TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Northwest Florida Renewable Energy Center, LLC

47-Megawatt (net) Biomass Integrated Gasification Combined Cycle

Gulf County

DEP File No. 0450012-001-AC

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Special Projects Section

January 27, 2010

1. APPLICATION INFORMATION

1.1. Applicant Name and Address

Northwest Florida Renewable Energy Center, LLC
11993 South Street, Route 63
Clinton, Indiana 47842

***Authorized Representative*:** Mr. Kenn Davis, Manager

1.2. Processing Schedule

September 2, 2009:	Received air construction permit application from North West Florida Renewable Energy Center, LLC.
October 2, 2009:	Sent request for additional information (RAI) to the Applicant.
October 14, 2009:	Held public meeting regarding application.
November 4, 2009:	Received response to RAI.
January 27, 2010:	Intent to Issue PSD Permit distributed.

1.3. Facility Location

The proposed Northwest Florida Renewable Energy Center (NWFREC) will be located in Port St. Joe, Gulf County, Florida. The proposed project location is approximately 1.6 miles directly north of the intersection of US Highway 98 and Highway 71, off of Industrial Road at 521 Premier Drive in Port St. Joe, Gulf County. The approximate UTM coordinates for this site are Zone 16; 664.16 kilometers (km) East and 3,301.96 km North. The location of the proposed NWFREC is shown in Figure 1.

Figure 1. Project Location in Port St. Joe.

Figure 2. Artist Rendition of Future NWFREC.

Figure 2 is an artist rendition of the proposed facility. Initially biomass will be delivered by trucks and not by railroad. The site is located approximately 75 km from the nearest boundary of the St. Marks National Wildlife Refuge and also 75 km from the nearest boundary of the Bradwell Bay National Wilderness Area; the nearest Federal Prevention of Significant Deterioration (PSD) Class I Areas.

1.4. Regulatory Categories

Standards of Performance for New Stationary Sources

The proposed project is subject to:

- 40 CFR 60, Subpart A—General Provisions.
- 40 CFR 60, Subpart Dc – NSPS Requirements for Small Industrial Commercial-Institutional Steam Generating Units.
- 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines.

National Emissions Standards for Hazardous Air Pollutants (NESHAP)

The facility is not a major source of hazardous air pollutants (HAP) because it will not have the potential to emit (PTE) 10 tons per year (TPY) of any single HAP or 25 TPY of all HAP.

Title IV, Acid Rain Provisions

The facility will be subject to the Acid Rain provisions of the Clean Air Act.

Title V, Permits

The facility is a Title V or "Major Source" of air pollution because the potential emissions of at least one regulated pollutant will exceed 100 tons per year (TPY). Key regulated pollutants include carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2) and volatile organic compounds (VOC).

Clean Air Interstate Rule (CAIR)

The facility is subject to CAIR in accordance with the Final Department Rules in Rule 62-296.470, F.A.C.

Prevention of Significant Deterioration (PSD)

The facility is not classified as a "Major Stationary Source" because it will not have the potential to emit (PTE) 250 TPY or more of a PSD pollutant and is not one of the facility categories with the PSD applicability threshold of 100 TPY as described in Section 62-210.200, Florida Administrative Code (F.A.C.).

Siting

The facility is not subject to certification pursuant to the power plant siting provisions of Chapter 62-17, F.A.C. because it will produce less than 75 megawatts (MW) of power.

2. PROPOSED PROJECT SUMMARY

2.1. Project Description

The applicant proposes to construct a nominal 47 MW (net) biomass integrated gasification combined cycle (BIGCC) unit and auxiliary equipment. The BIGCC unit will consist of: a biomass gasification system that yields biomass product gas (BPG); two BPG-fueled SOLAR T-130 combustion turbine-electrical generators (CTG); two supplementary-fired heat recovery steam generators (HRSG) equipped with duct burners (DB); a steam turbine-electrical generator (STG); CTG/HRSG and char combustor exhaust stacks; and two flares.

Additional equipment will be included to accomplish:

- Biomass storage, handling, drying and feeding;
- BPG cooling and heat recovery;

- Char separation and combustion (with tars);
- BPG particulate and tar removal;
- Ash and tar handling;
- BPG scrubbing;
- BPG compression;
- Catalytic destruction of pollutants from the CTG; and,
- Cooling of steam turbine condensate and compressor gas.

2.2. Additional Project Features

Fuel

Municipal Solid Waste (MSW) is prohibited as a fuel at this facility. The NWFREC will generate electricity from BPG, char and tar derived on-site from woody biomass. Natural gas, biodiesel or ultralow sulfur distillate fuel oil (ULSD FO) will be used primarily as a startup fuel.

Generating Capacity

The BIGCC will have a nominal electrical generating capacity of 47 MW (net), 58.2 MW (gross).

Air Pollution Controls – Char/Tar Combustor

- SO_2 will be limited by use of woody biomass that is low in sulfur compared with typical fossil fuels. Gasified sulfur gases will tend to follow the BPG stream and not the char.
- PM/PM_{10} will be reduced by combustion in an oxidizing atmosphere followed by cyclones and filtration in a fabric filter (FF) baghouse.
- Carbon monoxide (CO) and volatile organic compounds (VOC) emissions are limited by sufficiently high temperature combustion.
- NO_X formation is limited by combustion in a circulating fluidized bed (CFB) of olivine (sand) at temperatures less than those characteristic of thermal NO_X formation.
- Dioxin and furan (D/F) formation potential is limited by relatively low chloride in woody biomass and sufficient residence time at destructive temperatures.
- Mercury (Hg) is inherently low in the woody biomass compared with typical fossil fuels or wastes.
- It is estimated that the char will contain approximately 14,500 British thermal units (Btu) per pounds (lb). The heat input from the char combustor to the system will be approximately 153 million Btu per hour (mmBtu/hr) or about 25 percent of the total heat input.

Air Pollution Controls – BPG Combustion in CTG and DB

- SO_2 is limited by use of woody biomass that is low in sulfur compared with typical fossil fuels and also by removal of hydrogen sulfide (H_2S) through caustic scrubbing as described below.
- PM/PM_{10} will be removed from the BPG by the gasifier cyclones, coarse and fine solids removal systems and high temperature combustion in the CTG and DB.
- NO_X formation is limited by: minimal atmospheric nitrogen (N_2) available for thermal NO_X formation; removal of nitrogen compounds such as ammonia (NH_3) in the water scrubber prior to combustion; water injection into the combustors; and by selective catalytic reduction

(SCR) in the HRSG following combustion.

- HCl is also removed in the scrubber water.
- CO and VOC will be controlled by high temperature combustion and an oxidation catalyst system.
- D/F is limited by: relatively low chloride in woody biomass; removal of tar from BPG; scrubbing of gaseous chlorides prior to combustion in the CTG; and further oxidation by SCR in the HRSG after combustion in the CTG and DB.
- Each HRSG will have a combined cycle stack with a nominal diameter of 78 inches. The following table summarizes the exhaust characteristics of each of the two CTG/HRSG sets, inclusive of the DB and while firing BPG:

Table 1. Exhaust Characteristics of each HRSG (CTG/DB) at 100% Load and 59 °F.

BPG Heat Input Rate to CTG, DB Lower Heating Value (LHV)		Compressor Inlet Temp., °F	Stack Exhaust Temp., °F	Stack Exhaust Flow lb per hour (lb/hr)
CTG	161 mmBtu/hr	59 °F		
DB	71.2 mmBtu/hr			
Total	232.2 mmBtu/hr		352°F	421,390

3. PROCESS DESCRIPTION

3.1. Principle

Integrated gasification and combined cycle (IGCC) involves the incomplete combustion of fuel or residues in a reducing atmosphere and then combustion of the resultant product gas in an oxidizing atmosphere with associated heat recovery, chemical production, steam generation, and electrical power production.

The term "integrated" relates to varying degrees of interchange of air, steam, condensate, feed water, fuel, electricity, etc. between the key gasification step, the combustor and the combined cycle (CTG/HRSG/STG). "Integration means recovery of the waste energy available, improvement of the efficiency and, where possible, reduction of the investment cost."[1] BIGCC as described for this project includes and integrates the char combustion step.

3.2. Fuel Slate and Sources

The feedstock will consist of clean woody biomass that will be processed at a remote fuel preparation area (or areas) where it will be sorted, screened and chipped to size. NWFREC has identified the possible, available feedstock types listed in Table 2 for their facility. Materials not on the list cannot be used as fuel without prior approval of the Department.

Woody biomass consists of cellulose, hemicellulose, lignin and minerals. NWFREC submitted fuel analyses for biomass of the kind they intend to use at their energy center facility. The key values are given in Table 3. The actual fuels approved for use are identified in the Best Management Practices (BMP) Plan included in the appendices to the draft permit. A similar analysis for a typical Eastern Kentucky (E. KY) bituminous coal is presented for comparison.

Table 2. Summary of Woody Biomass Fuel Descriptions.

Fuel Group	Description
Saw Dust	Saw dust and kerf waste from cutting/milling whole green trees
Hogged Fuel	Land clearing debris that has either been processed, run to a tub grinder, or a horizontal mill at a specific private forest clearing site.
Processed Butt Cuts	Round wood residues that are either of oversized or undersized non processible untreated materials from post or pole manufacturers.
Fuel (vegetative) Crop	A vegetative product specifically grown for energy use or a waste product of agricultural operations (e.g., corn stover, peanut hulls, etc.)

Table 3. Analyses of Candidate Biomass Feedstock Compared with Bituminous Coal.

Parameter	Saw Dust	GP Fuel [1]	Hogged Fuel	Butt Cuts	Crop Fuels	E. KY Coal
Proximate Analysis (dry)						
Moisture (%)	59.68	36.14	34.54	31.52	23.35	2.38
Ash (%)	3.12	1.80	1.67	0.48	3.80	12.27
Calorific Value (Btu/lb)	8,458	9,061	8,254	8,336	8,070	12,900
Volatile Matter (%)	78.15	75.15	79.37	83.25	75.75	35.79
Fixed Carbon (%)	18.73	23.05	18.96	16.27	20.34	51.94
Ultimate Analysis (dry)						
Sulfur (%)	0.02	0.06	0.03	0.01	0.11	1.52
Carbon (%)	50.11	55.38	47.20	51.65	47.37	73.17
Hydrogen (%)	6.01	6.51	5.56	6.10	5.73	5.01
Nitrogen (%)	0.26	0.27	0.34	0.19	0.44	1.62
Oxygen (%)	40.48	35.98	45.20	41.57	42.50	6.41
Fluorine (ppmw)	<10	<10	<10	<10	---	30
Chlorine (%)	0.02	0.02	0.02	0.03	0.00	0.10
Mercury (ppmw)	<0.02	<0.02	0.03	<0.02	---	0.15

1. Georgia Pacific (GP) Fuel is reject material from round wood debarking at an oriented strand board plant.

In general, the key differences between the biomass examples and E. KY coal are:

- Biomass contains more moisture, volatile matter and oxygen (O_2);
- Biomass contains much less carbon and has much less calorific value even on a dry basis; and
- Biomass contains less sulfur, fluorine, chlorine, N_2 and Hg.

3.3. Fuel Receiving and Handling

Biomass Stackout

All woody biomass will be delivered to the site via truck at a rate of approximately 45 trucks per day. The fuel storage pile will contain 10 to 14 days of fuel storage.

The truck receiving system will be equipped with two 75-foot platforms dumping into two 5,000-cubic foot receiving hoppers. The hoppers will have a very slow moving chain drag to minimize dust. The hoppers will have a discharge rate capability of 150 tons per hour (TPH).

Tramp metal will be removed using a suspended self-cleaning magnet from the material stream prior to stockpiling the fuel. From the bottom of the two collection hoppers, the wood chips will be discharged onto a take-away belt conveyor. Material will discharge from the take-away conveyor into a horizontal scalping screen. Any oversized materials will be directed to a vertical hammer hog designed to produce 2-inch minus material.

The hog and ancillary conveyors will be supported in a common tower with applicable chute work and dust collection with baghouse. Material will discharge from the hog onto a covered collection conveyor and then transition to the circular stacker.

The circular stacker will form a circular kidney shaped pile at a rate of 300 TPH. The collection conveyor will deliver material to a fully automated stockpile. The stacker will be capable of automatically building a circular stockpile. The feedstock will be evenly distributed in piles up to an average of 40 feet high. The stockpile will have a storage capacity of 2 million cubic feet. The stacker reclaimer will include on-board controls and the stacker reclaimer will be designed to meet operational and structural specifications.

The main storage pile will be built and managed to the extent feasible on the principle of first-in/first-out. A similar configuration is shown in Figure 3.

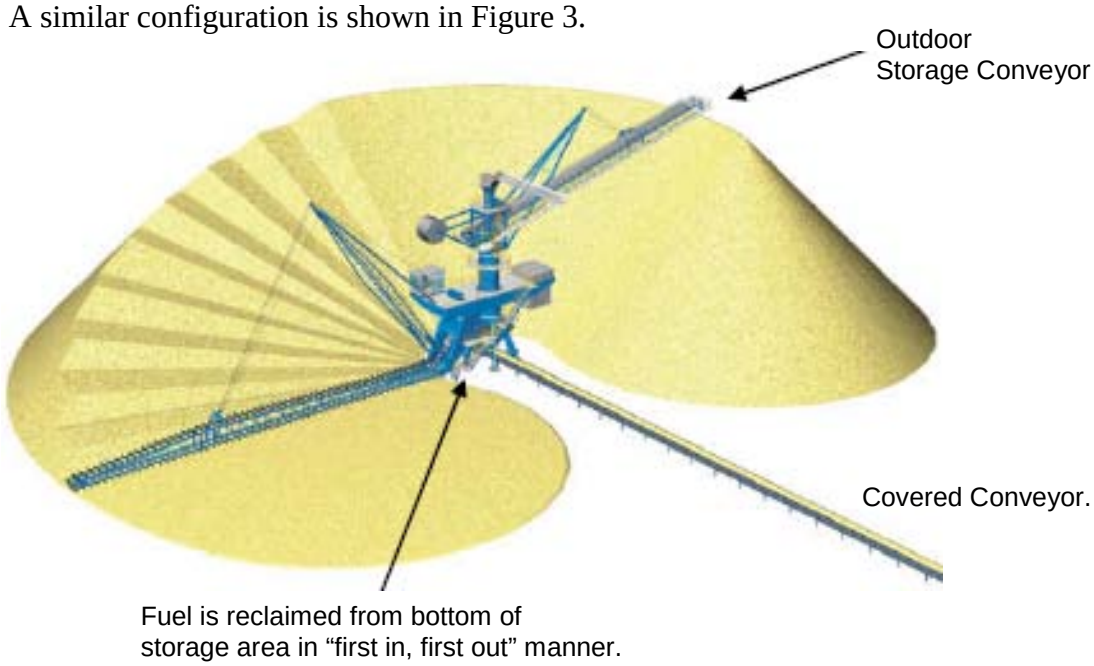

Figure 3. Layout of Kidney-Shaped Pile Operating on Principle of First In/First Out.

The purpose is to allow good chip blending, high stacking and reclaiming, low chip damage, and low operation costs. Such piles are fairly resistant to high winds. By practicing first-in/first-out, such operation will minimize dust generation, biological degradation and odors.

Biomass Reclaim

Biomass will be reclaimed via a stacker from the storage pile via a drag chain to covered Reclaim Conveyor No. 1. This conveyor will transfer the material to covered Reclaim Conveyor No. 2 and from Reclaim Conveyor No. 2 the biomass will be transported to Supply Conveyor No. 3, which is controlled by a baghouse.

Prior to entering the powerhouse the fuel will be conveyed via Supply Conveyor No. 3 to a dryer where the moisture is reduced from as high as 45 percent (%) to approximately 23% by contact with preheated air, as shown in Figure 4 below.

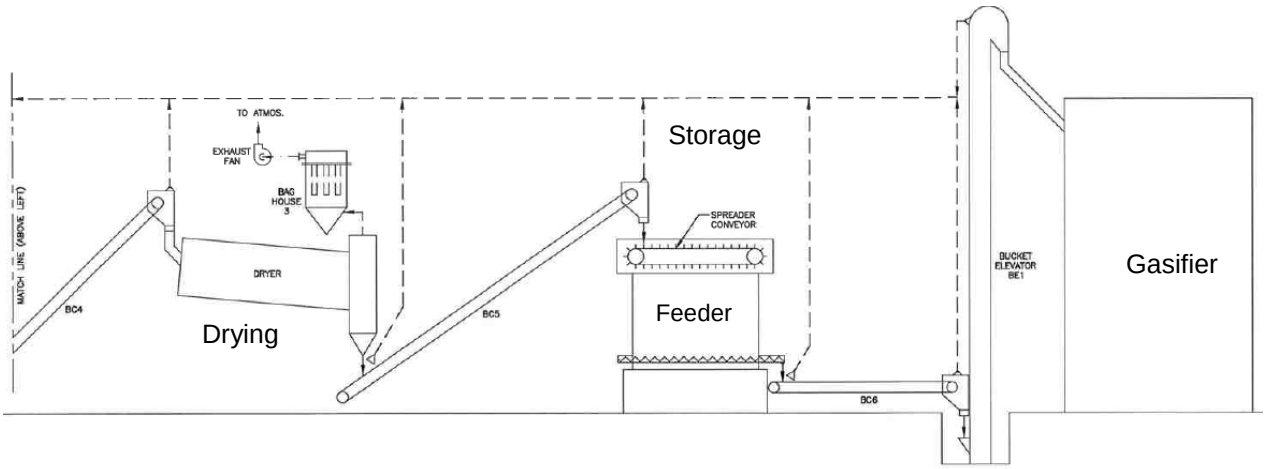

Figure 4. Woody Biomass Drying, Conveyance and Feeding to Gasifier.

The moist air leaving the system will be filtered through a baghouse and exhausted to the ambient air. The lower moisture biomass will be conveyed from the dryer via a covered conveyor system to the gasification process area where it is stored in a metering/storage bin. Approximately 900 dry tons per day (TPD) of biomass (maximum 1,000 dry TPD) will be fed to the gasifier.

All transfer systems from conveyor to conveyor employ head boxes, chutes, and skirtboard systems enclosed to the degree practicable to contain the fuel and any dust that may be produced at the transfer points. Particulate emissions from these transfer points are kept to a minimum through special designs. The feed bin has a bin vent on top of it to filter the air displaced by transfer of wood into the metering bin.

In addition, all conveyors will be covered to reduce particulate matter emissions. A baghouse will control emissions from the day bin and from transfer of material from the day bin to the bucket elevator.

3.4. Gasifier/Combustor

This project is the first relatively large commercial application of a low pressure gasifier in a woody biomass-fed IGCC process or BIGCC. The SilvaGas gasification system consists of two sections; a gasifier into which the biomass is fed and a char combustor in which the char and tar are combusted to provide heat to the gasifier and the woody biomass dryer.

For reference, the gasifier/combustor arrangement shown in Figure 5 was invented by Battelle Laboratories and is called "SilvaGas". Batelle operated a pilot scale unit between 1980 and 2000 coupled to a very small (0.2 MW) CTG.

Unlike other gasification processes, SilvaGas is not based on starved combustion (partial oxidation) whereby *some* oxygen (O_2) is supplied in nearly pure form (O_2-blown) or as air (air-blown). Instead, the biomass is subjected to steam and rapidly converted (pyrolized) to BPG in the absence of oxygen within a CFB of sand.

The heat for pyrolysis is derived from other parts of the process; most notably char combustion as described below, and low pressure steam from the STG. The hot sand imparts heat to the biomass and supports gasification. The steam serves as the gasification medium and participates in the pyrolysis reactions.

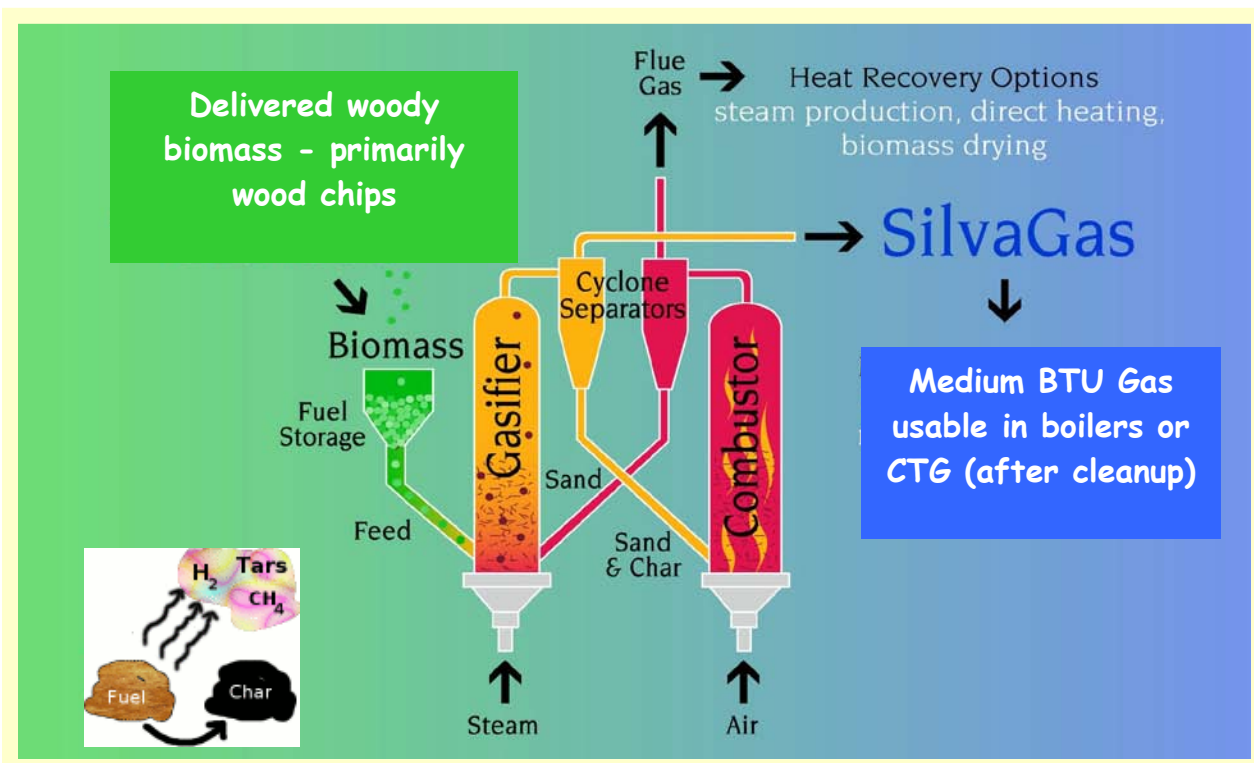

Figure 5. Gasifier/Combustor Section of the SilvaGas Process and Exhaust streams.

During the process, the sand cools and the biomass feed breaks down to produce BPG, char (nearly pure carbon), ash and condensable organic compounds referred to as "tar". The gasification proceeds as follows:

Equation 1: The primary products from the gasifier section are:

$$C_aH_bN_cO_dS_eX_f + H_2O + \text{hot sand} \rightarrow CO, H_2, CH_4, N_2, NH_3, H_2S, HCl, \text{char}, \text{tar}, \text{ash}, \text{cooled sand}$$

The subscripts (a, b, etc.) on the left are variable depending on the type of fuel. "X" represents miscellaneous species. The proposed gasification process operates at a relatively low temperature (~ 1400 °F) and pressure (near atmospheric) compared with higher temperature, high pressure air-blown or pure O_2-blown coal gasification processes.

Within the extreme reducing conditions in the gasifier, most fuel-nitrogen is converted to NH_3. The NH_3 concentration in the exit BPG depends on the time-temperature history of the gas in the gasifier. [2] Longer residence time at high temperature (~1,850 °F or greater) would favor removal of NH_3 by:

Equation 2. Thermal decomposition of NH_3 is described by the following global equation:

$$2NH_3 + heat \leftrightarrow N_2 + 3H_2$$

The relatively low operating temperature of the gasifier vessel (closer to 1,400 than 1,850 °F) results in less NH_3 decomposition in the SilvaGas process compared with higher temperature gasifiers, other factors being equal. However, the low N_2 content of the gas (due to lack of atmospheric nitrogen) would favor the forward reaction. Unless scrubbed, NH_3 reaching the CTG and DB is converted to NO_X.

The BPG (also containing the uncondensed tars) emanating from the gasifier is subsequently cleaned as described below and is ultimately burned in the CTG and DB. The char and cooled sand are separated from the BPG exiting the gasifier in dual, two-stage gasifier cyclones. The sand, char and tars (returned from downstream BPG cleaning) are then fed to the combustor. Air is introduced at the bottom of the vessel and supports conventional combustion of the char and tars in a CFB of sand and an oxidizing atmosphere at approximately 1615 °F.

Equation 3: The primary products from the combustor section (oxidizing atmosphere) are:

$$C_aX_b\ (char) + C_aH_bO_c\ (tar) + O_2\ (air) + cool\ sand \rightarrow CO_2,\ CO,\ NO_X,\ N_2,\ H_2O,\ char,\ ash,\ hot\ sand$$

Most sand and unburned char is captured in the cyclones and returned to the gasifier. Make up sand must be added to the process at an estimated rate of 300 lb per day (lb/day). The ash is a waste product that will be continuously removed and disposed off-site in accordance with applicable regulations.

The gasifier/combustor technology was purchased and then commercially demonstrated by Future Energy Research Company (FERCO) at the wood-fueled Burlington Electric Department (BED) Joseph C. McNeil Generating Station in Burlington, Vermont (McNeil Station). FERCO is the predecessor of Biomass Gas & Electric (an affiliate of NWFREC, LLC).

At the McNeil Station, the BPG from the 200 TPD demonstration project augmented the wood fuel burned in an existing conventional boiler at the plant. A magazine article description of the program at McNeil Station is available at:

www.memagazine.org/backissues/membersonly/dec01/features/preaching/preaching.html

The photographs and the gasifier/combustor diagram shown in Figure 6 were taken from the article.

Figure 6. External Views and Internal Diagram of Gasifier/Combustor at McNeil Station.

A technical report describing the design, engineering, construction and startup at McNeil Station was prepared in 1998 by FERCO, BED, the Department of Energy National Renewable Energy Research Laboratories (DOE NREL) and Battelle.[3] It is available at:

www.gasification.org/Docs/Conferences/1998/gtc9823.pdf

The same authors prepared a technical report in 2000 describing the preliminary operating results at McNeil Station.[4] According to the authors, "operation at the McNeil site has validated the expected performance of the FERCO gasification process and has shown that:

- A medium heating value product gas can be produced from biomass without the use of pure oxygen;
- High biomass throughputs can be achieved in compact reactors; and
- No environmental problems exist with the technology."

The findings above are limited to the gasification system including the combustor. The project at McNeil Station did not demonstrate a cleanup system or the use of the BPG in medium sized CTG such as proposed for the NWFREC. Operation of the gasification system was discontinued at the McNeil Station - for economic reasons. BED continues to operate the McNeil Station as a conventional wood-fueled power plant.

3.5. Char Combustor Exhaust Gas Cleanup

An overall process diagram provided by NWFREC for the proposed energy center including the gasifier, char combustor, cleanup systems and CTG is reproduced in Figure 7.

Char exhaust gas contains little SO_2 because most sulfur leaves the gasifier as H_2S in the raw BPG. Similarly, most of the nitrogen compounds (e.g. NH_3) leave with the raw BPG and are less available for conversion to NO_X in the combustor section. The temperature in the combustor (~1615 °F) is not conducive to thermal NO_X formation compared with the CTG.

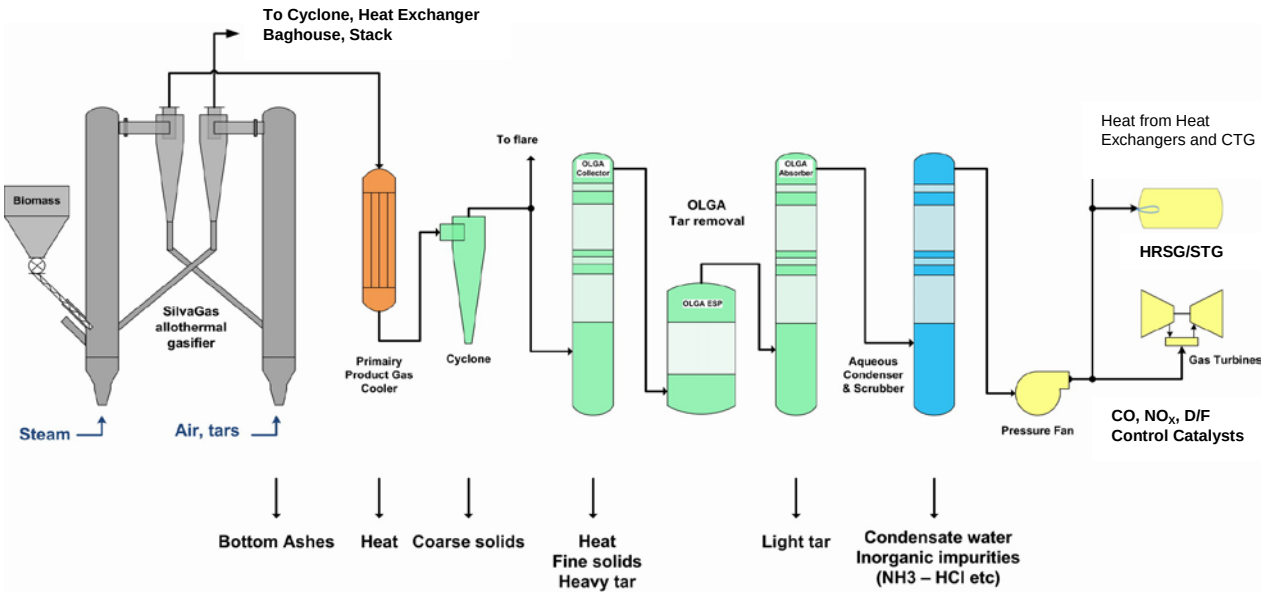

Figure 7. SilvaGas Gasifier/Combustor, NWFREC Cleanup System and Power Generation.

Most sand, ash and unburned char departing with the char combustor exhaust will be removed in the cyclones directly attached to the combustor and directed to the gasifier. Exhaust from the combustor cyclone passes through another cyclone to remove ash and then enters a heat exchanger that is used to produce steam that is fed directly to the STG. The cooled exhaust gas will then pass through a FF baghouse and exhausted to the atmosphere.

3.6. Removal of Tars and Particulate Matter from BPG

The raw BPG and the entrained ash that is not captured in the gasifier cyclone are cooled in a heat exchanger system fed by HRSG feedwater. The resulting steam is fed directly to the STG. The raw BPG passes through a cyclone where coarse particles are removed at temperatures greater than 750 °F which is also greater than the dew point of the heavier components of tars. From that point, the raw BPG can be flared or further cleaned up for use in the CTG.

The presence of tars in the BPG is one of the biggest challenges to commercial application of BIGCC. The tars formed in the gasifier comprises a wide spectrum of straight, branched or ringed organic compounds that can be simply characterized as “heavy tars” and “light tars”.

Heavy tars condense out as the gas temperature drops and can cause major fouling, efficiency loss and unscheduled plant stops. If not removed, tars can confound schemes to use BPG in applications such as fueling CTG. The moisture and tar dew points are critical factors.

The key BPG cleanup system shown in the above diagram is known by the Dutch acronym for “oil-based gas washer” or “**OL**ie **GA**sswasser” (OLGA). The main purpose of OLGA is to remove tars and finer particles from the BPG. The process consists of the following four steps:

1. Heavy tars are condensed upon cooling in an oil scrubber;
2. Fines particles and entrained oil are removed in a wet electrostatic precipitator;
3. Light tars are captured in an absorber; and
4. The oil in the absorber is regenerated in a stripper with air.

The function of the OLGA system and its operating range within the cleanup system is shown in the Figure 8 on the left hand side. The OLGA system lies between the BPG cooler described above and the further water scrubbing described below. The picture in the middle is an example of heavy tar from wood pyrolysis. The picture on the right hand side is of naphthalene crystals from light tars formed on fuel control valves. The OLGA system should remedy such problems. Tar removal is also necessary to prevent fouling in the subsequent wet scrubbing system that would otherwise occur.

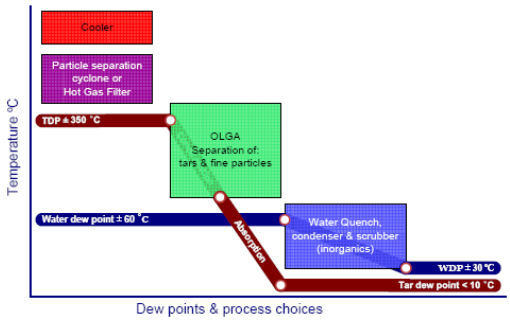

Figure 8. Function of OLGA. Wood pyrolysis tar. Naphthalene pluggage of valves.

According to NWFREC, LLC, Hg will be converted to the elemental state [Hg(o)] in the gasifier rather than oxidized states. Because of temperature considerations, the Hg will follow the BPG stream rather than the char stream.

The OLGA system operates at temperatures greater than the dew point of water, so the vapor pressure of the Hg remains high. It is possible some amount will be returned to the combustor via tars reintroduced to the combustor; however most Hg should depart with the treated BPG from the OLGA system. Similarly, most nitrogen and sulfur compounds (primarily NH_3 and H_2S) will also leave with the treated BPG.

OLGA was developed at the Energy Research Center of the Netherlands (ERCN) circa 2001 specifically for BIGCC applications. The process underwent bench scale and small pilot scale proof of concept demonstrations with the assistance of the Dahlman Industrial group. The findings are summarized in a 2005 report by ERCN available at:[5]

www.ecn.nl/docs/library/report/2005/c05009.pdf

The largest known application of the OLGA system was constructed in Moisannes, France. It is used to clean at least some of the BPG produced from a wine residue and saw dust biomass gasifier. The cleaned BPG from the OLGA system is used to run a 1 MW gas engine-electric generator. The early details are given in a report by ERCN and Dahlman available at:[6]

www.renewableenergy.nl/index.php?pageID=3222&n=546

The photograph on the left hand side of Figure 9 shows the OLGA system at the Moisannes location. The photograph on the right is of a physical model of an OLGA system.

3.7. BPG Scrubbing

Before combusting the BPG in the CTG it is still necessary to reduce the relatively small amounts of NH_3, H_2S and hydrogen chloride (HCl) contained in the treated BPG from the OLGA system. The removal will be accomplished in a wet scrubber at the tail end of the BPG cleanup process. Although the scrubber design is not yet finalized, the wet (water) scrubber will readily

absorb and dissolve gaseous NH_3 and HCl. The scrubber will include a section that will scrub H_2S using caustic soda (NaOH). In addition, the scrubber will likely remove some Hg.

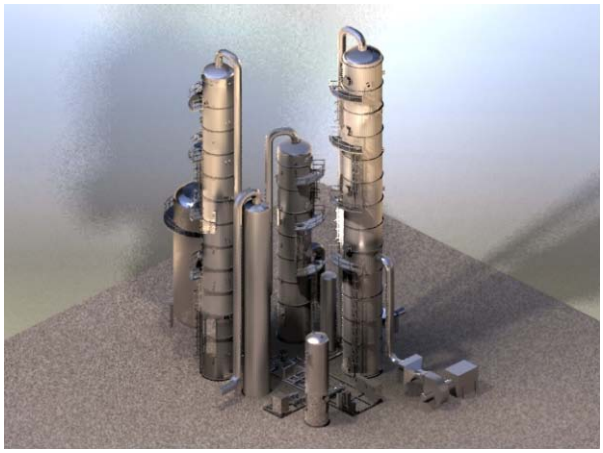

Figure 9. OLGA demonstration in Moisannes, France. Physical model of OLGA.

Equation 4. The acid-base removal of H_2S is accomplished as follows:

$$2NaOH + H_2S \leftrightarrow Na_2S + H_2O$$

Normally Hg(o) is not readily removed by scrubbing with water. However, according to the applicant, Hg(o) will react with H_2S in the first section of the scrubber and precipitate as mercuric sulfide (HgS) that will be filtered in the main recirculating water loop.

BPG will leave the cleanup system at approximately 110 °F and 10 pounds per square inch, gauge pressure (psig). It will be split between two compression and CTG trains.

3.8. BPG and Natural Gas Firing in CTG

BPG Delivered for Combustion

Cooled, sweetened, cleaned BPG is compressed in a pair of two-step BPG compressors and delivered to the CTG. The characteristics of the BPG are given in Table 4. The cleaned BPG can be described as medium heating value fuel.

Table 4. Typical BPG Composition from Silva Gas Process.

Constituent	Product Gas Composition (% by Volume)
Hydrogen (H_2)	20.7
Carbon Monoxide (CO)	45.8
Methane (CH_4)	15.61
Carbon Dioxide (CO_2)	11.03
Ethylene (C_2H_4)	5.26
Ethane (C_2H_6)	0.68
Water (H_2O)	0.22
Nitrogen (N_2)	0.68
Hydrogen Sulfide H_2S	0.02
LHV (Btu/standard ft^3)	435

Description of CTG

BPG will be fired in each CTG. Natural gas, ULSD FO or biodiesel will be used as startup fuels. A CTG is an internal combustion engine that operates with rotary rather than reciprocating motion. They are often called gas turbines because air is the working medium (as opposed to steam).

The applicant proposes to use two nominal 16 MW SOLAR T-130 CTG. Each CTG will have a maximum heat input of 161 million Btu per hour, lower heating value (mmBtu/hr, LHV) when firing BPG. Figure 10 shows an existing gas-fueled combined cycle located in Spain and based on the SOLAR T-130 design used to dry biomass for combustion in a boiler. It also shows an internal diagram from SOLAR of the compressor, combustor and rotor sections of a CTG.

How the CTG Works

Ambient air is drawn into the 14-stage compressor of the T-130 and is compressed to a pressure ratio of 16 times atmospheric pressure. The compressed air is directed to the combustor section, where the fuel from the BPG compressors is introduced, ignited, and burned.

Figure 10. Gas-Fired Unit with T-130 CTG. Diagram of Compressor and Rotor Sections.

The hot combustion gases are then diluted with additional cooling air and directed to the rotor (expansion) section. Energy is recovered in the rotor section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load, which in this case is an electrical generator. Turbine exhaust gas (TEG) is discharged at approximately 925 °F.

Without further heat recovery, the efficiency of the CTG is on the order of 35% based on the electrical energy produced compared with the energy in the delivered BPG.

Evaporative Cooling (EC) or “Fogging”

In addition to the DB feature, the applicant proposes to include a feature whereby fine water droplets are introduced into the CTG compressor inlet air. The practice reduces the compressor inlet air temperature and, in turn, results in greater mass flow rate through the CTG turbine with a boost in electrical power production.

The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Fogging is typically practiced at ambient temperatures of 60° F or higher.

How the HRSG and Steam Turbine-Electrical Generator (STG) work

The heat content and high excess oxygen of the TEG are available to support BPG combustion in the DB located within each HRSG and to provide energy to raise steam and produce additional electricity in the STG. Each DB will be rated at 71 mmBtu/hr (nominal). In addition to steam raised from TEG and DB exhaust, additional steam produced in the heat exchangers within the gasifier island will also be fed directly to the STG. The arrangement whereby steam is raised using the TEG is known as a combined cycle. An example of a combined cycle unit fueled by natural gas is shown in Figure 11 below.

The overall efficiency of a BIGCC will be less than the standard combined cycle firing natural gas. This is due to the various transformations of the basic fuel, pressure drops, additional BPG compression, heat losses through liquid and solid effluents and the basic laws of thermodynamics. The expectation is that the proposed project will achieve overall (net) 40% efficiency on a higher heating value (HHV) basis.

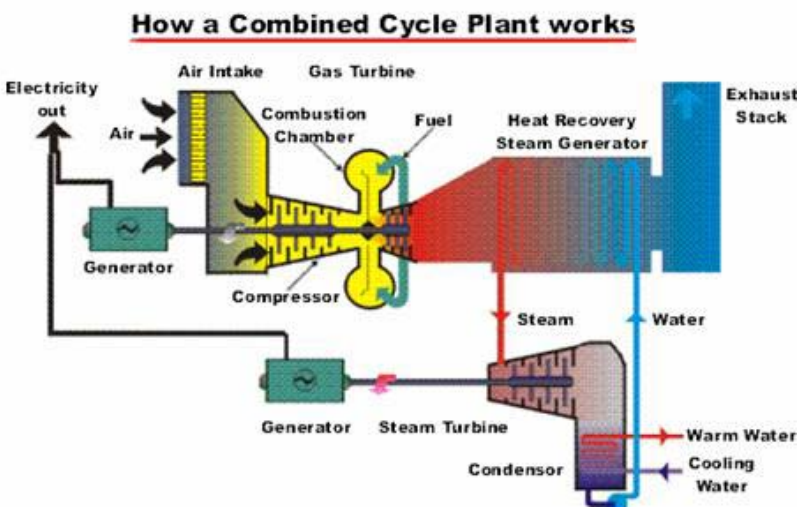

Figure 11. A conventional natural gas fueled combined cycle unit.

4. RULE APPLICABILITY

4.1. Federal Regulations

This project may be subject to certain provisions regarding air quality established by the Environmental Protection Agency (EPA) in the Code of Federal Regulations (CFR), including:

Title 40	Description
Part 60	New Source Performance Standards: 40 CFR 60 Subparts A, Dc and KKKK
Part 70	State Operating Permit Programs
Parts 72,73	Acid Rain – Permits, SO_2 Allowance System
Parts 75-77	Acid Rain – NO_X Emissions Reduction Program, Excess Emissions

4.2. State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following rules in the F.A.C.

Chapter	Description
62-4	Permits
62-204	Air Pollution Control – General Provisions
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Requirements For Sources Subject To The Federal Acid Rain Program
62-296	Stationary Sources - Emission Standards
62-297	Stationary Sources - Emissions Monitoring

4.3. Potential Emissions and PSD Non-Applicability Determination

The Department regulates major stationary sources of air pollution in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. Per Rule 62-210.200(Definitions), F.A.C., a major stationary source is

1. Any of the following stationary sources of air pollutants which emits, or has the PTE, 100 TPY or more of any PSD pollutant:
   - Fossil fuel-fired steam electric plants of more than 250 mmBtu/hr heat input,
   - Coal cleaning plants (with thermal dryers),
   - Kraft pulp mills,
   - Portland cement plants,
   - Primary zinc smelters,
   - Iron and steel mills,
   - Primary aluminum ore reduction plants,
   - Primary copper smelters,
   - Municipal incinerators capable of charging more than 250 TPD of refuse,
   - Hydrofluoric, sulfuric, or nitric acid plants,
   - Petroleum refineries,
   - Lime plants,
   - Phosphate rock processing plants,
   - Coke oven batteries,
   - Sulfur recovery plants,
   - Carbon black plants (furnace process),
   - Primary lead smelters,
   - Fuel conversion plants,
   - Sintering plants,
   - Secondary metal production plants,
   - Chemical process plants,
   - Fossil-fuel boilers (or combination thereof) totaling more than 250 mmBtu/hr heat input,
   - Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels,
   - Taconite ore processing plants,
   - Glass fiber processing plants,
   - Charcoal production plants;

2. Any stationary source which emits, or has the PTE, 250 TPY or more of a PSD pollutant; or
3. Any physical change that would occur at a stationary source not otherwise qualifying as a major stationary source, if the change would constitute a major stationary source by itself.

The category of BIGCC is not among the bulleted stationary sources listed in paragraph 1. above that would be classified as a major stationary source based on the PTE 100 TPY of a PSD pollutant. The proposed NWFREC is not an existing stationary source and not subject to paragraph 3. above. To be considered a major stationary source, it would be necessary for annual emissions of a PSD pollutant from the NWFREC to equal or exceed 250 TPY.

The project will (at least) result in emissions of NO_X, CO, particulate matter (PM, PM_{10} and $PM_{2.5}$ - for which PM_{10} is a surrogate), SO_2, and small amounts of sulfuric acid mist (SAM), VOC and hazardous air pollutants (HAP). Table 5 summarizes the applicant's estimates of key pollutants including those from the CTG, DB, char combustor, flares, material handling, an auxiliary boiler and cooling towers.

Table 5. Applicant's estimate of annual emissions from the NWFREC in TPY.

Pollutant	CTG/DB	Char Combustor	Cooling Towers	Material Handling	Aux. Boiler	Flares	Dryer	Total
SO_2	7.9	13.1	0	0	0.09	0.05	0	21.1
PM	22.8	2.5	1.03	12.4	0.03	Neg	0.10	38.9
PM_{10}	22.8	2.5	0.73	6.78	0.03	Neg	0.01	32.9
NO_X	120	41.7	0	0	1.47	1.58	0	164.8
CO	110.4	13.9	0	0	1.24	8.59	0	134.1
VOC	13.7	6.9	0	0	0.08	3.25	0	24
SAM	<4	<3	0	0	Neg	Neg	0	<7
HAP	4	1	Negligible (Neg)					5
Hg	Neg	6 lb/yr	Neg					6 lb/yr
NH_3	23	Emissions from CTG/DB are "slip" from SCR. Rest assumed neg.						23
Fluoride (F)	Neg							~0
Lead (Pb)	Neg							~0

No PSD pollutant emissions will equal or exceed 250 TPY, based on operation design and associated emission limits. Therefore, the NWFREC will not be subject to the PSD rules including PSD ambient air modeling or a requirement for a best available control technology (BACT) determination under that program.

4.4. New Source Performance Standards and National Emissions Standards for HAP

The CTG and the DB located in the HRSG are subject to 40 CFR 60, Subpart KKKK as cited above. The emission standards for the size category of the CTG that will be used at the NWFREC (> 50 mmBtu/hr and ≤ 850 mmBtu/hr) are given in the following table and also account for DB emissions.

Table 6. Emission standards applicable to NWFREC based on 40 CFR 60, Subpart KKKK.

New CTG Type	NO_X Emission Standard	SO_2 Emission Standard
Firing natural gas	25 ppmvd @15% O_2	0.060 lb SO_2/mmBtu
Firing fuels other than natural gas	74 ppmvd @15% O_2	

Purchase contracts or tariff sheets can be used in place of fuel sulfur content monitoring when using natural gas by demonstrating sulfur content of no more than 20 grains/100 standard cubic feet (gr/SCF) of natural gas.

40 CFR 60, Subpart A – General Provisions are applicable to the affected sources for which standards have been promulgated under Section 111, Clean Air Act. The sources subject to Subpart KKKK are therefore also subject to Subpart A. In addition to the emission standards in Subpart KKKK, the two subparts include requirements for notification, record keeping, performance testing, and monitoring of operations that are applicable to the NWFREC.

Subpart KKKK will be the primary basis for the permit conditions related to the CTG and DB, especially since a BACT determination is not required. Some provisions in addition to Subpart KKKK are included in the draft permit conditions to limit the PTE individual PSD pollutants from the entire facility to less than 250 TPY. These include, for example, 12-month rolling average limitations on NO_X and CO.

The applicant has proposed a NO_X limit of 14.9 ppmvd @15% O_2 on a 30-day rolling average when burning BPG instead of the Subpart KKKK values of 74 ppmvd @15% O_2 cited above. The lower emission concentration value will effectively limit PTE from each HRSG (CTG/DB) stack to approximately 13.7 pounds per hour (lb NO_X/hr) and to 120 TPY from the two HRSG stacks combined.

Because the NWFREC is not a major source of HAP, it will not be subject to any regulations pursuant to 40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants (NESHAP) for source categories. Among the key provisions that do not apply are those of 40 CFR 63, Subpart YYYY - NESHAP for Stationary Combustion Turbines. Even if the NWFREC were a major source of HAP, the applicability of Subpart YYYY has been stayed for lean premix and diffusion flame gas-fired CTG including the type planned for this project.

Startup burners for the gasifier and the char combustor are required. The two burners will have nominal ratings of 25 and 17 mmBtu/hr, respectively. These burners will operate on the order of 14 hours each during cold startup and will slowly heat olivine, gasifier and combustor surfaces, heat exchangers, and eventually feedwater thus producing steam.

The function of these devices appears to fit within the definition of a *steam generator unit* as the term is used in 40 CFR 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

"Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other transfer medium….. This term does not include process heaters as defined in this subpart.

"Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst."

Besides heating vessel surfaces, ducts, water (producing steam) the two burners also heat olivine. The heated olivine initiates the pyrolysis of the woody biomass. In certain applications, though not in this one, olivine impregnated with nickel breaks down tars. In the present application, it does not participate as a reactant or as a catalyst. Therefore, the burners are not exempt from Subpart Dc.

An auxiliary boiler with a nominal capacity of 62 mmBtu/hr will be included in the project for the purpose of providing steam as the conveyance medium in the gasifier during startup. It will also provide steam to preheat the STG during startup. The auxiliary boiler is clearly subject to Subpart Dc.

The Department also considered the applicant's assertions that none of the following federal regulations is applicable and concludes (based on previous informal consultations with various offices of EPA about an identical project) they do not apply to the NWFREC:

- 40 CFR 60, 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.
- 40 CFR 60, 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.
- 40 CFR 60, Subpart RRR—Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes.

4.5. Other Department Rules Potentially Applicable to the Project

The Department reviewed the following regulations and concluded that they do not apply to the NWFREC:

- Section 62-296.401, F.A.C. - Incinerators;
- Section 62-296.410, F.A.C. - Carbonaceous Fuel Burning Equipment; and
- Section 62-296.416, F.A.C. - Waste-to-Energy Facilities.

Incinerators and waste to energy facilities combust waste. The fuel slate authorized by this permit does not constitute a waste or municipal solid waste.

Carbonaceous fuel is defined in Rule 62-210.200, F.A.C. as "solid materials composed primarily of vegetative matter such as tree bark, wood waste, or bagasse". Although such materials are pyrolized (not burned) to make BPG and char, the resulting products that are subsequently combusted do not meet the definition.

5. EMISSIONS FORMATION AND CONTROL

5.1. NO_X Formation

NO_X forms in the CTG as a result of the dissociation of molecular N_2 and O_2 to their atomic forms and subsequent recombination into seven different oxides of nitrogen. It also forms by oxidation of nitrogen present in the fuel.

Thermal NO_X. Thermal NO_X forms in the high temperature area of the CTG combustor as seen on the left hand side of Figure 12.

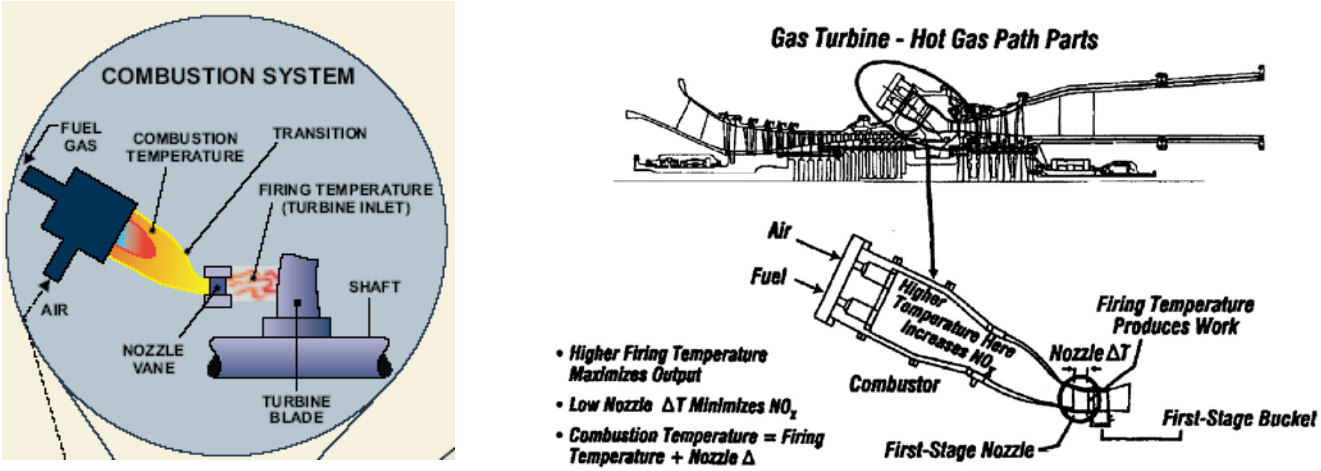

Figure 12. Relation between Combustion and Firing Temperatures and NO_X Formation.

Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The relationship between flame and firing temperature, output and NO_X formation are depicted in the right side of Figure 12, which is from a GE discussion on these principles.

In all but the most recent CTG combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle.

BPG is mostly hydrogen and CO and will combust with a high flame temperature on the order of 4,300 °F in the SOLAR T-130 CTG. The applicant estimates pre-control emissions at approximately 325 ppmvd @15% O_2 from the CTG for this project.

On the other hand, thermal NO_X concentrations from the char combustor will be relatively low because combustion occurs in a CFB at approximately 1615 °F which is about 1000 °F lower than the temperature at which thermal NO_X formation is of significance.

<u>Prompt NO_X</u> is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion. Prompt NO_X formation within the CTG combustor is believed to be minimal. Prompt NO_X is not important in the char combustor because there is no flame front in the CFB.

<u>Fuel NO_X</u> is formed when fuels containing bound nitrogen or reduced nitrogen compounds (such as NH_3) are burned. This phenomenon is not important when the unit fires natural gas or when NH_3 has been removed in BPG prior to combustion. However the presence of NH_3 is the critical consideration in the proposed project when firing syngas.

Fuel NO_X is not important in the char combustor because the char is practically devoid of nitrogen.

5.2. NO_X Control

There are several NO_X reduction processes available without the need to install add-on control equipment. These include varieties of staged combustion or wet injection of diluent to control NO_X formation. The SOLAR version of dry low NO_X (DLN) combustion is called $SoLoNO_X$. According to SOLAR, this technology is not available for this application because the heating value (actually the Wobbe Index) of the BPG is not within the range that supports lean premix combustion.

According to SOLAR, despite the low heating value, BPG burns hot enough to allow a moderate level of water injection into the combustors to reduce NO_X emissions prior to addition polishing by add-on control equipment.

In addition to water injection, the applicant will install SCR, which is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst.

Equation 5. NH_3 reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water according to the following simplified reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium (V) and titanium oxide (TiO_2) formulations and account for most installations.

Given water injection and SCR, the Department has reasonable assurance that the NWFREC project can achieve the reduction from 325 ppmvd @15% O_2 to consistently meet the levels necessary to meet both the Subpart KKKK limits of 74 and 25 ppmvd @15% O_2 for BPG and natural gas respectively.

The applicant has requested a BPG-based limit of 14.9 ppmvd that will also provide reasonable assurance that the PTE NO_X from the facility will be less than 250 TPY of NO_X. For convenience in reporting, the limit will be established at 15.0 ppmvd@15% O_2.

Figure 13 (from Nooter-Eriksen) is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor and the NH_3 injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met.

Figure 14 is a photograph of the Progress Energy Florida (PEF) Hines Power Block I, which is much larger than the proposed NWFRC. The external lines to the NH_3 injection grid are easily visible. SCR catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive NH_3 use can increase emissions of CO, NH_3 (slip) and $PM_{10}/PM_{2.5}$ when sulfur-bearing fuels are used.

The low NO_X formation potential of the char combustor (due to relatively low char nitrogen and low firing temperature) was previously above. In contrast to the CTG/DB, additional NO_X controls are not needed. The applicant estimated NO_X emissions from the char combustor at 41.7 TPY (approximately equal to 9.5 lb/hr).

The Department will require annual testing of the char combustor to provide further assurance and to verify that (in conjunction with emissions from the CTG/DB) the facility-wide emissions of NO_X will be less than 250 TPY.

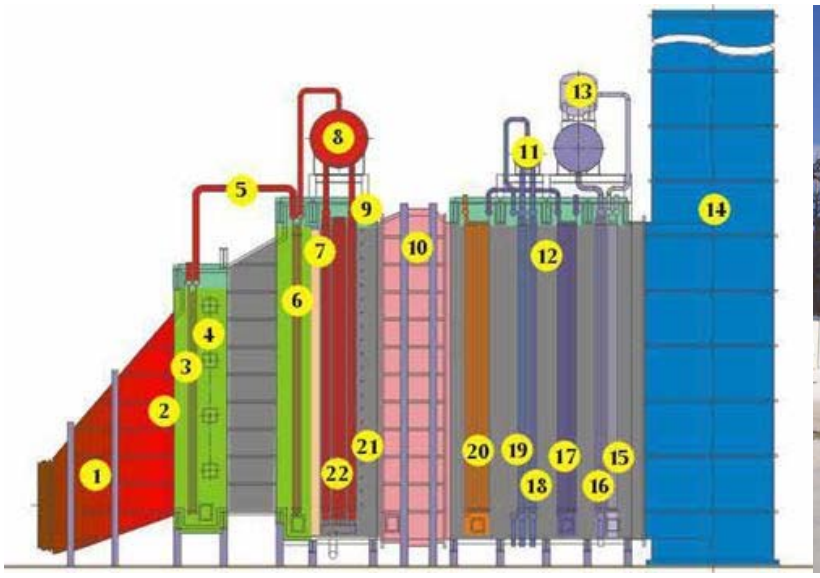

Figure 13 – Key HRSG Components (10 is SCR). **Figure 14 – PEF Hines Block I.**

5.3. Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) Formation and Control

The main control for SO_2 for the NWFREC is the prevention of its formation through use of low sulfur feed and fuel. All of the biomass sources given in Table 2 contain much less sulfur (S) than bituminous coal which contains 1.52 percent as shown in Table 2.

As previously discussed, sulfur is released as H_2S in the gasifier and is primarily contained in the BPG rather than the char. The wet scrubber in the clean up process includes a caustic section that will remove H_2S as sodium sulfide (Na_2S).

SO_2 and SAM form from the small amount of H_2S reaching the CTG and DB as a result of the oxidation (combustion) of sulfur-containing molecules.

Equation 6. H_2S present in the syngas combines with O_2 as follows:

$$2H_2S + 3O_2 \rightarrow 2SO_2 + 2H_2O$$

Equation 7. SO_2 is further oxidized depending on the presence of O_2, temperature, and water vapor to yield SAM by the following reactions:

$$2SO_2 + O_2 \rightarrow 2SO_3 \quad \text{and} \quad SO_3 + H_2O \rightarrow H_2SO_4$$

The applicant estimated that prior to clean up, the concentration of H_2S in the BPG will be 0.02%. The emissions from burning cleaned BPG in the CTG will be 0.90 lb SO_2/hr from each HRSG. This equates to emissions of 0.002 lb SO_2/mmBtu and is much less than the limit of 0.060 lb SO_2/mmBtu required by Subpart KKKK.

Compliance with a fuel sulfur based on the pre-control H_2S concentration of 0.02% S in the BPG will be sufficient to demonstrate compliance with the Subpart KKKK limit of 0.060 SO_2 lb/mmBtu with an ample margin of safety. It is also sufficient to insure that the facility will not be a major stationary source of SO_2.

5.4. CO and VOC Formation and Control

CO and VOC Formation and Combustor Characteristics

CO and VOC are emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO and VOC. The control techniques are based upon high temperature, sufficient time, turbulence and excess air.

Except for avoidance of PSD by emitting less than 250 TPY, there are no CO or VOC limitations from any specific air regulations (including Subpart KKKK) that are applicable to the NWFREC.

Emissions from the CTG should be low given the high BPG firing temperature (that results in high pre-control NO_X emissions). Further firing of BPG in the DB is accomplished in an atmosphere of hot TEG, high O_2 content and turbulence. Typically under such conditions, CO concentrations, if not mass emission rates, are actually reduced by the DB.

Table 7 is a summary of CO and VOC emissions estimated by the applicant from the CTG/HRSG stacks after control and including emissions from the char combustor.

Table 7. Projected CO and VOC from HRSG (CTG/DB) and Char Combustor at NWFREC.

Location	Mass Rate (lb/hr)		Annual Emissions (TPY)	
	CO	VOC	CO	VOC
Each HRSG stack	12.6	1.6	55.2	6.85
Two HRSG stacks	25.2	3.2	110.4	13.7
Char Combustor	3.2	1.6	13.9	6.9
HRSG+Combustor	28.4	4.8	124.3	20.6

The applicant estimated CO emissions from the char combustor at 3.2 lb/hr and 13.9 TPY. The basis was the comparison to combustion of anthracite coal that, like char, contains minimal amounts of volatile components. The CO emissions will depend a great deal on the residence time in the CFB within the char combustor and the extent to which it interacts with the tar from the OLGA process.

The Department will conservatively assume for the purposes of this review that CO emissions from the char combustor will actually be closer to 5 lb/hr and 21.9 TPY and will require measurement to provide further assurance and to verify that the facility-wide emissions of CO will be less than 250 TPY. A CO limit is also appropriate to insure good char burnout thereby minimizing HAP emissions. The Department will require installation of a CO process monitor and recordkeeping to insure implementation of good combustion practices.

The applicant proposes to install oxidation catalyst within the HRSG to control CO and VOC emissions from combustion of BPG. By using oxidation catalyst, there is reasonable assurance that facility-wide emissions of CO and VOC will be substantially less than 250 TPY and insures the facility will not exceed the PSD major stationary source threshold.

5.5. NH_3 Emissions (slip)

The applicant estimated NH_3 (slip) emissions of 4.9 ppmvd @15% O_2 from the SCR system. The Department routinely sets NH_3 limits of 5 ppmvd @15% O_2 for combined cycle projects that

rely on wet water injection or DLN combustion in conjunction with SCR for NO_X control to ensure good efficient operation of the control system.

The Department will set an NH_3 limit of 5 ppmvd @15% O_2. This should not be difficult to achieve because the NO_X limit will not be very low (15 ppmvd) in comparison with typical natural gas-fueled combined cycle projects. Also much of the NO_X reduction will be accomplished by the water injection system prior to the SCR system. Estimated annual emissions from the two HRSG stacks will be approximately 23 TPY.

With the relatively low SO_2 emissions, the possibility of a visible plume will be minimal. There are no other specific NH_3 limits applicable to the facility and NH_3 is not a PSD pollutant.

NH_3 from char combustion will be minimal due to the fact that most NH_3 is contained in the BPG and the small amount of NH_3 in the char and tar would be burned to NO_X.

5.6. Particulate Matter (PM/PM_{10}) Control

PM/PM_{10} Formation and Control Options

PM and PM_{10} emitted from combustion turbines are typically due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion. BPG and natural gas will be the only fuels fired and are efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperatures and pressures. Natural gas is an inherently clean fuel and contains no ash.

The BPG will contain gasifier ash prior to the cleanup system shown in Figure 7 above. The cleanup includes solids removal in the gasifier cyclone, the coarse solids cyclone and fine solids removal features of the OLGA system. Finally, efficient and high temperature combustion of the BPG in the CTG and DB will minimize emissions of PM/PM_{10}.

The applicant estimated PM/PM_{10} emissions from each HRSG stack at the proposed NWFREC at 2.6 lb/hr and 11.4 TPY. The very high combustion temperatures, use of inherently clean natural gas or cleaned BPG, and inclusion of an NH_3 limit will insure that PM/PM_{10} emissions will be as low as estimated by the applicant. The Department will set a limit 2.6 lb/hr per HRSG stack as estimated by the applicant and a visible emission standard of 10% opacity to provide continuous reasonable assurance of low PM/PM_{10} emissions that will be less than the PSD thresholds.

The applicant estimates PM/PM_{10} emissions of approximately 0.6 lb/hr and 2.5 TPY from the char combustor. The estimates appear reasonable based on the sand recovery cyclone, an ash removal cyclone and a fabric filter baghouse. The applicant estimates PM/PM_{10} removal efficiency of 98% between the ash cyclone and the baghouse.

The Department will set limit a PM/PM_{10} limit at 2.5 lb/hr on the char combustor. The Department will also require installation of a continuous opacity monitoring system (COMS) on the char combustor exhaust stack and adherence to a 10% opacity standard to further minimize both visible emissions and particulate matter. These measures will suffice to insure low emissions and that the facility will not be a major stationary source of PM/PM_{10} emissions.

The applicant identified materials handling as the other main source of PM/PM_{10} emissions. The associated transfer points will be controlled by baghouses.

5.7. Mercury (Hg) Control

As noted in Table 4 above, estimated emissions of Hg are controlled to approximately 6 lb/yr by the caustic scrubber that is incorporated within the BPG cleanup system. For reference, major stationary sources that exceed 250 TPY of a PSD pollutant must conduct a BACT determination for Hg if such emissions will exceed the significant emission rate (SER) of 200 lb/yr. The emissions rate from this facility will be very low compared with the Hg SER.

5.8. Dioxin and Furan (D/F) Control

D/F constitute a class of cyclic halogenated hydrocarbons with halogen atoms (such as chlorine) substituting some of the points in the ringed structures normally occupied by hydrogen. Furthermore two ringed halogenated hydrocarbons are joined to each other in such a manner that involves at least one oxygen molecule.

Following is the example of 2,3,7,8 tetrachlorodibenzo-p-dioxin (2378-TCDD). A model of cellulose is included for comparison. The furan version would have just one oxygen molecule.

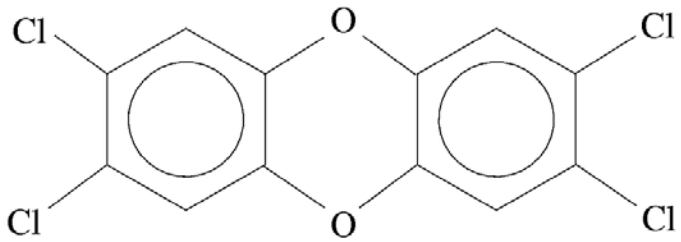

Figure 15 – Skeletal diagram of the 2,3,7,8 TCDD molecule.

The key to D/F control is to avoid its formation and promote its destruction. Woody biomass generally contains much less chloride than coal or municipal solid waste containing plastics. The relatively small amount of hydrogen chloride formed in the gasifier and contained in the raw BPG will be largely removed in the wet scrubber prior to combustion in the CTG/DB.

Burning the BPG at high temperatures and with very high excess O_2 in the CTG/DB will destroy any ringed structures including D/F. Finally SCR, such as incorporated into the NWFREC project, has been shown to be effective in the destruction of D/F. Significant opportunities for D/F to reform do not exist if for no other reason than the absence of chlorine in the scrubbed BPG.

The possibilities for dioxin emissions exist from the char/tar combustion. The raw BPG contains a variety of compounds including tars as discussed above. The tars are formed by the pyrolysis of cellulose, which is an organic compound $(C_6H_{10}O_5)_n$, consisting of a linear chain of several hundred to over ten thousand linked glucose units as shown below:

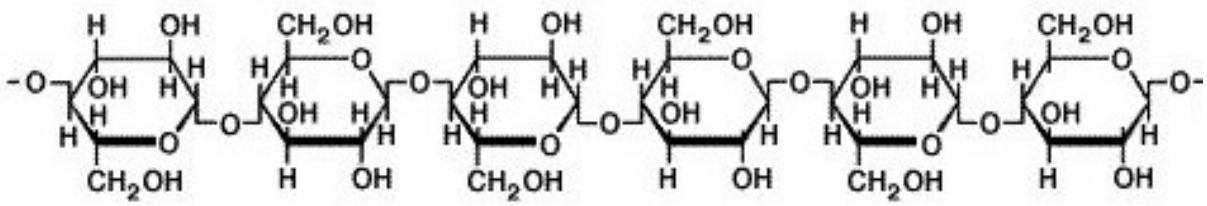

Figure 16 – Skeletal diagram of cellulose.

The breaking of the many ringed compounds provides the opportunity to form many types of ringed compounds that comprise tars. In the presence of chlorides, the opportunity for D/F formation exists. These compounds (tars as well as any small quantities of D/F formed from the raw BPG) are removed by the OLGA system. According to the applicant, the oils used to scrub tars within the OLGA system are comprised of hydrocarbons that do not contain chlorine.

There are a number of reasons that suggest relatively low D/F emissions from the char combustor exhaust. These include:

- Relatively low chlorides in the feedstock;
- Removal of most chlorides such as HCl in the wet scrubber system;
- Inherently low metal concentrations in the feedstock such as copper that can otherwise catalyze HCl to chlorine (Cl_2) for participation in D/F formation;
- Destruction of D/F in tars within the CFB of the char combustor;
- Maintenance of relatively high temperature with a long residence time from the char combustor through the riser and to the hot ash cyclone;
- Rapid cooling (quenching) in the heat exchanger that heats HRSG feedwater; and
- Further removal in the baghouse.

While it cannot be concluded that D/F emissions will be zero, it can be concluded that such emissions will be less than from sources for which EPA has established D/F limits such as cement plants and waste-to-energy (WTE) facilities. The present limits applicable to new cement plants (depending on operating mode) are 0.2 and 0.4 nanograms toxic equivalent (TEQ) per dry standard cubic meter (ng/dscm) at 7% O_2. The value applicable to new WTE units is 13 ng/dscm @7% O_2.

A reasonable action level would be 0.15 TEQ ng/dscm. Beyond that value, the applicant would need to consider activated carbon injection in the baghouse or other actions such as temperature management and residence time options.

6. STARTUPS OF THE GASIFIER AND CHAR COMBUSTOR

The applicant submitted information regarding the sequence of events and emissions that occur during the startups, planned shutdowns or emergency shutdowns of key facility components such as the gasifier and char combustor. Following is a summary of the procedures submitted by NWFREC, LLC.

6.1. Gasifier Startups and Shutdowns

The initial startup of the gasifier will utilize a blower to force air into the gasifier. One hour later, a 25 mmBtu/hr natural gas fired burner will be started. The burner will fire for approximately 12 hours. During this time, the sand bed will be heated to the operating temperature of approximately 1,600 °F and will begin fluidizing. At this point the burner will be turned off and woody biomass and steam will begin to be fed into the gasifier. After one hour, the woody biomass feed rate will be gradually increased to approximately 30 TPH. This ramp up of the feed rate will take roughly one hour. Also during this time, the gasifier blower will be turned off and over the next hour the gasifier should reach steady state conditions.

Routine shutdowns of the gasifier are planned in advance and follow an orderly process. The general process is as follows:

- Prepare the gasifier for shutdown by reducing the woody biomass feed rate to 50 percent of the design rate;
- Start the gasifier air blower and open the bypass;
- Stop the biomass feed, monitor BPG flowrate and the CO and CO_2 composition of the BPG;
- Gradually increase blower airflow into the gasifier using CO and CO_2 levels to determine when woody biomass (carbon) burn out has occurred;
- Gradually reduce steam flow to zero;
- Maintain adequate upward flow during the transition from steam to air flow; and,
- Stop airflow into the gasifier once carbon burnout has occurred.

6.2. Combustor Startups and Shutdowns

The startup of the combustor follows the same general procedures and timelines as the gasifier. However, instead of woody biomass, char from the gasifier and tars from the OLGA gas cleanup system are feed to the combustor toward the end of the startup process. Also, instead of steam, air flows into the combustor during steady state operation.

The combustor has no specific shutdown sequence. Airflow is maintained at the design rate to maintain bed fluidization and allow the burnout of char and tars. The combustor blower is turned off at the same time as the gasifier blower.

7. AMBIENT AIR QUALITY

7.1. Introduction

The proposed project will not increase emissions at levels in excess of PSD significant amounts. Therefore, an ambient air quality modeling analysis was not required for this project. However, the applicant provided an ambient air quality analysis to show compliance with the Ambient Air Quality Standards (AAQS). The following sections include the AAQS analysis, a review of current air quality in the vicinity of the project, and information regarding this project and how it relates to other nearby sources of pollution.

7.2. Major Stationary Sources Nearest to the Project

The current largest stationary sources of air pollution in Florida counties within approximately 100 miles of the project site are listed below. The information is from annual operating reports submitted to the Department from 2008 and the future estimate for the NWFREC project.

Table 8. - Largest Sources of SO_2 Nearest to the Project.

Owner	Site Name	TPY
Gulf Power Company	Lansing Smith Power Plant - Bay	15,063
Gulf Power Company	Scholz Power Plant	2,707
Smurfit-Stone Container	Panama City Mill	2,655
St. Marks Powder	St. Marks Powder	72
City of Tallahassee	Hopkins Power Plant	44
NWFREC	**NWFREC (proposed)**	**21**
Arizona Chemical	Port. St. Joe Facility	20

Table 9. - Largest Sources of PM/PM_{10} Nearest to the Project.

Owner	Site Name	TPY
Gulf Power Company	Lansing Smith Power Plant - Bay	803
Smurfit-Stone Container	Panama City Mill	643
Green Energy BioEnergy	Jackson County Facility	158
Coastal Forest Resources Co.	Havana Plywood Plant	148
Gulf Power Company	Scholz Power Plant	128
North Florida Lumber	North Florida Lumber	84
Georgia Pacific Wood Products	Hosford Facility	83
Spanish Trail Lumber Co.	Marianna Sawmill	50
St. Marks Powder	St. Marks Powder	45
City of Tallahassee	Purdom Power Plant	41
Rex Lumber	Graceville Mill	41
NWFREC	**NWFREC (proposed)**	**40**
BASF	Quincy Site	40
City of Tallahassee	Hopkins Power Plant	37

Table 10. - Largest Sources of CO Nearest to the Project.

Owner	Site Name	TPY
Smurfit-Stone Container	Panama City Mill	6,410
Gulf Power Company	Lansing Smith Power Plant - Bay	522
City of Tallahassee	Hopkins Power Plant	365
North Florida Lumber	North Florida Lumber	144
NWFREC	**NWFREC (proposed)**	**134**
Bay County	Bay Waste-to-Energy Facility	120
Georgia Pacific Wood Products	Hosford Facility	106
City of Tallahassee	Purdom Power Plant	106
Spanish Trail Lumber Co.	Marianna Sawmill	100

Table 11. - Largest Sources of VOC Nearest to the Project.

Owner	Site Name	TPY
Smurfit-Stone Container	Panama City Mill	842
St. Marks Powder	St. Marks Powder	445
North Florida Lumber	North Florida Lumber	237
Spanish Trail Lumber Co.	Marianna Sawmill	237
Rex Lumber	Graceville Mill	234
Coastal Forest Resources Co.	Havana Plywood Plant	224
Arizona Chemical	Panama City Facility	211
Trane	Lynn Haven Operation	92
Gulf Power Company	Lansing Smith Power Plant - Bay	78
Northwest Florida Holdings	Allanton Facility	69
Arizona Chemical	Gulf County Facility - Shutdown	56
The Printing House	The Printing House Gadsden	55
Green Energy BioEnergy	Jackson County Facility	49
Chevron	Panama City Terminal	34
Spurlin Industries	Spurlin Industries	33
Georgia Pacific Wood Products	Hosford Facility	30
NWFREC	**NWFREC (proposed)**	**24**
FL Gas Transmission	Station 13 Washington	24

Table 12. - Largest Sources of NO_X Nearest to the Project.

Owner	Site Name	TPY
Gulf Power Company	Lansing Smith Power Plant - Bay	5,733
Smurfit-Stone Container	Panama City Mill	1,518
Gulf Power Company	Scholz Power Plant	1,186
FL Gas Transmission	Station 13 Washington	643
FL Gas Transmission	Station 14 Gadsden	538
City of Tallahassee	Hopkins Power Plant	284
City of Tallahassee	Purdom Power Plant	230
Georgia Pacific Wood Products	Hosford Facility	165
NWFREC	**NWFREC (proposed)**	**165**
Bay County	Bay Waste-to-Energy Facility	134
Green Energy BioEnergy	Jackson County Facility	92
Coastal Forest Resources Co.	Havana Plywood Plant	91

By comparison with other sources in the region, the NWFREC project will be a relatively small source of air pollution.

7.3. Regional Ambient Air Quality Monitoring

The Departments operates more than twenty-three monitors at eleven sites measuring nitrogen oxides (NO_2), SO_2, $PM_{2.5}$ and ozone (O_3). The 2008 monitoring network in the region of the proposed project in Gulf County is shown in the figure below.

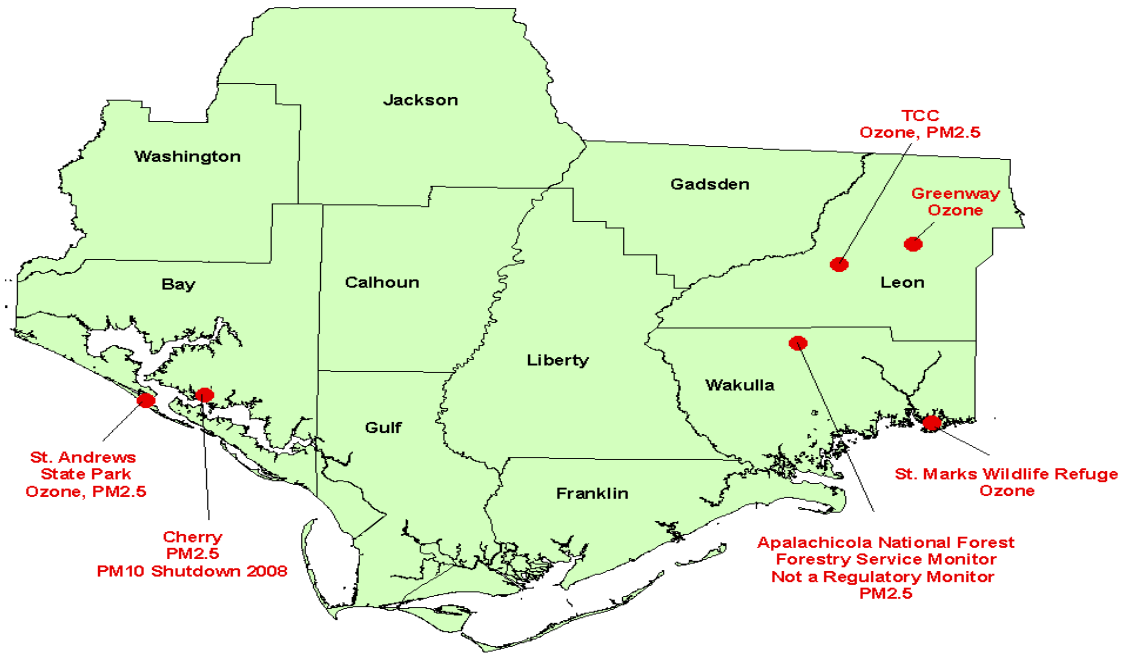

Figure 17. - Ambient Air Monitoring Stations nearest to the Project Location.

Pollutant monitored concentrations are summarized in Table 13. Currently all monitors in Florida are characterized as being in attainment with the AAQS. However some ozone monitors, such as the monitor nearest to the proposed project, are showing concentrations above the standard.

Regardless of further attainment demonstrations with regards to ozone, the proposed project is relatively small in a region that contains much larger sources of ozone precursors (NO_X, VOC). Since ozone is a regional pollutant with levels of concentrations highly dependent on meteorology, it is reasonable to conclude that one minor stationary source with relatively low emissions will not impact ozone concentrations in a significant manner.

While all criteria pollutants are not monitored in the region shown (e.g. CO and SO_2), it is reasonable to assume that the region is in attainment for those pollutants since monitors are placed depending on stationary sources of pollution and population. For example, the nearest sulfur dioxide monitor is located in Hamilton County near the White Springs facility which emitted over 3000 TPY of SO_2 compared with approximately 30 TPY expected from the NWFREC.

Table 13 - Ambient Air Quality Nearest to Project Site (2008).

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units [a]
PM_{10}	Panama City[h]	24-hour	53	50		150 [b]	$\mu g/m^3$
		Annual			22[i]	50 [c]	$\mu g/m^3$
$PM_{2.5}$	Panama City	24-hour	28	21		35 [d]	$\mu g/m^3$
		Annual			10	15 [e]	$\mu g/m^3$
SO_2	White Springs	3-hour	103	20		500 [f]	ppb
		24-hour	15	8		100 [f]	ppb
		Annual			2	20 [c]	ppb
NO_2	Pensacola	Annual			5	53 [c]	ppb
CO	Jacksonville	1-hour	9	6		35 [f]	ppm
		8-hour	3	3		9 [f]	ppm
Ozone	Panama City	8-hour	85	80		75 [g]	ppb
		4th highest high	75			75 [g]	ppb

a. Units are in: micrograms per cubic meter ($\mu g/m^3$); parts per billion (ppb); or parts per million (ppm).
b. Not to be exceeded on more than an average of one day per year over a three-year period.
c. Arithmetic mean.
d. Three year average of the 98th percentile of 24-hour concentrations.
e. Three year average of the weighted annual mean.
f. Not to be exceeded more than once per year.
g. Three year average of the 4th highest daily maximum.
h. No longer operating in 2009.
i. Incomplete data for regulatory purposes.

According to Table 13, the area is in attainment with the $PM_{2.5}$ (also called PM fine) standards. $PM_{2.5}$ is primarily influenced by man-made and natural precursors in the atmosphere on a regional basis rather than locally. Regionally, man-made precursors of PM fine (e.g. SO2 and NO_X) are orders of magnitude higher than what would be found locally. Figure 18 shows how a PM fine monitor located in Tallahassee, Leon County was affected by a regional high sulfate (SO_4 from SO_2) event. For reference the peak $PM_{2.5}$ value occurred on September 14, 2005.

The regional nature of the event (and the role of precursors) can be appreciated based on the map in Figure 19 showing a "sulfate" event that occurred on September 14, 2005. The zones of high concentration encompassed a large portion of the Florida Panhandle including Gulf, Leon and other nearby counties.

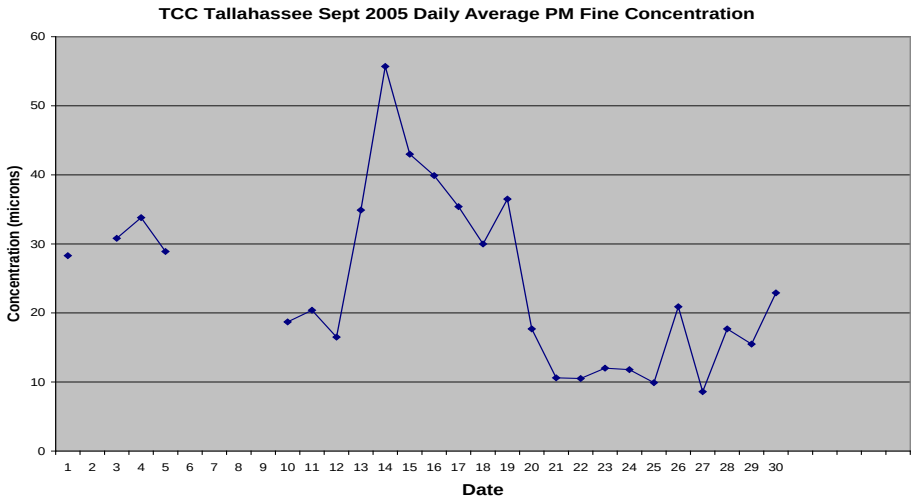

Figure 18. Tallahassee Community College PM fine monitor September 2005.

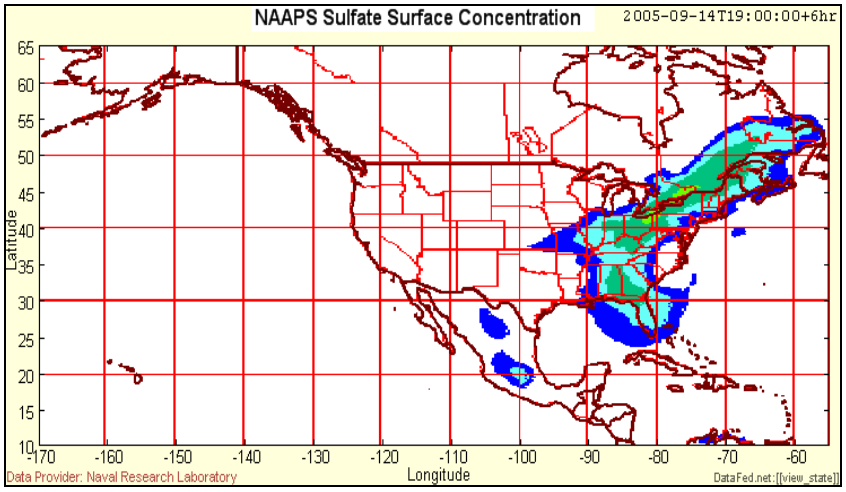

Figure 19. Sulfate Event from September 14, 2005

7.4. Project Ambient Air Quality Impact Analysis

In conducting an ambient air quality impact modeling analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate AAQS to ensure that the proposed project will not cause or contribute to a violation of an AAQS.

A combination of fence line, and non-fence line receptors were chosen for predicting maximum concentrations in the vicinity of the project. The receptor grid consisted of receptors spaced at 50 meter (m) intervals around the facility fence line. The remaining receptors were spaced at 100 m intervals from the property boundary out to 2 km, and 250m spacing from 2 km to 4 km. In addition, receptors were placed 50 km away from the facility to evaluate possible impacts at the Class I St. Marks National Wilderness Area and the Bradwell Bay National Wilderness Area.

Models and Meteorological Data Used in the Ambient Air Quality Analysis

The AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project. AERMOD was approved by the EPA in November 2005. The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including the treatment of both surface and elevated sources, and both simple and complex terrain. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor.

A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

The AERMET meteorological data used for this analysis consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the Apalachicola Municipal Airport and the Tallahassee Regional Airport respectively. The 5-year period of meteorological data was from 2001 through 2005. The meteorological data used were in accordance with the EPA AERMOD Implementation Guide.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification should EPA revise the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators. A more detailed discussion of the required analyses follows.

AAQS Analysis

A modeling analysis was completed to show compliance with the AAQS. The total impact on ambient air quality is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The maximum predicted annual and high, second high short term impacts for the AAQS analysis are summarized in Table 14 below. As shown in this table, emissions from the proposed facility are not expected to significantly cause or contribute to a violation of an AAQS.

The results of the Ambient Air Quality Analysis show that the proposed project will not cause or contribute to a violation of an AAQS. The applicant also provided modeling results for PM_{10} including other sources of PM_{10} in the vicinity of the project to further ensure compliance with the AAQS. These results were also below the AAQS.

As stated above, the applicant completed a modeling analysis placing receptors at 50 km away from the proposed project in the direction of the respective Class I area to evaluate possible impacts at the Class I St. Marks National Wilderness Area and the Bradwell Bay National Wilderness Area. The results were compared to the stringent Class I Significant Impact Levels. These levels are the threshold for which additional multi-source modeling would be required.

Table 14. - Ambient Air Quality Impacts.

Pollutant	Averaging Time	NWFREC Impact ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater Than AAQS?	Florida AAQS ($\mu g/m^3$)
PM_{10}	24-hour	17	61	78	NO	150
	Annual	4	22	26	NO	50
NO_2	Annual	1	9	10	NO	100
SO_2	3-hour	4	267	271	NO	1,300
	24-hour	3	39	42	NO	260
	Annual	0.2	5	5	NO	60
CO	1-hour	18	10,350	10,368	NO	40,000
	8-hour	26	3,450	3,476	NO	10,000

Table 15 below show the results of this analysis. The conclusion is that the proposed project impacts are less than significant.

Table 15. Class I Area Impacts

Class I Area	Pollutant	Averaging Time	Maximum Concentration	Class I SIL
Bradwell Bay	SO_2	Annual	0.001	0.1
		24-hour	0.031	0.2
		3-hour	0.140	1
	PM_{10}	Annual	0.002	0.2
		24-hour	0.08	0.3
	NO_2	Annual	0.01	0.1
St Marks	SO_2	Annual	0.001	0.1
		24-hour	0.025	0.2
		3-hour	0.142	1
	PM_{10}	Annual	0.002	0.2
		24-hour	0.07	0.3
	NO_2	Annual	0.02	0.1

Conclusion regarding Air Quality

Emissions from the proposed project are less than the significant emissions rates (SER) for each PSD-pollutant. Based on the fact that the project does not trigger PSD, the present ambient air monitoring concentrations and the regional nature of pollution events affecting the area, the Department concludes that this project will not cause or contribute to a violation of a National Ambient Air Quality Standard.

8. CONCLUSION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution control regulations as conditioned by the Draft Permit.

[1] Article. Farina, G.L. and Bressan, L. "Optimizing IGCC Design." Foster Wheeler Review. 1999.

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[3] Paper. Paisley, et al. FERCO, NREL, BED, Battelle. The Biomass Gasification Process by Battelle/FERCO: Design, Engineering, Construction and Startup. Gasification Technologies Council Annual Conference. 1998.

[4] Paper. Paisley, et al. FERCO, NREL, BED. "Preliminary Operating Results from the Battelle/FERCO Gasification Demonstration Plant in Burlington, Vermont, U.S.A." The 1st World Conference and Technology Exhibition on Biomass for Energy and Industry. Seville. June 2000.

[5] Report. Boerrigter, H. et. al. ERCN, Dahlman. "OLGA Tar Removal TechnologyProof-of-Concept for application in integrated biomass gasification combined heat and power systems." 2005.

[6] Paper. Könemann, H.W.J. and van Paasen, S.V.B. ERCN, Dahlman. "OLGA Tar Removal Technology4 MW Commercial Demonstration." Berlin. November, 2007.