissions of sources included in the regional source inventory. The resulting impacts, added to appropriate background concentrations, would be assessed against the applicable NAAQS to demonstrate compliance. For an annual average NAAQS analysis, the highest modeled concentration among five consecutive years of meteorological data would be assessed, while the highest second-high impact would be assessed for the short-term averaging periods.

## PSD Increment Analysis

The PSD Increments were established to "prevent deterioration" of air quality in certain areas of the country where air quality was better than the NAAQS. To achieve this goal, U.S. EPA established PSD Increments for certain pollutants. The sum of the PSD Increment concentration and a baseline concentration defines a "reduced" ambient standard, either lower than or equal to the NAAQS that must be met in an attainment area. Significant deterioration is said to have occurred if the change in emissions occurring since the baseline date results in an off-property impact greater than the PSD Increment (i.e., the increased emissions "consume" more that the available PSD Increment).

U.S. EPA has established PSD Increments for $NO_X$, $SO_2$, and $PM_{10}$; no increments have been established for CO or $PM_{2.5}$ (however, $PM_{2.5}$ increments are expected to be added soon). The PSD Increments are further broken into Class I, II, and III Increments. The Yellow Pine is located in a Class II area. The PSD Increments are listed in Table 6-3.

**Table 6-3: Summary of PSD Increments**

| Pollutant | Averaging Period | PSD Increment | |
|---|---|---|---|
| | | Class I ($ug/m^3$) | Class II ($ug/m^3$) |
| $PM_{10}$ | Annual | 4 | 17 |
| | 24-Hour | 8 | 30 |
| $SO_2$ | Annual | 2 | 20 |
| | 24-Hour | 5 | 91 |
| | 3-Hour | 25 | 512 |
| $NO_X$ | Annual | 2.5 | 25 |

To demonstrate compliance with the PSD Increments, the increment-affecting emissions (i.e., all emissions increases or decreases after the appropriate baseline date) from the facility and those sources in the regional inventory would be modeled to demonstrate compliance with the PSD Class II increment for any pollutant greater than the MSL in the Significance Analysis. For an annual average analysis, the highest incremental impact will be used. For a short-term average analysis, the highest second-high impact will be used.

The determination of whether an emissions change at a given source consumes or expands increment is based on the source classification (major or minor) and the time the change occurs in relation to baseline dates. The major source baseline date for $NO_X$ is February 8, 1988, and the major source baseline for $SO_2$ and $PM_{10}$ is January 5, 1976. Emission changes at major sources that occur after the major source baseline dates affect Increment. In contrast, emission changes at minor sources only affect Increment after the minor source baseline date, which is set at the time when the first PSD application is completed in a given area, usually arranged on a county-by-county basis. The minor source baseline dates have been set for $PM_{10}$ and $SO_2$ as January 30, 1980, and for $NO_2$ as April 12, 1991.

## Modeling Methodology

Details on the dispersion model, including meteorological data, source data, and receptors can be found in EPD's PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix D of this Preliminary Determination and in Section 7.0 of the permit application.

A review of the modeling indicated that no physical barrier to public access was delineated on the project site map. Therefore, such a barrier is required to validate the modeling.

## Georgia Toxic Air Pollutant Modeling Analysis

Georgia EPD regulates the emissions of toxic air pollutant (TAP) emissions through a program covered by the provisions of *Georgia Rules for Air Quality Control*, 391-3-1-.02(2)(a)3.(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the Georgia EPD's review of TAP emissions as part of air permit reviews are contained in the agency's "*Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*."

Toxics analysis indicates that silver emissions must be limited to 0.63 pounds per hour to demonstrate compliance with the Toxics Guidelines. Therefore, Yellow Pine will be required to conduct initial performance tests (using EPA Method 29) for Ag emissions from the fluidized bed boiler while operating at maximum load.

Initial performance testing for silver must be conducted within 60 days after achieving the maximum production rate at which the boiler will be operated, but not later than 180 days after the initial startup of the boiler.

During the performance tests for Ag emissions, Yellow Pine must then determine, based on the 6-minute opacity averages, the opacity value corresponding to the 99 percent upper confidence level of a normal distribution of average opacity values at which the fluidized bed boiler complies with applicable limits. Yellow Pine is also required report any 3-hour block period during which the average opacity the fluidized bed boiler, as measured by the COMS, exceeds the opacity value established during performance testing at which the fluidized bed boiler complies with applicable limits.

Yellow Pine must report the results of this test during the quarterly report following the testing.

**Selection of Toxic Air Pollutants for Modeling**

For projects with quantifiable increases in TAP emissions, an air dispersion modeling analysis is generally performed to demonstrate that off-property impacts are less than the established Acceptable Ambient Concentration (AAC) values. The TAP evaluated are restricted to those that may increase due to the proposed project. Thus, the TAP analysis would generally be an assessment of off-property impacts due to facility-wide emissions of any TAP emitted by a facility. To conduct a facility-wide TAP impact evaluation for any pollutant that could conceivably be emitted by the facility is impractical. A literature review would suggest that at least one molecule of hundreds of organic and inorganic chemical compounds could be emitted from the various combustion units. This is understandable given the nature of the diesel fuel, No. 2 fuel, biomass, propane, and TDF fed to the combustion sources, and the fact that there are complex chemical reactions and combustion of fuel taking place in some. The vast majority of compounds potentially emitted however are emitted in only trace amounts that are not reasonably quantifiable.

Appendix E of Application 17700 contain discussion of how toxic emissions were determined. For each TAP identified for further analysis, both the short-term and long-term AAC were calculated following the procedures given in Georgia EPD's *Guideline*. Figure 8-3 of Georgia EPD's *Guideline* contains a flow chart of the process for determining long-term and short-term ambient thresholds. Yellow Pine referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AAC (i.e., 24-hour or 15-minute). The AACs were verified by the EPD.

## Modeling Results

Please refer to the EPD modeling memorandum dated January 23, 2009. This memorandum has been included in Appendix D.

# 7.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit No. 4911-061-0001-P-01-0.

Section 1.0: General Requirements

The following permit conditions were added to standard permit conditions:

Condition 1.6 – General applicability of 40 CFR Part 60, Subpart Db to Source FB.

Condition 1.7 – General applicability of 40 CFR Parts 72, 73, 75, 77 to Source FB.

Condition 1.8 – General applicability of 40 CFR Part 63, Subpart B to Source FB.

Condition 1.9 – General applicability of 40 CFR Part 60, Subpart Dc to Source AB.

Condition 1.10 – General applicability of 40 CFR Part 63, Subpart B to Source AB.

Condition 1.11 – General applicability of 40 CFR Part 60, Subpart IIII to Source EG and FW.

Condition 1.12 – General applicability of 40 CFR Part 63, Subpart ZZZZ to Source EG and FW.

Condition 1.13 – General applicability of 40 CFR Part 60, Subpart Y and 40 CFR Part 60, Subpart OOO to materials handling equipment.

Condition 1.14 – General applicability of 40 CFR Part 68 to Source AT.

Section 2.0: Allowable Emissions

Condition 2.1 defines the requirements to construct and operate the facility in accordance with Georgia Rule 391-3-1-.02(7).

Condition 2.2 requires the commencement of construction of the Yellow Pine facility within 18 months of the issuance of the permit.

Condition 2.3 requires the submittal of a Title V Permit application within 12 months of commencing operation as well as the review of potential applicability of 40 CFR Part 64 to applicable Yellow Pine equipment.

Condition 2.4 defines the Stack FBS.

Condition 2.5 defines the operating loads for Source FB.

Condition 2.6 defines the minimum operating load for Source FB.

Condition 2.7 defines biomass.

Condition 2.8 defines the potential biomass usage in Source FB at applicable operating loads.

Condition 2.9 defines the supplemental fuels and applicable operating loads for Source FB.

Condition 2.10 defines the startup load supplemental fuels for Source FB.

Condition 2.11defines $NO_x$ emissions limits for Source FB.

Condition 2.12 defines filterable $PM_{10}$ emissions limits for Source FB.

Condition 2.13 defines total $PM_{10}$ emissions limits for Source FB.

Condition 2.14 defines $SO_2$ emissions limits for Source FB.

Condition 2.15 defines CO emissions limits for Source FB.

Condition 2.16 defines VOC emission limits for Source FB.

Condition 2.17 defines Pb emission limits for Source FB.

Condition 2.18 defines Hg emission limits for Source FB.

Condition 2.19 defines HCl emission limits for Source FB.

Condition 2.20 defines fluidized bed type for Source FB.

Condition 2.21 defines allowable specifications for TDF.

Condition 2.22 defines the fuels that can be fired in Source AB.

Condition 2.23 defines operating hours limitations for Source AB.

Condition 2.24 defines PM and opacity emissions limits for Source AB.

Condition 2.25 defines opacity limits for Equipment Group NMH.

Condition 2.26 defines opacity limits for Equipment Group FMH.

Condition 2.27 defines effectiveness of drift eliminators on the CT.

Condition 2.28 defines the fuels that can be fired in Sources EG and FW.

Condition 2.29 defines allowable sulfur contents of applicable fuels.

Condition 2.30 defines opacity limit for Source FB.

Condition 2.31 defines $PM_{10}$ emissions limits for applicable materials handling equipment.

Condition 2.32 defines a 12-consecutive month period.

Condition 2.33 defines an operating day.

Condition 2.34 defines silver emissions limit for Source FB.

Condition 2.35 requires installation of a physical barrier around the site.

Section 3.0: Fugitive Emissions

No specific conditions in Section 3.0 are being added as part of this permit action.

Section 4.0: Requirements for Control Equipment

Condition 4.1 requires the installation of SNCR 1 on Stack FBS.

Condition 4.2 requires the installation of BH1 on Stack FBS.

Condition 4.3 requires the installation of DS1 on Stack FBS.

Condition 4.4 requires the installation of low $NO_x$ burners on Source AB.

Condition 4.5 requires the installation of particulate matter control equipment on applicable non-fugitive materials handling equipment.

Condition 4.6 requires the installation of particulate matter control equipment on applicable fugitive materials handling equipment.

Condition 4.7 requires the installation of drift eliminators on Source CT.

Condition 4.8 requires the installation of conservation vents and submerged fill pipes on the fuel storage tanks.

Section 5.0: Monitoring

Condition 5.1 explains general requirements for the operation of a continuous monitoring system.

Condition 5.2 requires the installation of BACT required CEMS in Stack FBS.

Condition 5.3 requires the a continuous operating hours meter for Source AB, a continuous temperature indicator for Source FB, a continuous means of determining the operating loads of Source FB, and a continuous means for determine the lime injection flow rate into DS1 for Source FB.

Condition 5.4 requires the monitoring of fuel usage from Source FB.

Condition 5.5 defines good combustion controls for Source FB.

Conditions 5.6 and 5.7 define the monitoring applicable to applicable materials handling equipment, the emergency generator and fire water pump, respectively.

Section 6.0: Performance Testing

Condition 6.1 lists the applicable testing method for applicable equipment.

Condition 6.2 discusses the requirements for applicable CEMS.

Condition 6.3 requires measuring of opacity during $PM_{10}$, Hg, Ag, and Pb performance testing to establish an opacity value that will demonstrate compliance with applicable limits.

Conditions 6.4 through 6.6, and 6.8 define the required performance testing and associated requirements for Source FB.

Condition 6.7 defines general testing requirements.

Section 7.0: Notification, Reporting and Record Keeping

Condition 7.1 defines the records maintenance schedule.

Condition 7.2 requires record keeping of the operating hours for Source AB.

Condition 7.3 requires submittal of control equipment operation plan in relationship to Source FB.

Conditions 7.4 and 7.5 require submittal of applicable records for material handling equipment.

Condition 7.6 discusses required startup/shutdown plans and compliance reports for Sources AB and FB.

Conditions 7.7, 7.9 through 7.12, 7.16, and 7.17 discuss record keeping and reporting associated with compliance demonstration for applicable limits for Source FB.

Condition 7.8 discusses record keeping requirements for the cooling tower CT.

Condition 7.13 defines the timeline for which are records shall be kept.

Condition 7.14 requires reporting of any deviations and corrective actions taken.

Condition 7.15 requires reporting of excess emissions, exceedances and excursions associated with this permit.

Condition 7.18 defines excess emissions, exceedances and excursions associated with this permit.

Section 8.0: Special Conditions

Condition 8.2 requires facility to pay an annual permit fee once the plant becomes operational.

Condition 8.3 defines excess emissions.

# APPENDIX A – 112(g) Case-By-Case Maximum Achievable Control Technology Determination

**112(g) Case-By-Case Maximum Achievable Control Technology Determination**
**Review of Yellow Pine Energy Company, LLC**
**Construction/Operation of a Biomass-Fired Power Plant**
**Located in Fort Gaines, Georgia (Clay County)**

# NOTICE OF MACT APPROVAL

SIP Permit Application No. 17700
February 2009

**Reviewing Authority**

**State of Georgia**
**Department of Natural Resources**
**Environmental Protection Division**
**Air Protection Branch**
**Stationary Source Permitting Program (SSPP)**

**Prepared and Reviewed By:**

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# 1.0 EXECUTIVE SUMMARY

Yellow Pine Energy Company, LLC (Yellow Pine) submitted an application for a permit to construct and operate a 110-megawatt (MW) biomass-fired power plant. The proposed project will include: fluidized bed boiler(s) with a total heat input capacity of 1,529 million British Thermal Units per hour ($10^6$ Btu/hr); a condensing steam turbine generator; an auxiliary boiler with a heat input capacity of 25 x $10^6$ Btu/hr; multi-cell mechanical draft wet cooling tower; a water treatment plant; a wastewater treatment plant and outfall; a back-up emergency diesel generator and diesel firewater pump; ash/inert landfill; aqueous ammonia storage tank; limestone storage bins; a No. 2 fuel oil storage tank; diesel fuel oil storage tanks; and supporting plant equipment. In the original application, the plant would have the capability of firing bituminous coal, petroleum coke (pet coke), or 95% metal-free tire-derived fuel (TDF) in small quantities in addition to biomass fuel. However, subsequent Yellow Pine submittals to EPD indicate that the plant will now have the capability of firing only 95% metal-free tire-derived fuel (TDF) in small quantities in addition to biomass fuel. In addition, the original application indicated the possibility of installing one or two fluidized bed boilers to obtain the required heat input capacity. Based on recently submitted additional information (August 1, 2008 Yellow Pine Submittal to EPD), Yellow Pine proposes to install one bubbling fluidized bed (BFB) boiler to obtain the heat input capacity needed to run the plant. Low sulfur No. 2 fuel oil or propane is proposed for use at start-up of the fluidized bed boiler and as the primary fuel of the auxiliary boiler.

Yellow Pine is to be located at Georgia Highway 39 in Fort Gaines, Georgia in Clay County. Clay County is classified as “attainment” or “unclassifiable” for all criteria pollutants.

Under 40 CFR 63 Subpart A, Yellow Pine will be a major source of HAP emissions because, even with permit limits, it will have the potential to emit more than 10 tons per year of any individual HAP or 25 tons per year of any combination of HAPs. As a newly constructed major source of HAPs without a promulgated Part 63 National Emission Standard for Hazardous Air Pollutants (NESHAP), this facility is subject to a case-by-case Maximum Achievable Control Technology (MACT) determination pursuant to Section 112(g) of the Clean Air Act Amendments of 1990.

Yellow Pine’s proposed boilers are part of an industry category for Industrial, Commercial and Institutional Boilers and Process Heaters, for which the U.S. EPA promulgated a MACT standard called 40 CFR Part 63, Subpart DDDDD, “National Emission Standards for Hazardous Air Pollutants: Industrial, Commercial and Institutional Boilers and Process Heaters” (Boiler MACT) which was published in the Federal Register on September 13, 2004. This rule was vacated by the District of Columbia (D.C.) Circuit Court of Appeals on June 18, 2007; that decision became final by court mandate on July 30, 2007. Because a new NESHAP for this source category has not been promulgated at the time of permit issuance, the Yellow Pine boilers are subject to the case-by-case MACT-level control technology review under Section 112(g) of the 1990 Clean Air Act Amendments. The requirements for such case-by-case control technology reviews are codified in 40 CFR Part 63, Subpart B and adopted by reference, with a few revisions and clarifications, into the Georgia Rules for Air Quality Control.

To satisfy the 112(g) case-by-case MACT requirements (40 CFR 63.40 through 63.44, Control Technology Requirements in Accordance with Section 112(g)(2)(B) of the 1990 Clean Air Act Amendments), Yellow Pine submitted applications for a MACT determination specifying control technology that, if properly operated and maintained, will meet the MACT emission limitations or standards determined according to the principles set forth in 40 CFR 63.43(d). Their analysis of similar facilities indicates that case-by-case MACT should be based on the emissions limitations and work practice standards of the vacated MACT standard. In order to fulfill these requirements, Yellow Pine has requested emission limits for particulate matter, HAP, and carbon monoxide. Specifically the HAPs are split into categories which consists of HCl, Metal HAPs (Total selected metals (TSM) and mercury), and Organic HAPs (CO is the surrogate pollutant or organic HAPs). Yellow Pine proposes to comply with the above-mentioned emission limits and the emission standards by utilizing a dry scrubber, Selective Non-Catalytic Reduction (SNCR) system, and a baghouse.

Yellow Pine will be subject to the Title V operating permit program because actual and potential emissions of NOx, CO, VOC, and HAPs will exceed the major source thresholds. Yellow Pine must submit an application for a Title V permit within 12 months of commencing operations at the Fort Gaines facility.

# 2.0 APPLICATION INFORMATION

The permit application includes: an air quality permit application with process descriptions and an emissions inventory and 112(g) requirements. A toxic impact assessment was performed and included with the application. The toxic emissions impact from the construction and operation of the proposed facility is expected to be insignificant.

## 2.1 Applicant Name and Address

Yellow Pine Energy Company, LLC c/o Summit Energy Partners, LLC
Yellow Pine Energy Company, LLC
Georgia Highway 39
Fort Gaines, Georgia 39857
Clay County

## 2.2 Authorized Representative

Mark S. Sajer
Managing Director

## 2.3 Application Submittals

| | |
|---|---|
| September 27, 2007 | Date of initial SIP application assigned Application No. 17700 |
| November 30, 2007 | Case-by-case MACT determination application for Auxiliary Boiler |
| August 1, 2008 | Case by-case MACT determination application for Fluidized Bed Boiler |

# 3.0 BACKGROUND

The permit application and subsequent submittals include: an air quality permit application with process descriptions and an emissions inventory and elements of the 112(g) case-by-case MACT determination. A toxic impact assessment was performed and included with the application. The toxic emissions impact from the construction and operation of the proposed facility is expected to be insignificant.

## 3.1 Facility Location

Yellow Pine Energy Company, LLC (Yellow Pine) submitted Application No. 17700 dated September 27, 2007 to construct and operate a 110 MW power generation facility in Fort Gaines, Georgia. The facility would consist of a 1,529 million British Thermal Units per hour ($10^6$ Btu/hr) bubbling, fluidized-bed (BFB) boiler fueled by biomass. The plant will have the capability of firing 95% metal-free tire-derived fuel (TDF) in small quantities in addition to biomass fuel. Low sulfur No. 2 fuel oil or propane will be used for start-up of the fluidized bed boiler and will be the primary fuel of the auxiliary boiler.

## 3.2 Permit Status of Facility Operations

As a new facility, the proposed Yellow Pine does not have any pre-existing air quality permits. The facility intended to begin construction in April of 2008. The company will be required to submit a complete Title V application within twelve (12) months after the date that production operations commence at the Fort Gaines facility.

## 3.3 Project Schedule

Construction on the proposed plant was expected to be completed in 2010, and regular production operations were scheduled to commence in 2010.

## 3.4 Proposed Operation

Yellow Pine intends to construct and operate a biomass-fired power plant facility. The primary emission source at the facility will be a 1,529 x $10^6$ Btu/hr bubbling, fluidized-bed (BFB) boiler fueled by biomass. The plant will have the capability of firing 95% metal-free tire-derived fuel (TDF) in small quantities in addition to biomass fuel. Low sulfur No. 2 fuel oil or propane will be used for start-up of the fluidized bed boiler and will be the primary fuel of the auxiliary boiler. Steam from the BFB boiler will be routed to a turbine generator that will provide electricity for distribution to the power grid. The auxiliary boiler has a heat input capacity of 25 x $10^6$ Btu/hr, and will be used to provide auxiliary steam for the fluidized boiler. According to Application 17700, aside from maintenance testing of the auxiliary boiler, it will only be used during facility startup activities.

Yellow Pine will have a small emergency generator, 1,500 KW, which will be used to keep the control room and certain essential equipment energized, awaiting a restart. In Appendix C of a letter date April 16, 2008 from CH2M Hill acting on behalf of Yellow Pine, the displacement of the proposed engine will be 50.3 liters. The facility will also have an emergency diesel firewater pump. During normal operation, the power supply from the facility or the transmission line (back-up) would run the firewater system. The 450 horsepower (Hp) fire pump engine will have a displacement of 14.6 liters, according to Appendix D of a letter date April 16, 2008 from CH2M Hill acting on behalf of Yellow Pine. Emissions of criteria pollutants and hazardous air pollutants (HAPs) will result from the combustion of these fuels in the boilers and the engines. The plant is expected to be utilized over an annual basis of 100%. This equates to operating 8,760 hours per year. The potential emissions are based on this utilization.

## 4.0 EMISSION RATES AND CHANGES

The methodologies used to quantify emissions from the emissions units at the Yellow Pine facility are summarized in Application 17700. The emission rates are calculated for all of the operations of the proposed facility. Projected emission rates are estimated by multiplying an emission factor by an associated process rate.

### 4.1 Case-by-Case MACT Applicability Under Section 112(g) of the 1990 CAAA

A newly constructed or reconstructed major source of HAP without a promulgated Part 63 NESHAP will be subject to the requirements 40 CFR 63.40 through 63.44, including a case-by-case MACT determination as described by the Section 112(g) of the 1990 Clean Air Act Amendments. The proposed Yellow Pine facility is a “construction of a major source” as defined by 40 CFR 63.41. The facility will not be a reconstruction or modification of an existing site, and it will be a major source of HAPs because it will have the potential to emit more than 10 tons per year of any individual HAP or 25 tons per year of any combination of HAPs.

### 4.2 HAP Emissions Profile

The fluidized bed boiler, auxiliary boiler, emergency generator, and firewater pump are the sources of HAP emissions. Appendix E of Application 17700 contains tables with a speciation of the HAP emissions from the boilers. According to Application 17700, total potential HAP emissions are 231 tons per year, based on the combustion of biomass in the fluidized bed boiler.

## 5.0 MAXIMUM AVAILABLE CONTROL TECHNOLOGY (MACT) ANALYSIS

A 112(g) case-by-case MACT determination is required for this facility. MACT emission limitation for new sources is defined as:

> "…the emission limitation which is not less stringent that the emission limitation achieved in practice by the best controlled similar source, and which reflects the maximum degree of deduction in emissions that the permitting authority, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable by the constructed or reconstructed major source."
> [40 CFR 63.41]

The requirements of the determination are set forth in 40 CFR 63.40 through 63.44.

### 5.1 MACT Technical Approach

Because EPA could not immediately issue MACT standards for all industries (and there was a potential for significant new sources of toxic air emissions to remain uncontrolled), section 112(g) of the Clean Air Act acts as a "gap-filler" requiring MACT-level control of air toxics when a new major source of HAP is constructed or reconstructed. The facility provides basic information about the source and its potential emissions through its air quality permit application. The application also specifies the emission controls that will ensure that new source MACT will be met. The Division reviews and approves (or disapproves) the application, and provides an opportunity for public comment on the determination.

The principles of a 112(g) case-by-case MACT determination are outlined in 40 CFR 63.43(d)(1) through (4) as follows:

> (d) *Principles of MACT determinations.* The following general principles shall govern preparation by the owner or operator of each permit application or other application requiring a case-by-case MACT determination concerning construction or reconstruction of a major source, and all subsequent review of and actions taken concerning such an application by the permitting authority:
>
> (1) The MACT emission limitation or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source, as determined by the permitting authority.
>
> (2) Based upon available information, as defined in this subpart, the MACT emission limitation and control technology (including any requirements under paragraph (d)(3) of this section) recommended by the applicant and approved by the permitting authority shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.

(3) The applicant may recommend a specific design, equipment, work practice, or operational standard, or a combination thereof, and the permitting authority may approve such a standard if the permitting authority specifically determines that it is not feasible to prescribe or enforce an emission limitation under the criteria set forth in section 112(h)(2) of the Act.

(4) If the Administrator has either proposed a relevant emission standard pursuant to section 112(d) or section 112(h) of the Act or adopted a presumptive MACT determination for the source category which includes the constructed or reconstructed major source, then the MACT requirements applied to the constructed or reconstructed major source shall have considered those MACT emission limitations and requirements of the proposed standard or presumptive MACT determination.

### 5.2 Potential Control Options Review

The operations at the proposed Yellow Pine facility were evaluated for potential applicability under NESHAPs that have already been promulgated. Emissions of HAPs from the proposed emergency generator and firewater pump are regulated by *Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 63) National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [RICE].* No currently promulgated NESHAP under 40 CFR Part 63 will be applicable to the proposed BFB or auxiliary boiler.

The BFB boiler and auxiliary boiler were evaluated to determine the appropriate MACT level controls under Section 112(g) of the 1990 Clean Air Act Amendments. This evaluation included a review of any proposed NESHAPs under Section 112(d) that have not yet been promulgated and an evaluation of the best-controlled similar sources in the industry located elsewhere in the United States and its territories.

As stated in the *National Associate of Clean Air Agencies' (NACAA's) Reducing Hazardous Air Pollutants from Industrial Boilers: Model Permit Guidance* (June 2008), EPA has determined that CO emissions can serve as a reasonable surrogate for control of the organic HAPs, HCl may serve as a reasonable surrogate for control of inorganic (acid gas) HAPs, and that PM may serve as a reasonable surrogate for a number of non-volatile metal HAPs. Therefore, the Division will follow this determination when performing its evaluations of potential control technologies in its Case-by-Case MACT determination for the proposed boilers.

### 5.3 Technical Feasibility Review

A control method or technology is considered available if it can be obtained through commercial channels or applied within the common sense meaning of the term. An available control technology is applicable if it can reasonably be installed and operated. A technology that is both available and applicable is technically feasible. EPA has identified the potential control options in the proposed MACT standard as being available and applicable.

## 5.4 Company's Proposed MACT for HAP Control

### 5.4.1 Bubbling Fluidized Bed Boiler

The fluidized bed boiler's mercury emissions, a hazardous air pollutant, were originally regulated under Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart HHHH—Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units, which has since been vacated. The Division requested submittal of a Case-by-Case MACT application for the proposed fluidized bed boiler in a letter dated June 17, 2008. Yellow Pine submitted the requested Case-by-Case MACT application as Appendix B of its August 1, 2008 response to the Division's June 17, 2008 letter.

Per the application, Yellow Pine undertook a survey of similar fluidized bed, biomass-fired or biomass-supplemental co-fired plants and performed additional evaluation. The biomass-fired FB units studied are Plainfield Renewable Energy, and Plant Carl. There are coal with biomass co-firing CFB units in operation (ADM) and proposed (Dominion – Virginia City, Wellington Development – Green Energy Resource Recovery Project). The following table attempts to summarize Yellow Pine's findings as included in the permit application.

| Facility/Location | Boiler Type/Description | Fuel Type/Description | Pollutant | Emission Rate | Proposed MACT | Control Efficiency |
|---|---|---|---|---|---|---|
| Plainfield Renewable Energy | Circulating Fluidized Bed Boiler | Not provided in application | Mercury | 3.0 E-6 lb Hg/MMBTU | Not provided in application | Not provided in application |
| | | | HCl | 0.00436 lb HCl/MMBTU | Not provided in application | Not provided in application |
| Public Service of New Hampshire's Plant Schiller | 50 MW Circulating Fluidized Bed Boiler | Biomass and coal fired | Mercury | 3 E-06 lbs/MMBTU based on 6 lb Hg/TBTU fuel input | good combustion controls, and fabric filter | 50 percent |
| | | | HCl | 0.02 lb/MMBTU. | limestone injection into the bed SNCR | Not provided in application |
| Plant Carl | Bubbling Fluidized Bed Boiler | | CO as the surrogate for organic HAPs | 0.149 lb/MMBTU | good combustion controls and oxidation catalyst | Not provided in application |
| | | | PM is the surrogate for TSM/Hg with a | PM limit of 0.025 lb/MMBTU and TSM sublimit of 0.0003 lb/MMBTU | good combustion controls and ESP | Not provided in application |
| | | | HCl | 0.02 lb/MMBTU | good combustion practices and the scrubber | 92 percent |

| Facility/Location | Boiler Type/Description | Fuel Type/Description | Pollutant | Emission Rate | Proposed MACT | Control Efficiency |
|---|---|---|---|---|---|---|
| | | | mercury | 0.000003 lb Hg/MMBTU | good combustion controls and ESP | 50 percent |
| ADM | Circulating Fluidized Bed Boiler | Coal and biomass and up to 20% biomass, PetCoke and TDF. | Not provided in application | Not provided in application | limestone, SNCR and fabric filter, but no scrubber | Not provided in application |
| Green Energy Resource Recovery Project | Circulating Fluidized Bed Boiler | fire waste coal and 15% bituminous coal. | mercury | 1.1 E-6 lb Hg/MWHr for waste coal and 6.0 lb Hg/MWHr, and based on an 85/15 mix; the result is 1.835 E-6 lb Hg/MWHr based on a maximum Hg content of 0.26 ppm and 90% control efficiency from the fabric filter | Not provided in application | Not provided in application |
| Old Dominion | Two Circulating Fluidized Bed Boilers each rated at 334 MW | waste coal, coal and biomass. | mercury | Not provided in application | Not provided in application | 98 percent |

Per the application, potential control strategies and technologies were evaluated for the following HAP subcategories:

- Inorganic HAPs, including acid gases (HCl) – wet or dry scrubbers
- Metal HAPs (TSM) – particulate control devices – fabric filter or ESP and waste wood wood specifications prohibiting pesticide/rot/creosote/arsenated copper chromate less than 1% by weight of the total fuel input to the Fluidized Bed Boiler(s)
- Mercury (Hg) – combination of scrubber, particulate control (fabric filter), an evaluation of ACI, bag house/stack exit temperature monitoring
- Organic HAP – good combustion controls and CO monitoring.

Yellow Pine's application indicates that an oxidation catalyst for Organic HAPs was not included due to its investigation showing that such technology is not technically feasible. According to the application, the proposed controls reduce total HAPs from 1,478 tons/year to 231 tons/year.

For Inorganic HAPs (acid gases), Yellow Pine selected good combustion controls and dry scrubber, with 90% control efficiency, monitored by stack testing for MACT.

Yellow Pine indicated an operating procedure regarding wood waste to exclude certain contaminants is viable. Therefore, it is feasible to limit wood contaminants to less than 1% by weight per year. For TSM, co-controls of a scrubber-fabric filter at a 90% control efficiency, with compliance via PM monitoring as a surrogate and stack testing to initially correlate fuel input to stack testing and temperature control, are selected for MACT.

According to Yellow Pine's application, the operating procedure regarding exit gas temperature monitoring is viable, and acts as a surrogate for CEMS for mercury. Yellow Pine's BACT analysis shows very low mercury emissions due to the fuel specifications of low mercury content and co-controls achieving 90% mercury reduction. Yellow Pine's very low concentrations of mercury result in very high removal costs using ACI. Yellow Pine further discussed an adverse environmental impact of using ACI is more coal firing to produce ACI and related emissions. R&D papers indicate that perhaps amended silicates will be developed to replace ACI, but at present, this idea is still in research, and therefore, not a MACT alternative (not technically feasible). Yellow Pine proposes initial stack testing to correlate fuel mercury content to emissions and stack exit temperature monitoring are a viable means to enhance mercury emission co-control.

For Organic HAPs, good combustion controls, with compliance by CO emissions and CO CEMS monitoring is selected by Yellow Pine for MACT.

The Case-by-Case MACT for HAP analysis was summarized in the application as presented in the table below along with Yellow Pine's proposed BACT limits. The table is presented verbatim as included in the application.

| AP Category | Uncontrolled Emissions (tpy) | Controlled Emissions (tpy) | Proposed BACT / PSD Application | MACT Assessment | Control and Compliance Determination Method |
|---|---|---|---|---|---|
| Mercury | | | | | Co-firing with biomass, SNCR, dry scrubber, fabric filter / Stack & temperature testing |
| 100% Biomass<br><br><br>lb/MMBTU (total)<br>0.025 lb/MMBTU<br>As above | .0234 tpy .0000035 lb/MMBTU | | .0023 tpy, .00000035 lb/MMBTU | 0.000003 lb/MMBTU | As above |
| 85/15 Bio/Coal | .0239 tpy .00000357 lb/MMBUT | | .0024 tpy, .00000036 lb/MMBTU | 0.000003 lb/MMBTU | As above |
| 85/15 Bio/PetCoke | .0644 tpy .00000962 lb/MMBTU | .0064 tpy | .0064 tpy, .000000096 lb/MMBTU | 0.000003 lb/MMBTU | As above |
| 85/15 Bio/TDF | .0206 tpy .00000308 lb/MMBTU | | .0021 tpy, .00000031 lb/MMBTU | 0.000003 lb/MMBTU | As above |

| AP Category | Uncontrolled Emissions (tpy) | Controlled Emissions (tpy) | Proposed BACT / PSD Application | MACT Assessment | Control and Compliance Determination Method |
|---|---|---|---|---|---|
| Non-Mercury Total Selected Metals – as PM | 115 tpy | 11.5 tpy | 0.015 lb/MMBTU (filterable) 0.030 lb/MMBTU (total) | 0.025 lb/MMBTU | As above |
| Organic HAPs – as CO | 91.8 tpy | 91.8 tpy | 0.149 lb CO/MMBTU | 0.149 lb/MMBTU | Good combustion controls, wood waste quality control / CO CEMS |
| Acid Gases – HCL | 1,272 tpy | 127.2 tpy | n/a | 0.019 lb/MMBTU | Dry scrubber / Stack Testing |
| Total | 1,478 tpy | 231 tpy | | | |

### 5.4.2 Auxiliary Boiler

The proposed auxiliary boiler would have been subject to *Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 63) National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart DDDDD- Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters*. However, this regulation was vacated by the District of Columbia (D.C.) Circuit Court of Appeals on June 18, 2007. The Division has determined that the emission rates, operating limits, and work practice standards of the vacated MACT standard meet the criteria to be a 112(g) case-by-case MACT determination. As a result, the Division requested that Yellow Pine submit a Case-by-Case MACT determination application in accordance with § 63.53. Yellow Pine submitted a case-by-case MACT determination application as Appendix A of its November 30, 2007 letter to the Division.

Yellow Pine proposes to limit operating hours of the auxiliary boiler to 250 hours per calendar year. The pollutants requiring review are:

- Non- Mercury Metals (arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium)
- Mercury
- Acid Gases (hydrogen chloride and hydrogen fluoride)
- Organic Hazardous Air Pollutants [HAPs] (formaldehyde, naphthalene, 1,1,1-trichloroethane, toluene, o-xylene, polycyclic organic matter)

Under the vacated MACT standard, a limited use liquid fuel boiler is any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 x $10^6$ Btu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent. Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year, and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

The potential annual heat input capacity of the auxiliary boiler is 219,000 x $10^6$ Btu. Based on a No. 2 fuel oil heat capacity of 139,600 Btu/gallon, a potential hour fuel usage of approximately 179 gallons/year, and the operating hour limit of 250 hours/year, the actual annual heat input capacity of the auxiliary boiler is 6,250 x $10^6$ Btu. Therefore, the annual average capacity factor for fuel oil is approximately three percent. Therefore, the proposed auxiliary boiler will be regulated as a limited use liquid fuel boiler.

*Metals*

According to the case-by-case MACT application, metals will be a subset of particulate matter emitted from the auxiliary boiler, and it is reasonable to use a particulate matter emission limit as a surrogate for the MACT standard for individual metal HAPs. Therefore, Yellow Pine proposed using PM as a surrogate pollutant as MACT for metals emitted from the auxiliary boiler. Yellow Pine Energy also proposed the use of low ash fuels and good combustion practices as MACT for metals. Yellow Pine proposes compliance verification with the metal MACT standard with the PM limit of 0.03 lb/ $10^6$ Btu and through opacity readings. The PM emission limit proposed is equal to the PM limit in the recently vacated Boiler MACT for new limited use liquid fuel-fired units.

*Acid Gases*

According to the case-by-case MACT application, Yellow Pine Energy proposed that compliance with the proposed HCl emission limit of 0.0009 lb/$10^6$ Btu by analyzing fuel oil for heat content and chlorine concentration and converting the concentration into units of lb/MMBtu. The HCl emission limit proposed is equal to the HCl limit in the recently vacated Boiler MACT for new limited use liquid fuel-fired units.

Hydrogen fluoride emissions were not addressed by case-by-case MACT application. Although, Yellow Pine does not propose case-by-case MACT for these emissions, fluorides which are also regulated under 40 CFR 52.21 are expected to be minimum due to the proposed fuels and operation hours of the auxiliary boiler. Hydrogen sulfide emissions, also regulated under 40 CFR Part 52.21, are also expected to be almost negligible for this reason.

*Organic HAPs*

According to the case-by-case MACT application, it is reasonable to use CO emissions as a surrogate for the MACT standard for organic HAP emissions. The recently vacated Boiler MACT stated that CO monitoring is considered to be adequate for demonstrating compliance with MACT for new limited use liquid fuel-fired units. Therefore, Yellow Pine Energy proposed compliance with the CO BACT limit as a demonstration of compliance with MACT for organic HAP emissions. Carbon monoxide emissions are regulated under 40 CFR 52.21.

## 5.5 Preliminary MACT Determination

### 5.5.1 Bubbling Fluidized Bed Boiler

Since the submittal of Yellow Pine's August 1, 2008 Case-by-Case MACT application, Yellow Pine has withdrawn its original request to burn bituminous coal and/or petroleum coke (Pet. Coke) at the facility. The Division has reviewed the permit application and has the following issues with Yellow Pine's proposals.

- The proposed Plainfield Project, to be located in Plainfield, Connecticut is listed as a permit reviewed in the Yellow Pine Case-by-Case MACT application. No documentation (which could be considered as supporting documentation) other than the mention of the project and a brief discussion of it is provided. The 37-megawatt wood-fueled power production technology is an advanced, staged *gasification* system that generates steam used to drive a conventional steam turbine generator.

  A review of the proposed permit indicates that the power plant will use a fluidized bed staged gasification process with a close-coupled boiler to power the steam turbine generator. The biomass fuel will come from various sources which includes forest management residues, land clearing debris, waste wood from industries, construction and demolition (C&D) waste, allowed as a renewable energy project by Connecticut. During startup bio-diesel (B100) is used to supplement the solid fuel supply.

  Page 6 of the proposed permit indicates that initially the proposed project was a major source of benzene and hydrogen chloride. However, after a subsequent emissions estimate submittal, the project was not considered a major source of HAPs. The permit has requirements for the source to perform stack testing for all likely HAPs to ensure they are not emitted above the major source thresholds. Furthermore, the Plainfield Project is a HAP synthetic minor source as it is limited to not emit more than 10 tons of any individual HAP or 25 tons of any combination of HAP, on an annual basis, listed in Section 112(b) of the Clean Air Act Amendments of 1990. The limits for Hg and HCl listed in Yellow Pine's Case-by-Case MACT application in relationship to Plainfield are BACT limits under 40 CFR 52.21 and Section 112 avoidance limits, respectively, and are not MACT limits under 40 CFR Part 63 Subpart B.

  Based on a preliminary review of the proposed draft Plainfield permit and data provided in Yellow Pine's Case-by-Case MACT application, it is not justified to use the Plainfield project as an acceptable source for establishing the MACT floor for Yellow Pine's bubbling bed boiler.

- The Public Service of New Hampshire's Plant Schiller permit, written in 2006, is listed a permit reviewed in relationship of establishing the MACT floor in the Yellow Pine Case-by-Case MACT application.

  Public Service of New Hampshire's Plant Schiller (PSNH) involved the construction and operation of a nominal 50 MW wood-fired boiler. Air pollution control at the facility included a selective non-catalytic reduction (SNCR) system for nitrogen oxides ($NO_x$), a limestone injection system to control sulfur dioxide ($SO_2$) and acid gases, and a fabric filter for the control of particulate matter. PSNH was also to operate continuous emission monitors (CEMs) to continuously record $SO_2$, CO, $NO_x$, opacity and certain operational parameters. The statement of basis for the Plant Schiller permit was written in 2004 and cites the then proposed Utility MACT and Boiler MACT.

  Both of which have been since vacated (Utility MACT in the form of CAMR). The Yellow Pine application cites that mercury control was proposed at 50 percent, and suggests no mercury CEMs. However, recent CAMR requirements, although vacated, would have required a mercury monitoring system. Therefore a mercury CEMs would be in line with recent regulations and available technology. No supporting information was provided in Yellow Pine's Application.

- The Green Energy Partners, LLC Plant Carl's Case-by-Case permit, a permit reviewed in relationship of establishing the MACT floor in the Yellow Pine Case-by-Case MACT application, requires the installation of an oxidation catalyst. The Yellow Pine Case-by-Case application mentions that its investigations into the installation of an oxidation catalyst is technically infeasible. However, no technical information to support that finding is included in the permit application. Furthermore, additional information provided in relationship to the PSD application discussion of an oxidation catalyst does not provide any technical information background information other than an email from one potential oxidation catalyst manufacturer. Additional justification is believed necessary to truly eliminate a CO oxidation catalyst as a technically feasible Case-by-Case MACT alternative. No supporting information was provided in Yellow Pine's Application.

  In a letter dated November 12, 2008, the Division requested that Yellow Pine continue to review the technical feasibility and cost effectiveness of an oxidation catalyst to control CO emissions.

- ADM Columbus' permit is mentioned as a permit reviewed for Yellow Pine's Case-by-Case Permit Application. Yellow Pine's application lists the proposed MACTs established by ADM Columbus' application, but no other information or data is given. No supporting information was provided in Yellow Pine's Application. It is important to note that ADM's permit, like Plant Schiller's, was written before the promulgation of the now vacated CAMR Rule. Therefore, the absence of a mercury limit is believed to be a moot point.

- The Wellington Development – Green Energy Resource Recovery Project was reviewed as part of Yellow Pine's Case-by-Case application. A review of the proposed permit does not indicate MACT review.

- Dominion Resources' draft Case-by-Case permit was reviewed as part of Yellow Pine's Case-by-Case Application. Yellow Pine's application mentions cost analysis in relationship to mercury control. However no documentation is provided as part of Yellow Pine's application.

- The Case-by-Case MACT application indicates that uncontrolled and controlled emissions are the same for all pollutants except HCl. In a letter dated November 12, 2008, the Division questioned the validity of Yellow Pine's controlled HCl emissions rate as it equates to the uncontrolled HCl emissions rate as provided in *AP 42, Fifth Edition* Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources *Table 1.6-3. Emission Factors for Speciated Organic Compounds, TOC, VOC, Nitrous Oxide, and Carbon Dioxide from Wood Residue Combustion*. No emission estimates or examples of such are not provided.

*Non- Mercury Metals*

As previously discussed, particulate matter can serve as a reasonable surrogate for a number of non-volatile metal HAPs. Potential dioxins/furans emissions could result from the combustion of TDF, which can only be fired on a trial basis at a maximum amount of 15 percent on a million Btu heat input basis (as discussed in the Preliminary Determination associated with permit). Given that the use of this fuel is limited to 15 percent on a Btu basis and the Division's belief that particulate matter is a surrogate for dioxins/furans based on recently established MACT standards, the Division believes that dioxins/furans emissions will be controlled through addressing particulate matter emissions.

Particulate matter emissions, also regulated on New Source Review/Prevention of Significant Deterioration (NSR/PSD), are addressed in the *Prevention of Significant Deterioration Preliminary Determination* associated with Application 17700 for which this *112(g) Case-By-Case Maximum Achievable Control Technology Determination* is an Appendix. Please refer to the Preliminary Determination for the discussion and determination of particulate matter emission limits and associated control technology related to the fluidized bed boiler FB.

*Mercury*

Emissions of Hg result from inert solids contained in the fuel, unburned fuel hydrocarbons which agglomerate to form particles. All of the mercury emitted from the proposed boiler is expected to be particulate matter less than 10 micrometers in diameter.

Per Application 17700 (dated October 2007), Yellow Pine proposes to utilize a fabric filter baghouse (installed for particulate matter emissions control) and dry scrubber system (installed for sulfur dioxide emissions control) combination as control technologies for mercury emissions. Yellow Pine Energy proposed to limit mercury emissions based on an overall 90% removal efficiency of mercury by the fabric filter baghouse and dry scrubber system combination (as stated in the October 2007 Application 17700).

The Division also reviewed, in addition to the potential control technologies reviewed by Yellow Pine, Sodium Tetrasulfide (STS) Injection as a potential mercury emissions control technology. Sodium Tetrasulfide Injection is a liquid chemical reagent that is injected into the gas stream in as a sorbent to remove mercury from flue gas which has been used on municipal waste combustors to remove mercury. It has the benefit of reacting to form a stable mercury compound known as cinnabar that can safely be added to concrete or disposed of. This technology has been tested for coal power plant use at the pilot scale.

In April 2003, tests of sodium tetrasulfide injection for removal of mercury from coal-combustion flue gas at the Southern Research Institute (SRI) was conducted by Babcock Power Environmental Inc. (BPEI). The tests showed that sodium tetrasulfide is effective for removing mercury in coal combustion when injected upstream of a baghouse. It reduced the mercury at the baghouse outlet by about 90% for the bituminous coal, and by over 98% for the Powder River Basin (PRB) coal, when injected at 100 mg/dscm. The stated removals are based on baghouse outlet concentration with injection, compared to inlet concentration without injection. There was some removal across the baghouse without sorbent injection. Removal efficiency increased with decreasing temperature. Hydrogen sulfide was not detected in the flue gas when sodium tetrasulfide was injected during coal firing.[1] This control technology is therefore technically feasible.

[1] *Multi-Pollutant Emissions Control & Strategies Coal-Fired Power Plant Mercury Control by Injecting Sodium Tetrasulfide,* Anthony Licata, Roderick Beittel, Terence Ake, October 14 and 15, 2003, page 9.

The following table summarizes the potential control efficiencies of potential mercury emissions control technologies:

| Control Technology | Control Efficiency |
|---|---|
| Baghouse | 95% to 99.9% |
| STS Injection | 90-98% |
| Activated Carbon | 90% |
| Wet Scrubber | 90% |
| Fuel Selection Limestone Fluidized Bed and Combustion Controls | Baseline |

Sodium tetrasulfide injection was further evaluated to determine if there were economic and/or environmental impacts associated with its implementation. The pilot study was conducted firing only coal, not the several fuels as proposed by Yellow Pine. It is not known how the various fuels fired in the fluidized bed boilers will be affected by this control technology. Further, chlorine content of the fuel affects the effectiveness of this technology. With the potential variety of fuels, the chlorine content could vary during combustion. In addition, the potential costs for such new sorbents are relatively high for the proposed control efficiency which can be achieved with the combination of control technologies as proposed for $PM_{10}$, $NO_x$, and $SO_2$. Therefore, the Division is eliminating sodium tetrasulfide injection as a viable control technology.

The *National Associate of Clean Air Agencies' (NACAA's) Reducing Hazardous Air Pollutants from Industrial Boilers: Model Permit Guidance* indicates that in testing eight existing wood-fired boilers, the data suggested a MACT floor of 2.50 to 4.50 pounds per Trillion Btu of mercury emissions. The Division contends that Yellow Pine, as a new boiler, will be able to achieve the minimum mercury emissions established by this data.

Given that Yellow Pine has yet to finalize the boiler's design, the Division has determined that fabric filter baghouse, good combustion controls, and limestone/sand fluidized bed are MACT. In addition, the Division will require that TDF must have resulted from the processing of de-wired tires. Yellow Pine must obtain certification from the TDF vendor that it is 95 percent metal free, as proposed in Application 17700. Proposed SNCR and scrubber systems will also provide additional Hg emissions control. The Division has also chosen an emission limit of 2.5 lbs/$10^{12}$ Btu (which is evaluated to equate to 3.82 x $10^{-3}$ lbs/hr and 1.67 x $10^{-2}$ tons/year) as MACT at the stack outlet. This limit is applicable at all times, excluding startup and shutdown.

Combustion controls shall consist of the following for the fluidized bed boiler:

- Good Combustion Technique: Operator Practices – Maintenance of a written site specific operating procedures manual for the boiler in which operating procedures, including startup, shutdown, and malfunction are well documented in accordance with the manufacturer's specifications. The operating procedures must be updated as applicable with any equipment or operating practice changes. The procedures shall contain operating logs documenting such changes and any deviations from the operating procedures. The operating procedures manual shall be maintained in an area allowing easy access to the boiler's operator and made available for Division review and inspection upon request.

- Good Combustion Technique: Maintenance Knowledge – The boiler must be maintained in accordance with manufacturer's specifications by personnel with training specific to the boiler and operating procedures.

- Good Combustion Technique: Maintenance Practices – Maintenance of a written site specific procedures manual for best/optimum maintenance practices in accordance to the manufacturer's specifications for the boiler. Periodic evaluations, inspections, and overhauls as appropriate of the boiler must be conducted in accordance with manufacturer's specifications. The maintenance practices must be updated as applicable with any equipment or operating practice changes. The modification of these practice changes, scheduled periodic evaluation inspections and overhaul, as appropriate, and any deviations from the prescribed maintenance practices shall be well documented in maintenance logs. The maintenance practices manual(s) shall be maintained in an area allowing easy access to the boiler's operator and made available for Division review and inspection upon request.

- Good Combustion Technique: Stoichiometic (fuel/air) Ratio – Yellow Pine must continuously monitor and adjust, as applicable, the fuel/air combustion ratio of the fluidized bed boiler per the manufacturer's specifications. Yellow Pine must, at a minimum, install a stack gas oxygen analyzer to continuously monitor excess air and adjust the boiler fuel-to-air ratio for optimum efficiency. In addition, a carbon monoxide trim loop, used in conjunction with the oxygen analyzer is required to assure that incomplete combustion cannot occur due to a deficient air supply. Yellow Pine will be required to operating a CO CEMs, with no exception, at the stack of the fluidized bed boiler, which will be discussed further below. Yellow Pine must submit a request for the Division's review and approval to install continuous fuel/air ratio monitor(s) different than the ones described here. The request must be submitted 30 days prior to proposed installation of the proposed monitor(s).

- Good Combustion Technique: Fuel Quality Analysis – Yellow Pine will be required to monitor the fuel quality of each of the fuels combusted in the fluidized boiler. Yellow Pine must obtain fuel quality certification from fuel oil, TDF, biomass, and propane suppliers to ensure that the fuel is of an acceptable standard to reduce emissions. These certifications should certify sulfur content, ash content, heating value, and moisture content, as applicable. If such certification cannot be obtained, Yellow Pine must conduct initial and periodic fuel sampling and analysis of the uncertified fuel. Such periodic fuel sampling shall be conducted as fired or weekly at a minimum. Such sampling shall include, but is not limited to moisture analysis, ash content, heating value, fuel ash content, and fuel sulfur content. Yellow Pine must develop and maintain fuel-handling practices as specified by the boiler manufacturer to ensure optimum quality necessary to ensure complete combustion, and make them available for review at the Division's request.

- Good Combustion Technique: Fuel Sizing – Yellow Pine must develop fuel sizing specifications for applicable fuels (i.e. TDF and biomass) in accordance with manufacturer's specifications to ensure proper combustion efficiency of the fluidized boiler. Yellow Pine shall conduct periodic checks of the fuel sizing in accordance with the boiler manufacturer, or weekly at a minimum. Yellow Pine shall maintain logs of these checks and make them available for review at the Division's request.

- Good Combustion Technique: Combustion Air Distribution – Yellow Pine must monitor and adjust, when applicable, the air distribution system in accordance with the boiler manufacturer's specifications. Yellow Pine shall maintain logs of such combustion air distribution monitoring and adjusting, and make them available for review at the Division's request.

- Good Combustion Technique: Fuel Dispersion – Yellow Pine must monitor and adjust, when applicable, the fuel dispersion in accordance with the boiler manufacturer's specifications. Yellow Pine shall maintain logs of such fuel dispersion monitoring and adjusting, and make them available for review at the Division's request.

Initial performance tests are required to demonstrate compliance with the Hg emission limits. Initial performance testing must be conducted within 60 days after achieving the maximum production rate at which the boiler will be operated, but not later than 180 days after the initial startup of the boiler. Performance tests are required every 12 months thereafter. Yellow Pine must use EPA Test Method 29 as specified in 40 CFR Part 60 Appendix A to demonstrate compliance with the applicable Hg limits. Mercury emission rates shall be determined using EPA Test Method 19 F-Factor methodology in Appendix A of Part 60. Control equipment and all required combustion control monitors discussed above must be installed and operating during testing.

The Hg emissions performance tests must be conducted with the boiler operating at maximum load. During the performance tests for Hg emissions, Yellow Pine must then determine, based on the 6-minute opacity averages, the opacity value corresponding to the 99 percent upper confidence level of a normal distribution of average opacity values at which the fluidized bed boiler complies with applicable limits. Testing shall be conducted in accordance with applicable test method and Division's *Procedures for Testing and Monitoring Sources of Air Pollutants*.

The 112(g) selection for the fluidized bed boiler is summarized in the table below.

| Pollutant | Control Technology | Proposed 112(g) Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| Hg | Fabric Filter Baghouse, SNCR for $NO_x$ control and scrubber system for $SO_2$control, Good Combustion Controls, and Limestone Fluidized Bed | $2.5 \times 10^{-5}$ lbs/$10^6$Btu | 3-run test average | Performance testing |
| Hg | Wire Content of Tires used to make TDF | 0% | None | Vendor Certification or Fuel Analysis |
| Hg | Metal Content of TDF | <5% | None | Vendor Certification or Fuel Analysis |

To demonstrate compliance with fuel usage limits, Yellow Pine must maintain fuel usage records. These records must track the amount and type of each fuel burned on a daily basis, and must be maintained for a period of five years from the date they were generated. Yellow Pine is required to submit the results of all initial and required periodic performance testing and fuel analysis on a quarterly basis for review. Any excess emissions, exceedances, or excursions as described in the permit of the proposed emission limits and/or operating parameter limitations shall be reported during the quarterly reporting period.

Combustion controls monitoring, record keeping, and reporting as previously described shall consist of the following for the fluidized bed boiler:

- Good Combustion Technique: Operator Practices – Maintenance of a written site specific operating procedures manual in which operating procedures, including startup, shutdown, and malfunction are well documented in accordance with the manufacturer's specifications. The operating procedures must be updated as applicable with any equipment or operating practice changes. The procedures shall contain operating logs documenting such changes and any deviations from the operating procedures. The operating procedures manual shall be maintained in an area allowing easy access to the boiler's operator and made available for Division review and inspection upon request.

- Good Combustion Technique: Maintenance Knowledge – The boiler must be maintained in accordance with manufacturer's specifications by personnel with training specific to the boiler and operating procedures.

- Good Combustion Technique: Maintenance Practices – Maintenance of a written site specific procedures manual for best/optimum maintenance practices in accordance to the manufacturer's specifications for the boiler. Periodic evaluations, inspections, and overhauls as appropriate of the boiler must be conducted in accordance with manufacturer's specifications. The maintenance practices must be updated as applicable with any equipment or operating practice changes. The modification of these practice changes, scheduled periodic evaluation inspections and overhaul, as appropriate, and any deviations from the prescribed maintenance practices shall be well documented in maintenance logs. The maintenance practices manual shall be maintained in an area allowing easy access to the boiler's operator and made available for Division review and inspection upon request.

- Good Combustion Technique: Stoichiometic (fuel/air) Ratio – Yellow Pine must continuously monitor and adjust, as applicable, the fuel/air combustion ratio of the fluidized bed boiler per the manufacturer's specifications. Yellow Pine must, at a minimum, install a stack gas oxygen analyzer to continuously monitor excess air and adjust the boiler fuel-to-air ratio for optimum efficiency. In addition, a carbon monoxide trim loop, used in conjunction with the oxygen analyzer is required to assure that incomplete combustion cannot occur due to a deficient air supply. Yellow Pine will be required to operating a CO CEMs, with no exception, at the stack of the fluidized bed boiler. Yellow Pine must submit a request for the Division's review and approval to install continuous fuel/air ratio monitor(s) different than the ones described here. The request must be submitted 30 days prior to proposed installation of the proposed monitor(s). The records resulting from this monitoring shall be maintained on site, unless otherwise required to be submitted to the Division during the quarterly reporting.

- Good Combustion Technique: Fuel Quality Analysis – Yellow Pine will be required to monitor the fuel quality of each of the fuels combusted in the fluidized boiler. Yellow Pine must obtain fuel quality certification from fuel oil, TDF, biomass, and propane suppliers to ensure that the fuel is of an acceptable standard to reduce emissions. These certifications should certify sulfur content, ash content, heating value, and moisture content, as applicable. If such certification cannot be obtained, Yellow Pine must conduct initial and periodic fuel sampling and analysis of the uncertified fuel. Such periodic fuel sampling shall be conducted as fired weekly at a minimum. Such sampling shall include, but is not limited to moisture analysis, ash content, heating value, fuel ash content, and fuel sulfur content. Yellow Pine must develop and maintain fuel-handling practices as specified by the boiler manufacturer to ensure optimum quality necessary to ensure complete combustion, and make them available for review at the Division's request. Such fuel sampling results and/or vender certifications must be submitted for review during the quarterly reporting period.

- Good Combustion Technique: Fuel Sizing – Yellow Pine must develop fuel sizing specifications for applicable fuels (i.e. TDF and biomass) in accordance with manufacturer's specifications to ensure proper combustion efficiency of the fluidized boiler. Yellow Pine shall conduct periodic checks of the fuel sizing in accordance with the boiler's manufacturer, or weekly at a minimum. Yellow Pine shall maintain logs of these checks and make them available for review at the Division's request.

- Good Combustion Technique: Combustion Air Distribution – Yellow Pine must monitor and adjust, when applicable, the air distribution system in accordance with the boiler manufacturer's specifications. Yellow Pine shall maintain logs of such combustion air distribution monitoring and adjusting, and make them available for review at the Division's request.

- Good Combustion Technique: Fuel Dispersion – Yellow Pine must monitor and adjust, when applicable, the fuel in accordance with the boiler manufacturer's specifications. Yellow Pine shall maintain logs of such fuel dispersion monitoring and adjusting, and make them available for review at the Division's request.

Yellow Pine is also required report any 3-hour block period during which the average opacity the fluidized bed boiler, as measured by the COMS, exceeds the opacity value established during performance testing at which the fluidized bed boiler complies with applicable limits.

*Acid Gases*

Hydrogen chloride, HCl serves as a reasonable surrogate for control of inorganic (acid gas) HAPs. Hydrogen chloride emissions result mostly from the release of chlorine bound in the fuel during combustion. The chlorine content of the proposed biomass fuel which will be combusted in the fluidized bed boiler is not known.

Yellow Pine did not evaluate HCl emissions control technologies in its October 2007 Permit Application or its August 2008 112(g) Application. Although such control devices were not evaluated, the Division believes that emission control technologies investigated to control sulfur dioxide emissions are applicable for the control of HCl emissions. For a full discussion of the investigated sulfur dioxide emissions control technologies, please see the Prevention of Significant Deterioration Preliminary Determination associated with Application 17700. In the document, the sulfur dioxide control technology chosen was a dry scrubber system used in conjunction with good combustion controls as described for Hg control above and the sand/limestone fluidized bed of the boiler.

The *National Associate of Clean Air Agencies' (NACAA's) Reducing Hazardous Air Pollutants from Industrial Boilers: Model Permit Guidance* indicates that in testing 11 existing wood-fired boilers, the data suggested a MACT floor of 0.006 to 0.012 pounds per million Btu of HCl emissions. The Division contends that Yellow Pine, as a new boiler, will be able to achieve the minimum mercury emissions established by this data.

Given that Yellow Pine has yet to finalize the boiler's design, the Division has determined that the dry scrubber, good combustion controls, and limestone/sand fluidized bed are MACT. The Division has also chosen emission limit of 0.006 lbs/$10^6$ Btu (which is evaluated to equate to 9.2 lbs/hr and 40.2 tons/year) as MACT at the stack outlet. This limit is applicable at all times, excluding startup and shutdown.

Initial performance tests are required to demonstrate compliance with the HCl emission limits. Initial performance testing must be conducted within 60 days after achieving the maximum production rate at which the boiler will be operated, but not later than 180 days after the initial startup of the boiler. Performance tests are required every 12 months thereafter. Yellow Pine must use EPA Test Method 26 or EPA Test Method 26A as specified in 40 CFR Part 60 Appendix A to demonstrate compliance with the applicable HCl limits. Hydrogen Chloride emission rates shall be determined using EPA Test Method 19 F-Factor methodology in Appendix A of Part 60. Control equipment and all required combustion control monitors discussed above must be installed and operating during testing.

The HCl emissions performance tests must be conducted with the boiler operating at maximum load. During the performance tests for HCl emissions, Yellow Pine must determine lime injection flow rate of dry scrubber system in terms of pounds per million Btu heat input at which the fluidized bed boiler complies with HCl emissions limit. Testing shall be conducted in accordance with applicable test method and Division's *Procedures for Testing and Monitoring Sources of Air Pollutants*.

The 112(g) selection for the fluidized bed boiler is summarized in the table below.

| Pollutant | Control Technology | Proposed 112(g) Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| HCl | Scrubber system for $SO_2$ control, Good Combustion Controls, and Limestone Fluidized Bed | 0.006 lbs/$10^6$Btu | 3-run test average | Performance testing |

To demonstrate compliance with fuel usage limits, Yellow Pine must maintain fuel usage records. These records must track the amount and type of each fuel burned on a daily basis, and must be maintained for a period of five years from the date they were generated. Yellow Pine is required to submit the results of all initial and required periodic performance testing and fuel analysis on a quarterly basis for review. Any excess emissions, exceedances, or excursions as described in the permit of the proposed emission limits and/or operating parameter limitations shall be reported during the quarterly reporting period.

Yellow Pine must also continuously monitor and record the lime injection flow rate for the scrubber system. Yellow Pine must report any instances in which the lime injection rate is less than 80 percent of the tested lime injection rate at which the fluidized bed demonstrated compliance with the HCl limit.

Combustion controls monitoring, record keeping, and reporting are as previously described for Hg emissions control.

*Organic HAPs*

EPA has determined that CO emissions can serve as a reasonable surrogate for control of the organic HAPs. Carbon Monoxide is also regulated as a NSR/PSD pollutant, which is addressed in the *Prevention of Significant Deterioration Preliminary Determination* associated with Application 17700 for which this *112(g) Case-By-Case Maximum Achievable Control Technology Determination* is an Appendix. Please refer to the Preliminary Determination for the discussion and determination of CO emission limits and associated control technology related to the fluidized bed boiler FB.

### 5.5.2 Auxiliary Boiler

The Division has reviewed the proposed operational restrictions that the applicant has proposed as MACT for the boiler. The Division believes that operating hours limitations and good combustion control standards will ensure the facility remains in compliance with the Air Quality Permit.

Yellow Pine proposes to limit operating hours of the auxiliary boiler to 250 hours per calendar year. To ensure compliance with the operating hours limitation, Yellow Pine must install a non-resettable hour meter to record the operating hours of the boiler. Yellow Pine must also limit the fuel types to propane and low sulfur fuel oil, at a minimum for the auxiliary boiler. Yellow Pine proposes to use low sulfur fuel oil with a sulfur content of 0.05 percent. By the year 2010, the emergency generator and water fuel pump engine to be located at the facility will require the use of diesel fuel with the fuel sulfur content of 15 parts per million (ppm). Therefore, to reduce facility-wide emissions, Yellow Pine will be allowed to only burn fuel oil in the auxiliary boiler with a sulfur content less than or equal to 15 parts per million (ppm) by 2010. Yellow Pine must also employ good combustion controls for the auxiliary boiler.

## 6.0 AIR QUALITY ANALYSIS

Following the procedures as specified in the "Guidelines for Ambient Impact Assessment of Toxic Air Pollutant Emissions", modeling done by both the Division and the company indicate that the maximum ground level concentrations for all toxic air pollutants that will be emitted from this operation are well below the acceptable ambient concentrations. The TIA is addressed in the *Prevention of Significant Deterioration Preliminary Determination* associated with Application 17700 for which this *112(g) Case-By-Case Maximum Achievable Control Technology Determination* is an Appendix. Please refer to the Preliminary Determination for the discussion of the TIA and associated modeling.

Toxics analysis indicates that silver emissions must be limited to 0.63 pounds per hour to demonstrate compliance with the Toxics Guidelines. Therefore, Yellow Pine will be required to conduct initial performance tests with the boiler operating at maximum load. Yellow Pine must use EPA Test Method 29 as specified in 40 CFR Part 60 Appendix A to demonstrate compliance with the applicable Ag limits. Silver emission rates shall be determined using EPA Test Method 19 F-Factor methodology in Appendix A of Part 60. Control equipment and all required combustion control monitors discussed above must be installed and operating during testing.

Initial performance testing for silver] must be conducted within 60 days after achieving the maximum production rate at which the boiler will be operated, but not later than 180 days after the initial startup of the boiler. Yellow Pine must report the results of this test during the first quarterly report following testing.

In addition, a review of the modeling indicated that no physical barrier to public access was delineated on the project site map. Therefore, such a barrier is required to validate the modeling.

As the result, the toxic emissions impact from the construction and operation of the proposed facility is expected to be insignificant.

# APPENDIX B – Draft SIP Construction Permit

# APPENDIX C – Yellow Pine Energy Company, LLC List of PSD Permit Application and Supporting Data Documents

# List of Permit Application Supporting Data Documents

1. PSD Permit Application No. 17700, dated September 27, 2007
2. Information Request Letter Dated October 19, 2007
3. Additional Information Package Dated November 30, 2007
4. Information Request Letter Dated December 18, 2007
5. Additional Information Package Dated January 10, 2007
6. Information Request Letter Dated February 15, 2008
7. Information Request Letter Dated April 3, 2008
8. Additional Information Package Dated April 16, 2008
9. Additional Information Package Dated May 2008
10. Information Request Letter Dated June 17, 2008
11. Additional Information Package Dated August 1, 2008
12. Information Request Letter Dated November 12, 2008
13. Additional Information Package Dated December 3, 2008

The above list of Documents can be located at the website address: http://www.georgiaair.org/airpermit/.

Locate the documents by selecting the Permits and Title V Applications tab on the left side of the screen. Then select from the pull down window. The documents can be obtained under the *Yellow Pine Energy Company, LLC, Fort Gaines Online Docket*.

# APPENDIX D – EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review