5.0 BEST AVAILABLE CONTROL TECHNOLOGY

5.1 METHODOLOGY

BACT analyses were performed in accordance with the EPA top-down method. As previously described in Section 3.4.1, the top-down methodology consists of the following five steps:

- Step 1—Identify all available control technologies for each PSD pollutant subject to review.
- Step 2—Eliminate all technically infeasible control technologies.
- Step 3—Rank the remaining control technologies by control effectiveness.
- Step 4—Evaluate the feasible control technologies, beginning with the most efficient, with respect to economic, energy, and environmental impacts.
- Step 5—Select as BACT the most effective control technology that is not rejected based on adverse economic, environmental, and/or energy impacts.

The first step in the top-down BACT procedure is the identification of all available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, postprocess stack controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information used to identify control alternatives included:

- EPA reasonably available control technology (**R**ACT)/**B**ACT/lowest achievable emission rate (**L**AER) **C**learinghouse (RBLC) via the RBLC Information system database.
- Recent permits for biomass-fired power projects.
- FDEP BACT determinations for similar facilities.
- Environmental Consulting & Technology, Inc.'s (ECT's) experience for similar projects.

Following the identification of available control technologies, the next step in the analysis is to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the EPA NSR Workshop Ma-

nual (EPA, 1990a). The third step in the top-down BACT process is the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness.

If the top-case control technology with the highest removal efficiency is selected as BACT, an assessment of collateral environmental impacts is conducted to determine whether such impacts would deem the control technology unacceptable. If the most efficient control technology is not selected as BACT, an assessment of energy, environmental, and economic impacts is then performed. If assessed, the economic analysis employed the procedures found in the Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual, Sixth Edition (EPA, 2002).

The fifth and final step is the selection of a BACT emission limitation corresponding to the most stringent, technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds.

As defined by Rule 62-210.200(40), F.A.C., BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR 60), NESHAPs (40 CFR 61 and 63), and FDEP emission standards (Chapter 62-296, Stationary Sources—Emission Standards, F.A.C.). The NSPS, NESHAPs, and Florida emission standards applicable to GREC were previously discussed in Sections 4.1, 4.2, and 4.5, respectively. All of the BACT emission limitations proposed for GREC are more stringent than the applicable federal and state standards cited in these sections.

As shown in Table 3-2 of Section 3.3, annual GREC emissions of NO_x, SO_2, CO, VOC, and PM/PM_{10} are projected to exceed the PSD significance rates for these pollutants. A BACT analysis is therefore required for each GREC emission source that will emit these pollutants. Accordingly, BACT analyses were conducted for the following GREC emission sources:

- BFB boiler.
- Emergency firewater pump and generator diesel engines.

- Mechanical draft cooling tower.
- Biomass fuel and material (fly ash and DSI sorbent) storage and handling systems.

The BFB boiler and emergency diesel engines will emit pollutants associated with fuel combustion including NO_x, SO_2, CO, VOC, and PM/PM_{10}. BACT analyses were therefore conducted for each of these combustion-related PSD pollutants for the BFB boiler and emergency diesel engines. The mechanical draft cooling tower and material storage and handling systems will only emit PM/PM_{10}. The BACT analysis for these GREC emission sources was therefore confined to PM/PM_{10}.

The principal GREC emission source is the BFB boiler. Emissions from the BFB boiler comprise approximately 95 percent of total estimated GREC project annual emissions. Accordingly, the primary emphasis of the BACT analysis conducted for GREC was directed to the BFB boiler. The BFB boiler will be equipped with a comprehensive state-of-the art emission control system that includes the inherent emission reduction benefits of the bubbling fluidized bed process, DSI for acid gas control, fabric filter for PM/PM_{10} control, and a SCR system for NO_x control.

Control technology analyses using the five-step top-down BACT method are provided for in Section 5.3 (NO_x), Section 5.4 (SO_2), Section 5.5 (CO and VOC), and Section 5.6 (PM/PM_{10}). CO and VOC are addressed in one section since these pollutants have a common origin (i.e., both are products of incomplete fuel combustion) and similar available control technologies.

5.2 BACT ANALYSIS FOR STARTUP AND SHUTDOWN EVENTS

GREC will be a base load unit with an estimated capacity factor of 90 percent. The frequency of unit startups and shutdowns will therefore be low. Each unit startup will also be preceded by a period of time when the unit is offline, during which there will be no emissions from the BFB boiler. Startups and shutdowns of the BFB boiler will be conducted using best operational practices to minimize emissions and have a duration consis-

tent with process and safety considerations. The fabric filter will be used at all times, i.e. during startup and shutdown. However, the DSI and SCR control systems cannot be placed in service until the boiler flue gas conditions reach specific criteria for each control system. Excess emissions associated with startup and shutdown events were previously discussed in Section 2.5.

5.3 EVALUATION OF ALTERNATIVE ELECTRICAL GENERATION TECHNOLOGIES

As discussed in Section 5.1, the first step in a BACT determination process is to identify all available control technologies that could potentially be used to minimize the emissions for the pollutant under evaluation. Control technologies typically considered in a BACT analysis include process modifications that reduce the formation of pollutants and postprocess emission control systems that reduce emissions after the pollutants are formed. An example of the former is the use of staged combustion to alter the combustion process and reduce the formation of NO_x. The use of SCR to reduce NO_x following its formation in the combustion process is an example of a postprocess emission control system. These types of control technologies, when applicable, are appropriately considered in a BACT analysis.

Evaluation of process alternatives that would involve completely redefining the design of the proposed process are not required to be considered (reference the 1990 Draft NSR Workshop Manual, Section IV.A.3). Alternative electrical generating processes, such as natural gas-fired, coal-fired, or IGCC plants, represent completely different power generation plant designs compared to the biomass-fired BFB combustion technology selected for GREC. While all electrical generation technologies generate electricity, the technical basis for the BFB combustion technology is substantially different from a natural gas-fired, coal-fired, or IGCC plant. Since a natural gas-fired, coal-fired, or IGCC electrical generating plant represents a completely different process compared to biomass-fired BFB combustion technology, a BACT analysis of these alternative electrical generation technologies is not required because these process alternatives would redefine the design of GREC.

5.4 BACT ANALYSIS FOR NO_X

5.4.1 BUBBLING FLUIDIZED BED (BFB) BOILER

NO_x emissions from combustion sources consist of two components: oxidation of atmospheric nitrogen contained in the combustion air (thermal NO_x and prompt NO_x) and conversion of chemically bound fuel nitrogen (fuel NO_x). Thermal NO_x results when atmospheric nitrogen is oxidized at the high temperatures occurring in the boiler firebox to yield nitric oxide (NO), NO_2, and other oxides of nitrogen. Most thermal NO_x is formed in high-temperature areas where combustion air has mixed sufficiently with the fuel to produce a peak temperature. The rate of formation of thermal NO_x is a function of residence time and free oxygen and varies exponentially with peak flame 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 oxidation of chemically bound nitrogen present in the fuel. Most boiler NO_x emissions originate as NO. NO generated by the combustion process is subsequently further oxidized downstream of the combustion zone or in the atmosphere to the more stable NO_2 molecule.

5.4.1.1 Available NO_x Control Technologies

Available technologies for controlling NO_x emissions from BFB boilers include combustion process modifications and postcombustion exhaust gas treatment systems. Available combustion process modifications include staged combustion using overfire air (OFA), natural gas reburn (NGR), and FGR. Available postcombustion controls include selective noncatalytic reduction (SNCR), EMx™ (formerly SCONOx™), and SCR. A description of each of these control technologies is provided in the following subsections.

Staged Combustion

Staged combustion is the process of partially delaying the combustion process for the purpose of more complete combustion and lower NO_x emissions. BFB boilers reduce NO_x by completing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame and results in one or more of the following conditions: (a) reduced oxygen in the primary flame zone; (b) reduced flame tempera-

ture; and (c) reduced residence time at peak temperature. The lower oxygen levels, flame temperatures, and residence times will suppress the formation of thermal NO_x. NO_x emission reductions of 30 to 50 percent have been achieved with staged combustion.

OFA is a form of staged combustion. In the primary combustion zone, combustion air is diverted from the BFB creating a fuel-rich zone in the lower section of the boiler. This oxygen-deficient zone decreases the conversion of fuel-bound nitrogen to NO_x. Additional combustion air is injected above the primary combustion zone to complete the combustion process. The resulting reduction in temperature decreases the production of thermal NO_x.

Natural Gas Reburn

NGR is a process that diverts some of the heat input from the main boiler combustion zone to an area above the main boiler burners. This diversion creates a secondary *reburn* combustion zone. Natural gas is injected in the reburn zone producing a slightly fuel-rich section. OFA is then added above the reburn zone to complete the combustion process. As NO_x formed in the main combustion zone is reduced by hydrocarbon fragments (free radicals) due to the combustion of natural gas in the reburn zone, it is converted to molecular nitrogen.

Flue Gas Recirculation

FGR recirculates boiler exhaust gas from the boiler outlet to the furnace, where it is reintroduced into the combustion process. Fuel/air mixing in the combustion region is increased by the recirculated flue gas during the early stages of combustion. This increased mixing results in a higher fuel/air ratio, and reduction in peak flame temperatures results in lower thermal NO_x formation. The amount of NO_x reduction is dependent upon the burner and furnace design. FGR has been demonstrated as a technically feasible technology on biomass-fired boilers.

Selective Non-Catalytic Reduction

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_x in the exhaust gas stream with injected ammonia (NH_3) or urea to yield nitrogen and water vapor. The two commercial applications of SNCR include the Electric Power Research Institute's (EPRI's) NO_xOUT and Exxon's Thermal DeNO_x processes. The two processes are similar in that either ammonia (Thermal DeNO_x) or urea (NO_xOUT) is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. Simplified chemical reactions for the Thermal DeNO_x process are as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6\ H_2O \quad (1)$$

$$4\ NH_3 + 5\ O_2 \rightarrow 4NO + 6\ H_2O \quad (2)$$

The NO_xOUT process is similar with the exception that urea is used in place of ammonia.

The critical design parameter for both SNCR processes is the reaction temperature. At temperatures below 1,600°F, rates for both reactions decrease allowing unreacted ammonia to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor Equation (1) resulting in a reduction in NO_x emissions. Equation (2) will dominate at temperatures above approximately 2,000°F, causing an increase in NO_x emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000°F.

Since Equations (1) and (2) are theoretical, some of the injected ammonia will not react completely to form nitrogen and water. This unreacted ammonia will be emitted into the atmosphere as ammonia slip. Excess ammonia in the atmosphere may produce ammonium salts and further develop into $PM_{2.5}$ or PM_{10} particles. The amount of ammonia slip emitted will depend on three factors: (1) the extent of mixing of the injected ammonia and fuel combustion products; (2) temperature in the mixing zone; and (3) residence time. Therefore, ammonia slip formation is related to the physical characteristics of the boiler and achievable NO_x control efficiency. SNCR typically achieves NO_x control efficiencies of 40 to 60 percent.

Selective Catalytic Reduction

In contrast to SNCR, SCR reduces NO_x emissions by reacting ammonia with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. Ammonia is injected upstream of the catalyst bed where the following primary reactions take place:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \quad (3)$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \quad (4)$$

The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature (i.e., in the range of 600 to 750°F). Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), ammonia/NO_x molar ratio, catalyst reactivity, catalyst age, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_x removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with ammonia theoretically requires a 1:1 molar ratio. Ammonia/NO_x molar ratios greater than 1:1 are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive ammonia slip emissions.

As is the case for SNCR, reaction temperature is critical for proper SCR operation. The optimum temperature range for SCR operation is dependent on the type of catalyst used. The two main groups of catalyst are base metal (vanadium-platinum or –titanium) and zeolite. The optimum temperature range for a vanadium-platinum catalyst is less than 500°F while the optimum temperature range for a vanadium-titanium catalyst is to 550 to 800°F. The zeolite catalyst is used for higher temperature applications and can operate effectively at temperatures as high as 1,000°F. At temperatures below the optimum range

for the specified catalyst, reduction Equations (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place resulting in an increase in NO_x emissions.

SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principle poisons include arsenic, sulfur, potassium, sodium, and calcium. The catalyst life does not include this potential for degradation that could cause early replacement of the catalyst.

Ammonia slip becomes a greater issue as the catalyst degrades because of the increased amount of ammonia injected to achieve the appropriate NO_x control. Vendors typically can provide SCR systems that have the ability to limit the concentration of ammonia slip to 10 parts per million by dry volume (ppmvd) throughout the life of the catalyst. SCR systems typically achieve NO_x control efficiencies of 70 to 80 percent.

EMx™ (SCONO$_x$™)

EMx™ (formerly referred to as SCONO$_x$™) is a multipollutant reduction catalytic control system offered by EmeraChem. EMx™ is a complex technology that is designed to simultaneously reduce NO_x, VOC, and CO through a series of oxidation/absorption catalytic reactions.

The EMx™ system employs a single catalyst to simultaneously oxidize CO to CO_2 and NO to NO_2. NO_2 formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The EMx™ oxidation/absorption cycle reactions are:

$$CO + ½\ O_2 \rightarrow CO_2 \quad (5)$$

$$NO + ½\ O_2 \rightarrow NO_2 \quad (6)$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \quad (7)$$

CO_2 produced by Equations (5) and (7) is released to the atmosphere as part of the exhaust stream.

As shown in Equation (7), the potassium carbonate catalyst coating reacts with NO_2 to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO_2 in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The EMx™ regeneration cycle reaction is:

$$KNO_2 + KNO_3 + 4\ H_2 + CO_2 \rightarrow K_2CO_3 + 4\ H_2O_{(g)} + N_2 \quad (8)$$

Water vapor and elemental nitrogen are released to the atmosphere as part of the exhaust stream. Following regeneration, the EMx™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate after both the oxidation/absorption and regeneration cycles have been completed.

The EMx™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in an appropriate temperature section of the exhaust stream. For installations above 450°F, the EMx™ catalyst is regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the EMx™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the EMx™ catalyst. The reformer catalyst works to partially reform the methane gas to hydrogen (2 percent by volume) to be used in the regeneration of the EMx™ catalysts. The reformer converts methane to hydrogen by the steam reforming reaction as shown by the following equation:

$$CH_4 + 2\ H_2O \rightarrow CO_2 + 4\ H_2 \quad (9)$$

The reformer catalyst is placed upstream of the EMx™ catalyst in a steam reformer reactor. The reformer catalyst is designed for a minimum 50-percent conversion of methane to hydrogen.

The EMx™ system has not been installed on any biomass combustion process and there are no current plans to install the EMx™ system on any biomass combustion process. Accordingly, EMx™ technology has never been demonstrated and therefore is not considered technically feasible for GREC.

5.4.1.2 Technical Feasibility and Ranking

The staged combustion process modifications described previously are technically feasible with the exception of NGR. NGR has not been demonstrated on a biomass-fired BFB boiler and, therefore, is not considered feasible for the GREC BFB boiler. Staged combustion is integral to the design of BFB technology.

Of the available postcombustion control technologies, both SNCR and SCR are feasible. The EMx™ technology has not been demonstrated on biomass-fired boilers and therefore is not considered technically feasible.

Table 5-1 provides a summary of the technical feasibility and ranking of the available NO_x control technologies. As shown, SCR in combination with staged combustion offers the highest control efficiency.

5.4.1.3 Evaluation of Control Technologies

GREC proposes to install the NO_x control technologies identified as having the highest control efficiency—staged combustion (integral to BFB technology), FGR, and SCR. Peak flame temperatures will increase when lower moisture content biomass fuels are combusted and during partial load boiler operations. During these periods, FGR will be employed to lower the peak flame temperatures. BFB technology includes several combustion design features that will inherently reduce the formation of NO_x including:

Table 5-1. Ranking of Available NO_x Control Technologies—BFB Boiler

Control Technology	Technically Feasible (Yes/No)	Control Efficiency Range (%)
Staged combustion, FGR, SCR	Yes	80 to 90
SCR	Yes	70 to 90
SNCR	Yes	40 to 60
FGR	Yes	40 to 60
Staged combustion	Yes	30 to 50
NGR	No	Not applicable

Source: ECT, 2009.

- Operation of the bed in a reducing atmosphere of approximately 30 to 40 percent of theoretical air requirements (i.e., substoichiometric combustion), which reduces the bed temperature. Bed temperature is controlled within a temperature range of approximately 1,350 to 1,700°F, which minimizes the formation of thermal NO_x.
- Combustion staging (i.e., use of OFA) to reduce peak bed combustion temperatures and formation of thermal NO_x.
- Large mass of bed material and fluidization achieves high combustion efficiency (approximately 99 percent) and stable combustion to minimize emissions, including potential excess emissions due to a change in fuel characteristics.

The economic and energy impacts associated with the installation and operation of this combination of control technologies are considered reasonable. There are also no significant collateral environmental issues that would justify rejection of these control technologies as BACT.

5.4.1.4 Proposed NO_x BACT

Table 5-2 provides a summary of biomass-fired utility and industrial size boiler (greater than 250 MMBtu/hr) NO_x BACT and LAER determinations for the past 5 years. The proposed GREC BFB boiler NO_x emission limit of 0.070 lb/MMBtu is equal to the two most recent draft LAER determinations, i.e. Concord Steam Corporation and Clean Power Berlin, LLC, which were updated on June 16, 2009, and October 26, 2009, respectively. Since LAER does not take into account economic factors, LAER is more stringent than BACT. Both of these draft LAER determinations were based on using SCR and staged combustion. Therefore, GREC LLC proposes a NO_x emission rate of 0.070 lb/MMBtu on a 30-day rolling average basis. NO_x BACT proposed for the BFB boiler is summarized as follows:

- Emission Limit—0.070 lb/MMBtu.
- Averaging Period—30-day rolling average.

Table 5 2. Summary of Biomass-Fired Power Plant NO_x BACT/LAER Determinations

RBLC ID	Faciity Name	Permit Dates		Process Description	Fuel	Throughput	Control Description	Emission Limit	Basis
		Issuance	Update						
*NH-0016	Clean Power Berlin LLC	09/25/09	10/26/09	Boiler 1	Wood chips	40.75 ton/hr wood	SCR with staged combustion	0.065 lb/MMBtu	LAER
*NH-0015	Concord Steam Corporation	02/27/09	06/16/09	Boiler #1	Biomass	32.62 tons/hr	SCR system	0.065 lb/MMBtu	LAER
WA-0329	Darrington Energy Cogeneration Power Plant	02/11/05	07/05/06	Wood waste-fired boiler	Wood waste	403 MMBtu/hr	SNCR	0.12 lb/MMBtu	BACT-PSD
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass boiler 4			SNCR	0.18 lb/MMBtu	BACT-PSD
WA-0335	Simpson Tacoma Kraft Company, LLC	05/22/07	08/21/07	Utility and large industrial sized boilers/furnaces	Wood waste	595 MMBtu/hr	Proper combustion controls with OFA	0.2 lb/MMBtu	BACT-PSD
ND-0022	Northern Sun	05/01/06	02/13/07	Wood/hull fired boiler	Biomass		Combustion controls	0.2 LB/MM BTU	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Heat energy systems for pellet processing	Wood/woodpaste	77 MMBtu/hr	Thermal oxidizers and CEMS	0.22 lb/MMBtu	BACT-PSD
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass boiler 3			SNCR	0.25 lb/MMBtu	BACT-PSD
WA-0337	Boise White Paper LLC	02/01/06	08/21/07	Utility-and large industrial-size boilers/furnaces (greater than 250 MMBtu/hr)	Wood/bark	343 MMBtu/hr	OFA system added to improve boiler combustion system; boiler has an ESP	0.3 lb/MMBtu	Other
FL-0301	Clewiston Sugar Mill and Refinery	12/06/07	12/15/08	Boiler 7 industrial sugar mill boiler firing bagasse	Bagasse	738 MMBtu/hr	Boiler design and operation (includes (OFA system)	0.31 lb/MMBtu	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Wood thermal oxiders for wood pellent process	Wood/wood paste	43 MMBtu/hr	Thermal oxidizers and CEMS	18.9 lb/hr	BACT-PSD
OH-0307	South Point Biomass Generation	04/04/06	08/16/07	Wood fired boilers (7)	Wood	318 MMBtu/hr	SCR	27.98 lb/hr	BACT-PSD
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Wood-fired cogeneration unit	Bark & waste wood	430 MMBtu/hr	SNCR	56 lb/hr	BACT-PSD
LA-0188	Bogalusa Mill	11/23/04	06/02/06	No. 12 hogged fuel boiler	Bark	787.5 MMBtu/hr	Existing OFA system with low NO_x burners in the under grate air heater system, plus good combustion practices	351.38 lb/hr	BACT-PSD

Source: ECT, 2009.

- Compliance Method—Continuous emissions monitoring in accordance with 40 CFR 75.

Table 5-3 provides a summary of the preliminary BFB boiler SCR design criteria.

5.4.2 EMERGENCY DIESEL ENGINES

GREC will include a diesel engine-driven emergency generator rated at 500 kW and a diesel engine-driven emergency firewater pump. The design power output ratings for the emergency generator and firewater pump diesel engines are 757 and 275 bhp, respectively. Excluding emergencies, each diesel engine will operate no more than 96 hr/yr for routine testing and maintenance purposes. This limit is less than the 100-hr/yr requirement for emergency engines as specified in NSPS Subpart IIII. Potential emissions for each diesel engine are based on each engine operating 500 hr/yr. Potential NO_x emission rates for the emergency generator and firewater pump diesel engines are 1.4 and 0.3 tpy, respectively.

The emergency diesel engines will be subject to the applicable emission standards of NSPS Subpart IIII for stationary compression ignition ICEs. Subpart IIII limits the combination of NO_x and NMHC emissions to 6.4 grams per kilowatt-hour (g/kWh) for a 2007 model year or later emergency generator diesel engines with an output greater than 750 bhp. For 2009 and later model year emergency firewater pump diesel engines between 175 and 300 bph, Subpart IIII limits the combination of NO_x and NMHC emissions to 4.0 g/kWh. Both of the emergency diesel engines purchased for GREC will comply with the applicable emission standards of NSPS Subpart IIII.

Compliance with the stringent NSPS Subpart IIII emission standards and limited annual operating hours are proposed as NO_x BACT for the GREC emergency generator and firewater pump diesel engines. NO_x BACT proposed for the GREC emergency diesel engines is summarized as follows:

Table 5-3. Preliminary SCR Design Criteria

Parameter	Unit	Estimated Design Value	Notes
Catalytic reaction temperature	°F	460 to 575	Alternate lower temperature may be considered
Inlet gas temperature	°F	460 to 550	Alternate lower temperature may be considered
Inlet gas flow rate	lb/hr	1,463,200	
Reducing agent		Aqueous ammonia	
Ammonia feed rate	lb/hr	350	
NO_x inlet concentration	ppmvd at 7-percent oxygen	92 (0.15 lb/MMBtu)	
NO_x outlet concentration	ppmvd at 7-percent oxygen	43 (0.07 lb/MMBtu)	
NO_x control efficiency	%	53	
Ammonia slip	ppmvd at 7-percent oxygen	10 ppm	
Catalyst life	Years	2 to 3	

Source: GREC, 2009.

- Emission Limit—Applicable standards of NSPS Subpart IIII.
- Averaging Period—Per NSPS Subpart IIII.
- Compliance Method—Engine manufacturer certification in accordance with NSPS Subpart IIII.
- Annual Operating Hours—96 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters

5.5 BACT ANALYSIS FOR SO_2

5.5.1 BUBBLING FLUIDIZED BED BOILER

Emissions of sulfur oxides from BFB boilers result from the oxidation of sulfur present in the fuel. Sulfur oxides formed during combustion are primarily SO_2, with minor amounts of sulfur trioxide (SO_3) and gaseous sulfates. These sulfur compounds form as the sulfur contained in the fuel is oxidized during the combustion process. Uncontrolled sulfur oxide emissions from biomass-fired boilers vary directly with the sulfur content. Due to the naturally occurring alkaline (i.e., calcium) content of woody biomass fuel, a significant portion of the SO_2 will react within the bed to form calcium sulfate compounds.

5.5.1.1 Available SO_2 Control Technologies

Available control technologies for reducing SO_2 emissions from BFB boilers include the inherent benefits of the BFB boiler, and use of postcombustion wet and dry flue gas desulfurization (FGD).

BFB Boiler

The BFB boiler itself provides inherent SO_2 control through the efficient mixing of the bed materials (i.e., sand and biomass fuel) and the boiler combustion gases. The wood fuel not only contains sulfur which converts to SO_2 during the combustion process, but also contains calcium. In the BFB, calcium oxides will react with the SO_2 to form calcium sulfate compounds and will be removed from the boiler as fly ash.

Wet FGD

Wet FGD systems remove SO_2 from exhaust streams by using an alkaline reagent to form sulfite and sulfate salts. Wet FGD systems typically involve the reaction of limestone and exhaust gas sulfur oxides in a spray absorber tower. Boiler exhaust gas enters at the bottom of the absorber tower, flows vertically through the limestone/water spray, passes through a mist eliminator to remove reentrained limestone slurry droplets, and then exits the tower. Ground limestone in the scrubbing slurry reacts with SO_2 in the flue gas to form calcium sulfite and calcium sulfate (i.e., gypsum). The calcium sulfite to calcium sulfate reaction is a result of oxidation, which can be inhibited or forced (i.e., by blowing compressed air into the slurry in the retention tank in the base of the tower or in an external oxidation tank) depending on the desired byproduct.

Wet FGD systems will generate wastewater and wet sludge streams requiring treatment and disposal. Gypsum slurry from the reaction tank is typically treated in a series of hydroclones. Reclaimed water from the hydroclones will be returned to the scrubber system, and gypsum solids will be sent to a vacuum filtration system. Gypsum solids from the vacuum filter system may be washed to remove contaminants and then loaded into railcars or trucks for shipment as a byproduct or mixed with fly ash, if necessary, and conveyed to a landfill.

Other wet FGD technologies include the use of lime, magnesium enhanced lime (MEL), and dual-alkali reagents and alternative scrubbing equipment such as the Chiyoda jet bubbling reactor (JBR). These wet FGD technologies achieve comparable or lower SO_2 removal efficiencies compared to the previously described limestone-forced oxidation (LSFO) wet FGD technology. Each of these wet FGD technologies is briefly described in the following paragraphs.

Lime Wet FGD

Lime wet FGD technology is similar to that described previously for limestone with hydrated lime used as the alkaline reagent instead of limestone. The primary advantage of limestone versus lime as the wet FGD reagent is the significantly lower cost of limestone.

MEL Wet FGD

In the MEL process, slaked lime containing calcium hydroxide and magnesium hydroxide is used to react with SO_2. The slurry is added to a recycle tank at the bottom of the absorber under pH control to replenish the reagent that is consumed. Calcium hydroxide in the slurry reacts with most of the SO_2 to precipitate calcium sulfite. Magnesium hydroxide reacts with the remainder of the SO_2 to form soluble magnesium salts, magnesium sulfite, and magnesium bisulfite. These soluble magnesium salts increase SO_2 capture and allow reduction in power consumption and equipment costs. Magnesium sulfite is replenished by addition of fresh lime slurry to the reaction tank.

MEL scrubber systems can achieve 98-percent SO_2 removal efficiency using absorber towers significantly smaller than limestone reagent systems. The presence of magnesium effectively increases the dissolved alkalinity and makes removal less dependent on lime dissolution. For the same removal efficiency, limestone based systems require a higher liquid-to-gas ratio. The selection of LSFO or MEL wet FGD technology is generally based on site-specific considerations involving the higher operating cost of lime and the higher capital cost of the larger absorbers and greater pumping costs of LSFO.

Dual-Alkali Wet FGD

Dual-alkali systems employ sodium- and calcium-based reagents to remove SO_2 from the flue gas and regenerate the scrubbing reagent. Due to the relatively high cost of sodium-based reagents and improvements in LSFO wet FGD technology, dual-alkali wet FGD technology is considered an inferior technology to LSFO wet FGD.

Chiyoda JBR

The Chiyoda wet FGD technology uses a unique JBR to react limestone reagent and flue gas. The flue gas is first quenched in a gas cooler prior to entry into the JBR. In the JBR, the flue gas is forced through numerous sparger pipes submerged below the absorbent liquid level. The flow of flue gas through the alkaline absorbent liquid results in mass transfer of SO_2 from the gas phase to the liquid phase. Absorbent liquid and oxidation air

is also introduced into the JBR enhancing the mixing of limestone slurry and flue gas. The treated flue gas proceeds to the upper part of the JBR, passes through a mist eliminator, and then enters the stack. The oxidized gypsum is removed from the JBR for dewatering. The Chiyoda process combines all FGD reactions in the JBR. The overall chemical reactions are identical to those of LSFO wet FGD technology.

In addition to controlling SO_2 emissions, wet FGD systems also have the cobenefit of removing PM, H_2SO_4 mist, hydrogen chloride, hydrogen fluoride, and mercury.

Dry Flue Gas Desulfurization

Dry FGD control systems include spray dryer absorber (SDA), circulating dry scrubber (CDS), and DSI (also termed in-duct sorbent injection system [IDSIS]) control technologies.

In an SDA control system, the combustion process exhaust stream passes through the SDA upstream of a PM control device (typically a fabric filter). An alkaline lime slurry is injected in the SDA using a rotary atomizer or fluid nozzles. The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO_2 are dried by heat contained in the exhaust stream. If a fabric filter is used as the PM control device, the alkaline lime reagent may further react with SO_2 that passes through the filter cake. This additional reaction in the fabric filter can also aid in the removal of additional pollutants (i.e., H_2SO_4 mist, hydrogen chloride, hydrogen fluoride, and mercury).

CDS technology uses flue gas, ash, and lime sorbent to form a fluidized bed in an absorber vessel. Water is added to the CDS absorber vessel to enhance the lime and SO_2 absorption reactions. Byproducts leave the absorber in a dry form with the flue gas for subsequent removal by a downstream PM collection device.

Dry Sorbent Injection (DSI)

DSI is another once-through dry FGD technology that uses an alkaline reagent (e.g., hydrated lime, trona, limestone, etc.) to absorb SO_2. DSI control technology injects the al-

kaline reagent in the ductwork between the air heater and the particulate collection device. No water is added to the lime or limestone or directly to the process. The sulfite/sulfate salts reaction products are then removed by the particulate collection device.

5.5.1.2 Technical Feasibility and Ranking

All of the postcombustion wet and dry FGD processes are technically feasible technologies for biomass-fired boilers. While technically feasible, wet FGD and the dry FGD SDA and CDS have not been installed on biomass-fired boilers due to the low sulfur of the biomass fuel and thus the low uncontrolled SO_2 flue gas concentrations. The removal efficiency of FGD control systems will decrease with decreasing inlet SO_2 loading. DSI technology has been applied to coal-fired boilers and proposed for biomass-fired boilers to control acid gases such as H_2SO_4 mist, hydrogen chloride, hydrogen fluoride, as well as SO_2.

Table 5-4 provides a summary of the technical feasibility and ranking of the available SO_2 control technologies.

5.5.1.3 Evaluation of Control Technologies

As previously discussed, wet FGD and dry FGD SDA and CDS systems have not been installed on biomass-fired boilers due to their low uncontrolled SO_2 flue gas concentrations. Therefore, GREC LLC proposes BFB technology and DSI as SO_2 BACT. The DSI control system in conjunction with the inherent benefits of BFB technology will provide an estimated 35-percent SO_2 control efficiency. This relatively low overall SO_2 removal efficiency is due to the low sulfur content of the biomass fuel; i.e., the GREC BFB boiler design biomass fuel mix sulfur content is only 0.009 weight percent on an as-received basis. In comparison, coal-fired power plants may combust coals containing more than 2.0 weight percent sulfur or more than 200 times higher than woody biomass. The economic and energy impacts associated with the installation and operation of this control technology are considered reasonable. There are also no significant collateral environmental issues that would justify rejection of this control technology as BACT.

Table 5-4. Ranking of Available SO_2 Control Technologies—BFB Boiler

Control Technology	Technically Feasible (Yes/No)	Control Efficiency Range* (%)
Wet FGD	Yes	90 to 98
Dry FGD—SDA and CDS	Yes	70 to 90
BFB technology and DSI	Yes	30 to 40

*Control efficiencies vary depending on the level of uncontrolled SO_2 emissions. Higher efficiencies shown for wet and dry FGD are typical values for coal-fired power plants with significantly higher fuel sulfur contents compared to woody biomass.

Source: ECT, 2009.

5.5.1.4 Proposed SO_2 BACT

Table 5-5 provides a summary of biomass-fired utility and industrial size boiler (greater than 250 MMBtu/hr) SO_2 BACT determinations for the past 5 years. The lowest BACT determination is 0.025 lb/MMBtu for Skagit County Lumber Mill in Washington. This BACT emission limit is based on the uncontrolled emission factor contained in AP-42 Section 1.6, Wood Residue Combustion in Boilers. There are no control technologies installed at Skagit County Lumber Mill to reduce the uncontrolled SO_2 emissions. GREC proposes an SO_2 BACT emission rate of 0.041 lb/MMBtu on a 30-day rolling average basis.

SO_2 BACT emission limits proposed for the GREC BFB boiler are summarized as follows:

- Emission Limits—0.041 lb/MMBtu.
- Averaging Period—30-day rolling average.
- Compliance Method—Continuous emissions monitoring in accordance with 40 CFR 75.

5.5.2 EMERGENCY DIESEL ENGINES

The emergency generator and firewater pump diesel engines will each be fired with ULSD fuel oil containing no more than 0.0015 percent sulfur by weight. Excluding emergencies, each diesel engine will operate no more than 96 hr/yr for routine testing and maintenance purposes. Potential emissions for each diesel engine are based on each engine operating 500 hr/yr. Potential SO_2 emission rates are for the emergency generator and firewater pump diesel engines are .0.002 and 0.0008 tpy, respectively.

The diesel engines will emit SO_2 due to thermal oxidation of sulfur contained in the fuel oil. The only technically and economically feasible technology available to control SO_2 from emergency diesel engines is the use of low-sulfur fuel oil.

Table 5 5. Summary of Coal-Fired Power Plant SO_2 BACT Determinations

RBLC ID	Facility Name	Permit Dates		Process Description	Fuel	Throughput	Control Description	Emission Limit	Basis
		Issuance	Update						
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Wood-fired cogeneration unit	Bark and waste wood	430 MMBtu/hr		0.025 lb/MMBtu	BACT-PSD
ND-0022	Northern Sun	05/01/06	02/13/07	Wood/hull fired boiler	Biomass			0.47 lb/MMBtu	BACT-PSD
VA-0298	International Biofuels, Inc	12/13/05	09/17/07	Wood thermal oxidizers for wood pellet process	Wood/wood paste	43 MMBtu/hr	Thermal oxidizers and CEMS	2.2 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc	12/13/05	09/17/07	Heat energy systems for pellet processing	Wood/woodpaste	77 MMBtu/hr	Thermal oxiders and CEMS	3.9 lb/hr	BACT-PSD
OH-0307	South Point Biomass Generation	04/04/06	08/16/07	Wood fired boilers (7)	Wood	318 MMBtu/hr	Spray dryer adsorber or dry sodium bicarbonate injection system	22.13 lb/hr	BACT-PSD
AL-0223	Stevenson Mill	07/14/06	07/23/07	No. 2 wood-fired boiler	Biomass	620 MMBtu/hr		93 lb/hr	BACT-PSD
LA-0188	Bogalusa Mill	11/23/04	06/02/06	No. 12 hogged fuel boiler	Bark	787.5 MMBtu/hr	Limit annual fuel oil capacity factor to less than 10 percent	1,209.75 lb/hr	BACT-PSD
WA-0337	Boise White Paper LLC	02/01/06	08/21/07	Kraft pulp and paper processes/recovery furnace	Black liquor solids	3.4 MMlb/day		1301 tpy	BACT-PSD
WA-0337	Boise White Paper LLC	02/01/06	08/21/07	Kraft pulp and paper processes/recovery furnace	Black liquor solids	3.4 MMlb/day		1301 tpy	BACT-PSD

Sources: EPA, 2009.
ECT, 2009.

The exclusive use of ULSD fuel oil and constraints on annual operations for maintenance and testing purposes are proposed as SO_2 BACT for the emergency diesel engines. SO_2 BACT proposed for the GREC emergency diesel engines is summarized as follows:

- Emission Limit—Exclusive use of ULSD fuel oil.
- Compliance Method—Supplier certifications of fuel oil sulfur content.
- Annual Operating Hours—96 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters.

5.6 BACT ANALYSIS FOR CO AND VOC

5.6.1 BFB BOILER

Fuel combustion CO and VOC emissions result from the incomplete combustion of carbon and organic compounds contained in the fuel. Factors affecting CO and VOC emissions include firing temperatures, excess oxygen and residence time in the combustion zone, and combustion area mixing characteristics. An increase in combustion zone residence time and oxygen levels and improved mixing of fuel and combustion air will increase oxidation rates and decrease CO and VOC emission rates. BFB boilers are designed and operated to minimize the formation of CO and VOC by maximizing the combustion area mixing of the biomass fuel and combustion air.

In general, emissions of NO_x and CO/VOC are inversely related (i.e., decreasing NO_x emissions will result in an increase in CO/VOC emissions and vice-versa). Accordingly, boiler combustion controls designed to lower NO_x emissions (e.g., lower combustion temperatures) would also be expected to cause a collateral increase in CO and VOC emissions. Accordingly, boiler combustion design and operation requires a balancing of the competing goals to minimize the formation of both NO_x and CO/VOC.

5.6.1.1 Available CO and VOC Control Technologies

Three control technologies are available for reducing CO and VOC emissions from combustion sources: combustion controls, thermal oxidation, and catalytic oxidation.

Combustion Controls

Optimization of the design, operation, and maintenance of the boiler combustion system is the primary technology available for reducing CO and VOC emissions. Combustion process controls involve boiler combustion designs and operating practices that improve the oxidation process and minimize incomplete combustion. Key combustion design and operating parameters include sufficient excess air, high combustion temperatures, adequate residence time, and good mixing of the combustion air and fuel.

Thermal Oxidation

A thermal oxidizer employs high temperature (approximately 1,500°F) combustion to achieve a 90- to 95-percent oxidization rate of CO and VOC to CO_2 and water. The thermal oxidizer components are subject to fouling by PM. Accordingly, for biomass-fired boilers, the thermal oxidizer would need to be located downstream of the boiler's PM control device. In addition, a thermal oxidizer requires a source of supplemental fuel, typically natural gas, to raise the exhaust stream to the required oxidation temperature.

Catalytic Oxidation

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote the oxidation of CO and VOC to CO_2 and water at temperatures approximately 50 percent lower than would be necessary for oxidation without a catalyst. The operating temperature range for conventional oxidation catalysts is between 650 and 1,150°F.

The efficiency of CO and VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO and VOC oxidation will occur at any temperature above roughly 500°F. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst that will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time, which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an in-

crease in pressure drop across the catalyst bed. Oxidation catalyst systems are typically designed for a CO oxidation efficiency of 80 to 90 percent. The efficiency of VOC oxidation is approximately 50 percent.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies. Oxidation catalysts are also subject to masking and/or blinding by fly ash contained in the exhaust stream of a pulverized coal boiler. There are no known installations of catalytic oxidation technology to control CO and VOC emissions from biomass-fired boilers.

Table 5-6 provides a summary of the technical feasibility and ranking of the available CO and VOC control technologies.

5.6.1.2 Technical Feasibility

The only CO and VOC control technologies considered technically feasible for biomass-fired boilers is combustion controls and thermal oxidation. Thermal oxidation technology is considered impractical due to the required operating temperature and need for supplemental fuel. Due to naturally occurring biomass fuel contaminants and high flue gas temperature required, oxidation catalyst technology is not considered technically feasible for the GREC BFB boiler.

5.6.1.3 Proposed CO and VOC BACT

Tables 5-7 and 5-8 provide a summary of biomass-fired utility and industrial size boiler (greater than 250 MMBtu/hr) CO and VOC BACT determinations, respectively for the past 5 years. GREC LLC proposes good combustion controls as CO and VOC BACT. The proposed CO BACT emission rate of 0.12 lb/MMBtu is lower than any previous BACT determination, as shown in Table 5-7. Similarly, good combustion controls will result in a VOC emission rate of only 0.013 lb/MMBtu per hour. This proposed VOC BACT emission rate is lower than any previous BACT determination, as shown in Table 5-8.

Table 5-6. Ranking of Available CO and VOC Control Technologies—BFB Boiler

Control Technology	Technically Feasible (Yes/No)	Control Efficiency Range* (%)
Thermal oxidation	Yes	90 to 95
Catalytic oxidation	No	80 to 90
Combustion controls	Yes	25 to 50

*Control efficiencies vary depending on the level of uncontrolled CO and VOC emissions.

Source: ECT, 2009.

Table 5 7. Summary of Biomass-Fired Boiler CO BACT Determinations

RBLC ID	Faciity Name	Permit Dates		Process Description	Fuel	Throughput	Control Description	Emission Limit	Basis
		Issuance	Update						
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Heat energy systems for pellet processing	Wood/woodpaste	77 MMBtu/hr	Thermal oxidizers and CEMS	0.19 lb/MMBtu	BACT-PSD
WA-0335	Simpson Tacoma Kraft Company, LLC	05/22/07	08/21/07	Utility and large industrial sized boilers/furnaces	Wood waste	595 MMBtu/hr	OFA system installed in 2006 to improve combustion conditions.	0.35 lb/MMBtu	BACT-PSD
WA-0329	Darrington Energy Cogeneration Power Plant	02/11/05	07/05/06	Wood waste-fired boiler	Wood waste	403 MMBtu/hr	Good combustion practices	0.35 lb/MMBtu	BACT-PSD
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass boiler 4			Good combustion practice	0.43 lb/MMBtu	BACT-PSD
ND-0022	Northern Sun	05/01/06	02/13/07	Wood/hull fired boiler	Biomass		Good combustion practices	0.63 lb/MMBtu	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Wood thermal oxidizers for wood pellet process	Wood/wood paste	43 MMBtu/hr	Thermal oxidizers and CEMS	16.3 lb/hr	BACT-PSD
OH-0307	South Point Biomass Generatic	04/04/06	08/16/07	Wood fired boilers (7)	Wood	318 MMBtu/hr	Oxidation catalyst	31.8 lb/hr	BACT-PSD
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Wood-fired cogeneration unit	Bark and waste wood	430 MMBtu/hr		400 lb/hr	BACT-PSD
LA-0188	Bogalusa Mill	11/23/04	06/02/06	No. 12 hogged fuel boiler	Bark	787.5 MMBtu/hr	Existing OFA system and good combustion practices	491.45 lb/hr	BACT-PSD
WA-0337	Boise White Paper LLC	02/01/06	08/21/07	Utility-and large industrial-size boilers/furnaces (greater than 250 MMBtu/hr)	Wood/bark	343 MMBtu/hr	OFA system added to improve the boiler's combustion system; boiler has an ESP	500 ppmvd	Other

Sources: EPA, 2009.
ECT, 2009.

Table 5-8. Summary of Biomass-Fired Boiler VOC BACT Determinations

RBLC ID	Facility Name	Permit Dates		Process Description	Fuel	Throughput	Control Description	Emission Limit	Basis
		Issuance	Update						
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Wood-fired cogeneration unit	Bark and waste wood	430 MMBtu/hr		0.019 lb/MMBtu	BACT-PSD
AR-0083	Potlatch Corporation - Ozan Unit	07/26/05	12/22/05	Wood fired boiler	Wood chips	110,000 lb/hr	Good combustion practices	0.034 lb/MMBtu	BACT-PSD
AR-0084	Potlatch Corporation - Ozan Unit	07/26/05	12/22/05	Wood fired boiler	Wood chips	110,000 lb/hr	Good combustion practices	0.034 lb/MMBtu	BACT-PSD
AR-0083	Potlatch Corporation - Ozan Unit	07/26/05	12/22/05	Kilns 1 through 4	Steam heated	265 MMbf annually	Proper operation	3.5 lb/MMbf	
AR-0084	Potlatch Corporation - Ozan Unit	07/26/05	12/22/05	Kilns 1 through 4	Steam heated	265 MMbf annually	Proper operation	3.5 lb/MMbf	
OH-0307	South Point Biomass Generation	04/04/06	08/16/07	Wood fired boilers (7)	Wood	318 MMBtu/hr	Good combustion practices and use of oxidation catalyst	4.06 lb/hr	BACT-PSD
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Anti-mold spray system		300 MMf/yr	Drip-free design	9 tpy	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Rotary and fuel dryer processing	Wood	65.6 tph	Wood fired thermal oxidizers for rotary dryers	37.8 lb/hr	BACT-PSD
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	7. Dry kilns		300 MM board f/yr	Computerized steam management system	54 tpy	BACT-PSD

Sources: EPA, 2009.
ECT, 2009.

CO and VOC BACT emission limits proposed for the GREC BFB boiler are summarized as follows:

- CO Emission Limit—0.120 lb/MMBtu.
  - Averaging Period—30-day rolling average.
  - Compliance Method— Continuous emissions monitoring in accordance with 40 CFR 60.
- VOC Emission Limit—0.013 lb/MMBtu.
  - Averaging Period—Stack test duration.
  - Compliance Method— Stack test using EPA reference methods.

5.6.2 EMERGENCY DIESEL ENGINES

The formation mechanism of CO and VOC, available control technologies, and control technology technical feasibility described for the BFB boiler also generally apply to the emergency diesel engines. Excluding emergencies, each diesel engine will operate no more than 96 hr/yr for routine testing and maintenance purposes. Potential emissions for each diesel engine are based on each engine operating 500 hr/yr. Potential CO emission rates are for the emergency generator and firewater pump diesel engines are 1.5 and 0.4 tpy, respectively. Potential VOC emission rates are for the emergency generator and firewater pump diesel engines are 0.6 and 0.1 tpy, respectively.

The only CO and VOC control technology considered technically feasible for the GREC ULSD-fired emergency diesel engines is combustion controls.

Good combustion design and operation and constraints on annual operations for maintenance and testing purposes are proposed as CO and VOC BACT for the emergency diesel engines. The emergency diesel engines will be subject to the applicable emission standards of NSPS Subpart IIII for stationary compression ignition internal combustion engines. Subpart IIII limits CO emissions to 3.5 g/kWh for model year 2007 and later emergency generator diesel engines greater than 750 bhp. Subpart IIII limits the combination of NO_x and NMHC emissions to 6.4 g/kWh for model year 2007 or later emergen-

cy generator diesel engines greater than 750 bhp. The Subpart IIII CO and combination NO_x and NMHC emission limits for model year 2009 and later firewater pump diesel engines between 175 and 300 bph are 3.5 and 4.0 g/kWh, respectively. GREC will use emergency diesel engines that comply with the applicable emission standards of NSPS Subpart IIII.

CO and VOC BACT proposed for the GREC emergency diesel engines are summarized as follows:

- Emission Limit—Applicable standards of NSPS Subpart IIII.
- Averaging Period—Per NSPS Subpart IIII.
- Compliance Method—Engine manufacturer certification in accordance with NSPS Subpart IIII.
- Annual Operating Hours—96 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters.

5.7 BACT ANALYSIS FOR PM/PM_{10}

PM is classified by particle size and is defined by the test methods used to measure stack emissions. Filterable PM is measured using EPA Reference Methods 5, 5B, or 17 which capture particles greater than 0.3 micron in size using a filter that is weighed prior to and following the stack test to determine the gain in weight. In Method 5, the filter is located in the sampling train external to the stack and maintained at a temperature of 248°F. A variation of Method 5 is Method 5B, which maintains the filter temperature at 320°F to exclude H_2SO_4 PM. Method 17 places the filter in the stack and therefore collects PM at the prevailing stack temperature. Filterable PM_{10} is measured using either EPA Reference Methods 201 or 201A. Both of these test methods collect filterable PM with a nominal aerodynamic diameter of 10 microns or less using an in-stack cyclone and filter system. All of the filterable PM test methods, commonly referred to as front-half PM, determine the mass of PM that condenses at or above the filter temperature.

EPA also includes condensable PM as a component of PM_{10}. Condensable PM is collected using EPA Reference Method 202 by passing the filtered sample gas stream through a series of chilled water-filled impingers to maintain an impinger outlet sample gas temperature of 68°F or less. Following sampling, the impinger solution is purged with nitrogen and extracted with methylene chloride. The organic and water fractions are then evaporated and the residues weighed to determine the mass of condensable PM. Since the impingers are located in the sampling train downstream of the filter, condensable PM is also referred to as back-half particulate. As discussed in EPA's May 16, 2008, final rule regarding implementation of NSR for $PM_{2.5}$, there are technical issues with the current stack test method for condensable PM. For this reason, EPA is not requiring states to address condensable PM for either PM_{10} or $PM_{2.5}$ in NSR permits until completion of a transition period ending January 1, 2011, to allow for further stack test method research.

In summary, PM includes the filterable portion of PM as measured by EPA Reference Methods 5, 5B, or 17. PM_{10} includes filterable PM less than 10 microns as measured by EPA Reference Methods 201 or 201A and condensable PM as measured by EPA Reference Method 202. Since PM_{10} includes condensable particulate and PM does not, PM emission sources will have higher PM_{10} emissions compared to PM. For biomass-fired combustion sources, PM_{10} emission rates are more than double that of PM emissions. Accordingly, the distinction between PM and PM_{10} is important when assessing BACT for biomass-fired combustion sources.

5.7.1 BFB BOILER

PM/PM_{10} emissions resulting from the combustion of any solid fuel are generally due to the oxidation of ash and sulfur contained in the fuel. Specific PM/PM_{10} emission rates depend on the composition of the fuel (i.e., ash content), boiler design and operation, and emission control equipment. Uncontrolled PM/PM_{10} emissions from biomass-fired boilers include the ash from fuel combustion, unburned carbon resulting from incomplete combustion, and condensable compounds. Biomass-fired BFB boilers achieve a high combustion efficiency resulting in PM/PM_{10} emissions that are primarily comprised of

inorganic ash residues. In the case of a boiler equipped with an SCR and DSI, the loading increases due to the reactions with the sorbent and in the SCR. Additional compounds such as ammonium sulfate and ammonium nitrate are formed.

Ash generated by the combustion of biomass will exit the boiler as either bottom ash or fly ash. Fly ash is entrained in the boiler exhaust gas stream and will be discharged to the atmosphere unless removed by emission control equipment. Bottom ash is the noncombustible slag or residue remaining after the biomass is combusted. Bottom ash is removed mechanically from the boiler and is handled and processed as a solid combustion byproduct.

5.7.1.1 Available PM/PM_{10} Control Technologies

Available technologies used for controlling PM/PM_{10} from biomass-fired boilers include the following:

- Centrifugal collectors.
- Electrostatic precipitators (ESPs).
- Wet electrostatic precipitators (WESPs).
- Fabric filters or baghouses.
- Wet scrubbers.

Centrifugal Collectors

Centrifugal (cyclone) separators are primarily used to recover material from an exhaust stream before the stream is ducted to the principle control device since cyclones are effective in removing only large sized (greater than 10 microns) particles.

Electrostatic Precipitators

ESPs remove particles from a gas stream through the use of electrical forces. Discharge electrodes apply a negative charge to particles passing through a strong electrical field. These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping of the collecting electrodes.

Wet Electrostatic Precipitators

WESPs remove particles from a gas stream using the same mechanisms as described above for ESPs. A WESP, however, removes particles from the collecting electrodes by washing of the collection surface using water, rather than mechanically rapping the collector plates. WESPs are common in applications where the exhaust gas stream has a high moisture content, is below the dew point, or includes particulate that may be difficult to remove from a dry ESP.

Fabric Filter

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM/PM_{10} is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) as the gas passes through the fabric filter. Accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Reverse air pneumatic cleaning isolates a section of the fabric filter and uses a dedicated fan to provide air flow in the opposite direction of normal air flow to remove collected particulate matter. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute-square foot ($cfm\text{-}ft^2$).

Wet Scrubbers

Wet scrubbers remove PM/PM_{10} from gas streams principally by inertial impaction of the particulate onto a water droplet. Particles can be wetted by impingement, diffusion, or condensation mechanisms. To be wetted, PM/PM_{10} must either make contact with a spray droplet or impinge upon a wet surface. In a Venturi scrubber, the gas stream is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high-pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity causing the water to shear into droplets. Particles in the gas stream then impact onto the water droplets pro-

duced. The entrained water droplets are subsequently removed from the gas stream by a cyclone separator. Venturi scrubber collection efficiency increases with increasing pressure drops for a given particle size. Collection efficiency will also increase with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Packed-bed and venturi scrubber collection efficiencies are typically 90 percent for particles smaller than 2.5 microns in size.

5.7.1.2 Technical Feasibility and Ranking

All of the available PM/PM_{10} control technologies described previously are technically feasible for the biomass-fired BFB boiler. Table 5-9 provides a summary of the technical feasibility and ranking of the available PM/PM_{10} control technologies. As shown, fabric filter technology provides the highest control efficiency.

5.7.1.3 Evaluation of Control Technologies

GREC LLC proposes to install the PM/PM_{10} control technology identified as having the highest control efficiency—fabric filter. The economic and energy impacts associated with the installation and operation of this control technology is considered reasonable. There are also no significant collateral environmental issues that would justify rejection of this control technology as BACT.

5.7.1.4 Proposed PM/PM_{10} BACT

Table 5-10 provides a summary of biomass-fired utility and industrial size boiler (greater than 250 MMBtu/hr) PM/PM_{10} BACT determinations for the past 5 years.

GREC LLC proposes a PM/PM_{10} BACT emission rate of 0.015 lb/MMBtu (filterable). This limit reflects the expected performance of the fabric filter. PM/PM_{10} BACT emission limits proposed for the GREC BFB boiler are summarized as follows:

- Emission Limits—0.015 lb/MMBtu (filterable PM/PM_{10}).
- Averaging Period—Stack test duration.
- Compliance Method—EPA Reference Methods 201 or 201A.

Table 5-9. Ranking of Available PM/PM_{10} Control Technologies—BFB Boiler

Control Technology	Technically Feasible (Yes/No)	Control Efficiency* (%)
Fabric filter	Yes	99.5
ESP	Yes	99
WESP	Yes	99
Wet Venturi scrubber	Yes	95
Cyclone collector	Yes	80 to 90

*Control efficiencies vary depending on the level of uncontrolled PM/PM_{10} emissions.

Source: ECT, 2009.

Table 5-10. Summary of Biomass-Fired Boiler PM/PM10 BACT Determinations (Page 1 of 2)

RBLC ID	Facility Name	Permit Dates: Issuance	Permit Dates: Update	Process Description	Fuel	Throughput	Control Description	Emission Limit	Basis
PM									
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass Boiler 2			Good combustion practices	0.01 lb/MMBtu	BACT-PSD
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass Boiler 1	Natural gas	308 MMBtu/hr	Cyclone and ESP	0.03 lb/MMBtu	BACT-PSD
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass Boiler 3			Cyclone and ESP	0.037 lb/MMBtu	BACT-PSD
ND-0022	Northern Sun	05/01/06	02/13/07	Wood/hull fired boiler	Biomass		ESP	0.08 lb/MMBtu	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Peanut hull unloading	Wood	3 tph		0.6 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Final grind hammermill processing	Wood	52 tph	Baghouse	1 lb/hr	Other Case-by-Case
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Wood thermal oxidizers for wood pellet process	Wood/wood paste	43 MMBtu/hr	Setting chamber and cyclone	3.9 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Heat energy systems for pellet processing	Wood/woodpaste	77 MMBtu/hr	Setting chambers and cyclones	6.9 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Pellet mills processing	Wood	51 tpy	Cyclones	10.2 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Raw material unloading	Wood/wood paste	121 tph		12.1 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Rotary and fuel dryer processing	Wood	65.6 tph	Setting chambers and cyclones CEMS	13.1 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Primary grind hammermills	Wood	121 tph	Setting chambers and cyclones and CEMS	14.5 lb/hr	BACT-PSD
WA-0329	Darrington Energy Cogeneration Power Plant	02/11/05	07/05/06	Cooling tower			Installation of drift eliminators with drift loss of less than 0.001 percent of the recirculating water flow rate.		BACT-PSD
PM_{10}									
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Planer mill bag house		48,000 dscf/min	Bag house	0.005 g/dscf	BACT-PSD
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass boiler 4			Good combustion practice	0.01 lb/MMBtu	BACT-PSD
WA-0335	Simpson Tacoma Kraft Company, LLC	05/22/07	08/21/07	Utility and large industrial sized boilers/furnaces	Wood waste	595 MMBtu/hr	Existing ESP	0.02 lb/MMBtu	BACT-PSD
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Wood-fired cogeneration unit	Bark and waste wood	430 MMBtu/hr	ESP	0.02 lb/MMBtu	BACT-PSD
WA-0329	Darrington Energy Cogeneration Power Plant	02/11/05	07/05/06	Wood waste-fired boiler	Wood waste	403 MMBtu/hr	Dry ESP	0.02 lb/MMBtu	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Peanut hull unloading	Wood	3 tph		0.6 lb/hr	BACT-PSD

Table 5-10. Summary of Biomass-Fired Boiler PM/PM10 BACT Determinations (Page 2 of 2)

RBLC ID	Facility Name	Permit Dates		Process Description	Fuel	Throughput	Control Description	Emission Limit	Basis
		Issuance	Update						
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Final grind hammermill processing	Wood	52 tph	Baghouse	1 lb/hr	Other Case-by-Case
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Wood thermal oxidizers for wood pellet process	Wood/wood paste	43 MMBtu/hr	Setting chamber and cyclones	3.4 lb/hr	BACT-PSD
OH-0307	South Point Biomass Generation	04/04/06	08/16/07	Wood fired boilers (7)	Wood	318 MMBtu/hr	Pulse jet baghouse	3.97 lb/hr	BACT-PSD
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Dry kilns		300 MM board f/yr		4 tpy	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Heat energy systems for pellet processing	Wood/woodpaste	77 MMBtu/hr	Setting chambers and cyclones	6.2 lb/hr	BACT-PSD
OH-0307	South Point Biomass Generation	04/04/06	08/16/07	Wood handling system			Baghouse, one at each transfer point	6.71 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Pellet mills processing	Wood	51 tpy	Cyclones	10.2 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Raw material unloading	Wood/wood paste	121 tph		12.1 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Rotary and fuel dryer processing	Wood	65.6 tph	Setting chambers and cyclones and CEMS	13.1 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Primary grind hammermills	Wood	121 tph	Setting chambers and cyclones CEMS	14.5 lb/hr	BACT-PSD
WA-0336	Grays Harbor Paper LP	11/17/06	08/21/07	Utility-and large industrial sized boilers	Wood waste	379 MMBtu/hr	Multiclones with 80 14-inch diameter tubes. Two parallel impringement wet scrubber with six top and six bottom showers	52.5 lb/hr	BACT-PSD
WA-0336	Grays Harbor Paper LP	11/17/06	08/21/07	Industrial-size boilers/furnaces 100 to 250 MMBtu/hr	Wood waste	227 MMBtu/hr	Multiclones - western precipitation type 9 vg, size 189-7 Secondary multiclones - 9 14-inch tubes Secondary scrubber packed, wet Venturi	78.4 lb/hr	BACT-PSD
LA-0188	Bogalusa Mill	11/23/04	06/02/06	No. 12 hogged fuel boiler	Bark	787.5 MMBtu/hr	Existing wet scrubber	121.93 lb/hr	BACT-PSD

Source: ECT, 2009.

Table 5-11 provides a summary of the preliminary fabric filter design criteria.

5.7.2 EMERGENCY DIESEL ENGINES

As previously noted, the emergency diesel engines will be fired with ULSD fuel oil and will each operate no more than 96 hr/yr for routine testing and maintenance purposes. Potential PM/PM_{10} emission rates are for the emergency generator and firewater pump diesel engines are 0.06 and 0.02 tpy, respectively.

The emergency diesel engines will be subject to the applicable emission standards of NSPS Subpart IIII for new nonroad ICEs. Subpart IIII limits PM emissions to 0.2 g/kWh for a 2007 model year or later emergency generator diesel engines with an output greater than 750 bhp. For 2009 and later model year emergency firewater pump diesel engines between 175 and 300 bph, the Subpart IIII PM emission limit is also 0.2 g/kWh. Both of the emergency diesel engines purchased for GREC will comply with the applicable emission standards of NSPS Subpart IIII.

Compliance with the stringent NSPS Subpart IIII emission standards and limited annual operating hours for maintenance and testing purposes is proposed as PM/PM_{10} BACT for the GREC emergency generator and firewater pump diesel engines. PM/PM_{10} BACT proposed for the GREC emergency diesel engines is summarized as follows:

- Emission Limit—Applicable standards of NSPS Subpart IIII.
- Averaging Period—Per NSPS Subpart IIII.
- Compliance Method—Engine manufacturer certification in accordance with NSPS Subpart IIII.
- Annual Operating Hours—96 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters.

Table 5-11. Preliminary Fabric Filter Design Criteria

Parameter	Unit	Estimated Design Value	Notes
Flue gas flow rate to fabric filter	acfm	720,000	Flue gas flow to the fabric filter is based upon the design wood mix
Inlet gas temperature	°F	465 to 550	
Inlet filterable particulate loading	lb/hr	1,850 (1.36 lb/MMBtu)	Based on design wood mix ash content of 0.98 percent and heating value of 8,529 Btu/lb HHV, dry basis and sorbent
Outlet filterable particulate loading	lb/MMBtu	0.015	Based on maximum heat input of 1,358 MMBtu/hr
	lb/hr	20.4	
Bag material	—	—	To be determined during detailed design
Bag diameter, length, number of bags	—	—	To be determined during detailed design
Number of modules and compartments per module	—	—	To be determined during detailed design
Air to cloth ratio	—	Approximately 4	Final air-to-cloth ratio will be determined during detailed design
Pressure drop across baghouse	inches of water	6 to 8	
Cleaning mechanism and cycle	—	Pulse Jet	

Source: GREC, 2009.

5.7.3 COOLING TOWER

5.7.3.1 Cooling Tower

GREC will include a four-cell mechanical draft cooling tower that will emit PM/PM_{10}. Because of direct contact between the cooling water and ambient air, a small portion of the recirculating cooling water is entrained in the air stream and discharged from the cooling tower as drift droplets. These water droplets contain the same concentration of dissolved solids as found in the recirculating cooling water. Large water droplets quickly settle out of the cooling tower exhaust stream and deposit near the tower. The remaining smaller water droplets may evaporate prior to being deposited in the area surrounding the cooling tower. These evaporated droplets represent potential PM/PM_{10} emissions because of the fine PM/PM_{10} formed by crystallization of the dissolved solids contained in the droplet.

5.7.3.2 Available PM/PM_{10} Control Technologies

The only feasible technology for controlling PM/PM_{10} from wet cooling towers is the use of drift eliminators. Drift eliminators rely on inertial separation caused by airflow direction changes to remove water droplets from the air stream leaving the tower. The water droplets are returned to the cooling tower. Drift eliminator configurations include herringbone (blade-type), wave-form, and cellular (honeycomb) designs. Drift eliminator materials of construction include ceramics; fiber-reinforced cement; metal; plastic; and wood fabricated into closely spaced slats, sheets, honeycomb assemblies, or tiles.

5.7.3.3 Proposed PM/PM_{10} BACT

PM/PM_{10} emissions from the GREC cooling tower will be controlled using high-efficiency drift eliminators. The cooling tower will achieve a drift loss rate of no more than 0.0005 percent of the cooling tower recirculating water flow. This cooling tower drift loss rate is consistent with recent FDEP BACT determinations. PM/PM_{10} BACT proposed for the GREC cooling tower is summarized as follows:

- Emission Limit—Use of high-efficiency drift eliminators with a drift loss rate of no more than 0.0005 percent.
- Compliance Method—Cooling tower manufacturer certification.

5.7.4 BIOMASS FUEL PROCESSING

The disc screens and hammer hogs will be located within the biomass fuel processing building. This building will be equipped with local exhaust ventilation systems that will be routed to a fabric filter for control of PM/PM_{10} emissions.

5.7.5 MATERIAL HANDLING AND STORAGE

GREC will include biomass fuel, fly ash, and DSI sorbent receiving, processing, handling, and storage systems. These material handling and storage processes will generate fugitive and point (stack) source PM/PM_{10} emissions. Fugitive emissions are emissions that cannot reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. In contrast, point source emissions are emissions that can reasonably be collected and subsequently passed through a stack, chimney, vent, or other functionally equivalent opening. Fugitive and point source PM/PM_{10} emissions from material handling and storage will be generated from three general source categories: transfer points, storage silos and piles, and truck traffic on facility roadways.

5.7.5.1 Available PM/PM_{10} Control Technologies

Transfer Points

Transfer points include material loading/unloading, conveyor-to-conveyor drops, material transfers from reclaim hoppers to conveyors, and transfers from conveyors to storage silos. Particulate emissions will be generated as material drops through the transfer point. The potential to generate particulate emissions at a transfer point is a function of the rate at which the material flows through the transfer point, exposure to wind, and the material's particle size and moisture content. Potential emissions from a transfer point can be reduced by decreasing the speed at which the material is transferred, decreasing the wind speed to which the material is exposed, or increasing the aggregate's moisture content by watering or chemical wetting agents. Transfer point emissions may be further reduced by enclosing the transfer operations within a structure, and exhausting the air from the structure through a particulate control device (e.g., fabric filter).

Storage Silos and Piles

The transfer of materials (i.e., biomass fuel, fly ash, and sorbent) to storage silos results in point source PM/PM_{10} emissions due to the displacement of air from the silos. Fabric filters (also referred to as bin vent filters) are commonly used to control PM/PM_{10} emissions from storage silos.

Fugitive PM/PM_{10} emissions associated with the biomass fuel storage piles include dust emissions produced by adding/removing material from the pile, routine shaping of the pile and from wind erosion. A combination of material drop controls (e.g., telescopic chutes), compaction, and dust suppression sprays (e.g., wetting) can be used to minimize fugitive emission from the biomass fuel storage piles.

Facility Roadways

Vehicular traffic on paved roads will generate fugitive PM/PM_{10} emissions. Particulate emissions from roads can be controlled by sweeping, applying water as necessary, and limiting vehicle speeds.

5.7.5.2 Proposed PM/PM_{10} BACT

A combination of good operating practices and fabric filters are proposed as PM/PM_{10} BACT for the GREC material handling emission sources. Specific PM/PM_{10} control measures proposed for the GREC material handling systems are as follows:

- Transfers Points—To the extent practical and appropriate, material handling transfer points will be enclosed. Where complete enclosure is not practical, partial enclosure and/or wet dust suppression systems using water sprays or a chemical wetting agent will be employed. Opacity from each transfer point will not exceed 5 percent.
- Storage Silos—Silos storing dry materials will be equipped with bin vent filters with a design outlet PM/PM_{10} concentration of no more than 0.015 gr/dscf.
- Storage Piles—Water or chemical dust suppression will be applied to the biomass fuel storage piles, as necessary.

- Roads—All plant roadways will be paved. These roads will be watered or swept, as necessary, to control fugitive PM/PM_{10} emissions.

5.8 SUMMARY OF PROPOSED BACT

Table 5-12 provides a summary of the BACT proposed for GREC including the emission limit, averaging period, and compliance method.

Table 5-12. Summary of Proposed BACT

Emission Unit	Pollutant	Averaging Period	BACT Emission Limit	Compliance Method
BFB boiler	NO_x	30-day rolling	0.070 lb/MMBtu	CEMS
	SO_2	30-day rolling	0.041 lb/MMBtu	CEMS
	CO	30-day rolling	0.120 lb/MMBtu	CEMS
	VOC (as CH_4)	Stack test duration	0.013 lb/MMBtu	EPA Reference Methods 18, 25, 25A
	PM/PM_{10} (filterable)	Stack test duration	0.015 lb/MMBtu	EPA Reference Methods 201/201A
Emergency diesel engines	NO_x	N/A	Applicable NSPS Subpart IIII standard	Engine manufacturer certification
	SO_2	N/A	ULSD fuel oil	Fuel oil supplier certifications
	CO	N/A	Applicable NSPS Subpart IIII standard	Engine manufacturer certification
	VOC (as CH_4)	N/A	Applicable NSPS Subpart IIII standard	Engine manufacturer certification
	PM/PM_{10}	N/A	Applicable NSPS Subpart IIII standard	Engine manufacturer certification
Cooling tower	PM/PM_{10}	N/A	Drift eliminators Drift Loss Rate of 0.0005 percent	Cooling tower manufacturer certification

Table 5-12. Summary of Proposed BACT (Continued, Page 2 of 2)

Emission Unit	Pollutant	Averaging Period	BACT Emission Limit	Compliance Method
Biomass fuel processing				
	PM/PM_{10}	N/A	Baghouse: 5-percent opacity	EPA Reference Method 9
Material handling sources				
Transfer points	PM/PM_{10}	N/A	Enclosure, partial enclosure, wet suppression, application of chemical wetting agents	Good operating practices
			Baghouses/bin vents 5-percent opacity	EPA Reference Method 9
Storage silos (dry materials)	PM/PM_{10}	N/A	Baghouses/bin vents 5-percent opacity	EPA Reference Method 9
Storage piles	PM/PM_{10}	N/A	Wet suppression, application of chemical wetting agents	Good operating practices
Plant roads	PM/PM_{10}	N/A	Paving of primary roadways, watering and/or sweeping	Good operating practices

Sources: GREC, 2009.
ECT, 2009