TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Northwest Florida Renewable Energy Center, LLC

Nominal 55 Megawatts Biomass Gasification Combined Cycle Unit

Gulf County

DEP File No. 0450012-002-AC

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

April 27, 2011

1. APPLICATION INFORMATION

1.1. Applicant Name and Address

Northwest Florida Renewable Energy Center (NWFREC), LLC
1331 17th Street, Suite 720
Denver Colorado 80202

***Authorized Representative*:** Mr. John H. Diesch

1.2. Processing Schedule

February 1, 2011:	Received air construction permit application. Link to NWFREC Project Site .
February 17	Applicant published Notice of Application in The Star - Port St. Joe.
February 21	Department sent request for additional information (RAI) to the applicant.
March 14	Department received response to RAI .
March 31	Department received supplemental information .
April 22	Department received updated Owner/Authorized Representative Statement .
April 27	Department distributed Intent to Issue Air Permit.

1.3. Facility Location

The proposed 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. Earlier Artist Rendition of NWFREC.

Figure 2 is an early artist rendition of the proposed facility. The biomass will be delivered by trucks although the graphic shows options for future rail and barge delivery. 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. Project Description

The applicant proposes to construct a biomass gasification combined cycle (BGCC) unit and auxiliary equipment. The main BGCC unit components will be:

- A biomass receiving, handling, storage and drying system;
- One biomass circulating fluidized bed (CFB) gasifier that yields biomass product gas (BPG);

- One CFB char combustor and stack;
- A BPG flare/thermal oxidizer (TO) system;
- A BPG cleanup system;
- Two cooling towers;
- Three BPG fueled SOLAR T-130 combustion turbine-electrical generators (CTG) or a single, larger BPG fueled General Electric (GE) MS6001B CTG;
- One heat recovery steam generator (HRSG) and stack for each CTG;
- A steam turbine-electrical generator (STG);
- An auxiliary boiler; and
- Two emergency equipment engines (generator and fire pump).

Table 1 indicates the emissions units (EU) comprising the project.

Table 1. EU Identified for the NWFREC

ID No.	Emission Unit Description
001	Biomass handling, storage and drying system
002	Biomass gasifier with natural gas (NG) startup burner
003	Char combustor sand heater with NG startup burner and sand handling equipment
004	BPG Cleanup System and Flare/TO System
005	Compressor and STG cooling towers
006	Auxiliary boiler with a maximum heat input rate of 62 mmBtu/hour from firing NG
007	500 kilowatt (kW) emergency generator firing ultra low sulfur distillate (ULSD) fuel oil containing 0.0015% sulfur or less or biodiesel
008	250 kW emergency fire water pump firing ULSD fuel oil or biodiesel
009	One SOLAR T-130 or one GE MS6001B BPG-fueled CTG and HRSG
010	One SOLAR T-130 BPG-fueled CTG and HRSG
011	One SOLAR T-130 BPG-fueled CTG and HRSG

The process will consume approximately 1,285 wet tons per day (TPD) of biomass or approximately 900 dry (23pecent moisture content) TPD. The CTG and the STG will produce approximately 47 megawatt (MW) and 19 MW, respectively, for a total of 66 MW on gross basis (MWgross) at the reference temperature of 55 degrees Fahrenheit (^{o}F). After accounting for a parasitic load of approximately 11 MW to operate the plant, approximately 55 MW will be delivered to the electrical grid (MWnet).

2. PROCESS DESCRIPTION

BGCC involves the pyrolysis of biomass fuel in an oxygen (O_2) starved (reducing) atmosphere and then combustion of the resultant BPG, char and tars in an oxidizing atmosphere with associated heat recovery, steam generation, and electrical power production. The pollution control measures and equipment for the main process components will consist of Good Combustion Practices (GCP), an ammonia (NH_3)-based selective non-catalytic reduction (SNCR) and a fabric filter (FF) baghouse for the char combustor. The BPG will be cleaned of solids, tars and inorganic impurities prior to combustion in the CTG. The exhaust from the CTG/HRSG will pass through an oxidation catalyst (ox-cat) and an NH_3-based selective catalytic reduction (SCR) system prior to exhausting through the stack(s).

Figure 3 is a simplified process flow diagram of the BGCC including some of the key air pollution control equipment. Details are provided further below.

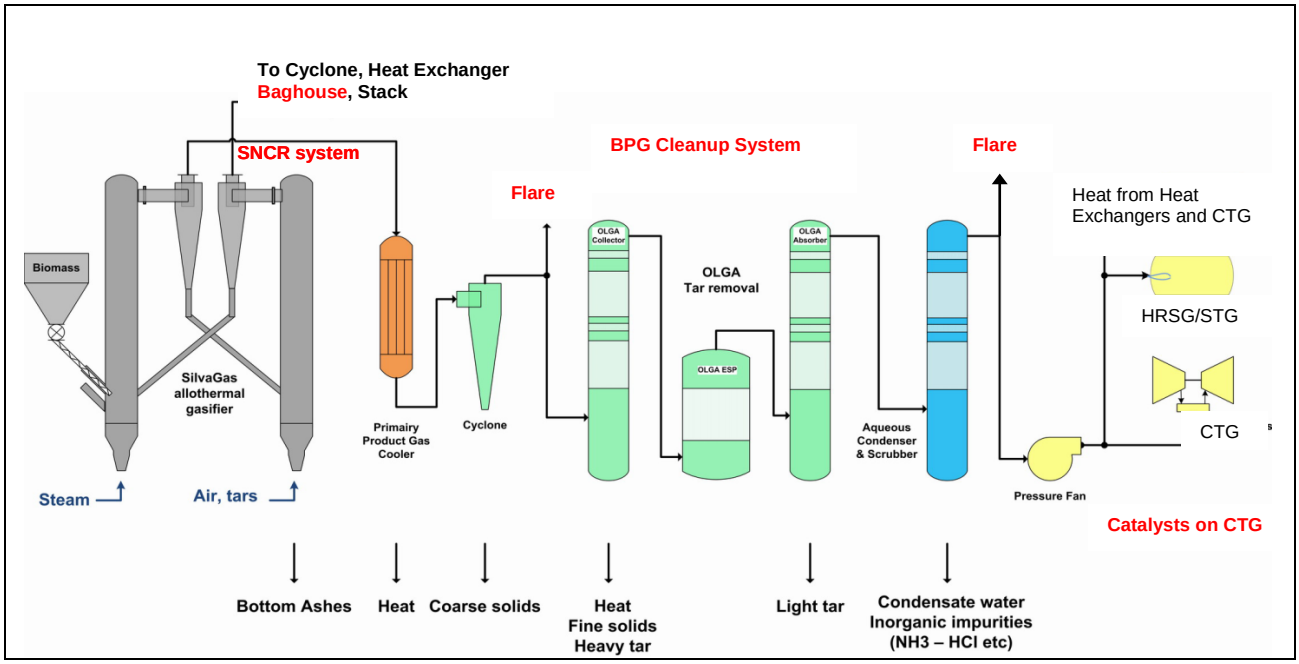


Figure 3. Simplified BGCC Process Diagram including Key Air Pollution Control Systems.

2.1. <u>(EU 001) Fuel Receiving, Storage, Handling, and Drying System</u>

Fuel

The biomass 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. Table 2 is a listing of the broad classifications of feedstock types identified by the applicant.

Table 2. Summary of Woody Biomass Fuel Descriptions.

Fuel Group	Description
Pine Trees	Wood chips from slash, sand and loblolly pine trees
Saw Dust	Saw dust 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 such as arundo donax or eucalyptus
Yard Waste	Grass, grass clippings, bushes, shrubs, and clippings from bushes and shrubs that are generated by residential, commercial/retail, institutional, and/or industrial sources as part of maintenance activities associated with yards or other private or public lands.

A more specific listing of the actual fuels approved for use is provided in the draft permit and the Best Management Practices (BMP) Plan included in the appendices to the draft permit.

Biomass Stackout

All woody biomass will be delivered to the site via truck. The fuel storage pile will contain 12 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 similar to the one shown in Figure 4.

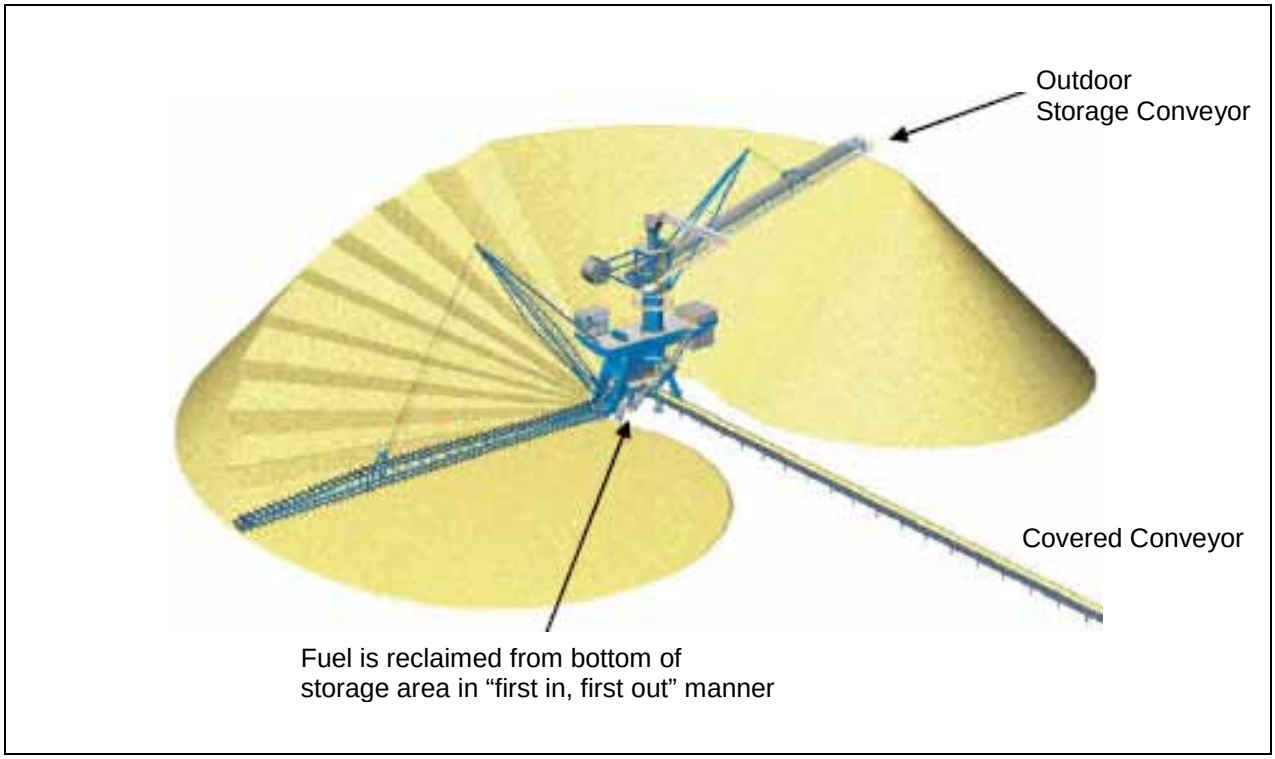


Figure 4. Layout of Kidney-Shaped Pile Operating on Principle of First In/First Out.

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 (FIFO). 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 FIFO, such operation will minimize dust generation, biological degradation, odors and the chance of spontaneous combustion.

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 5 below.

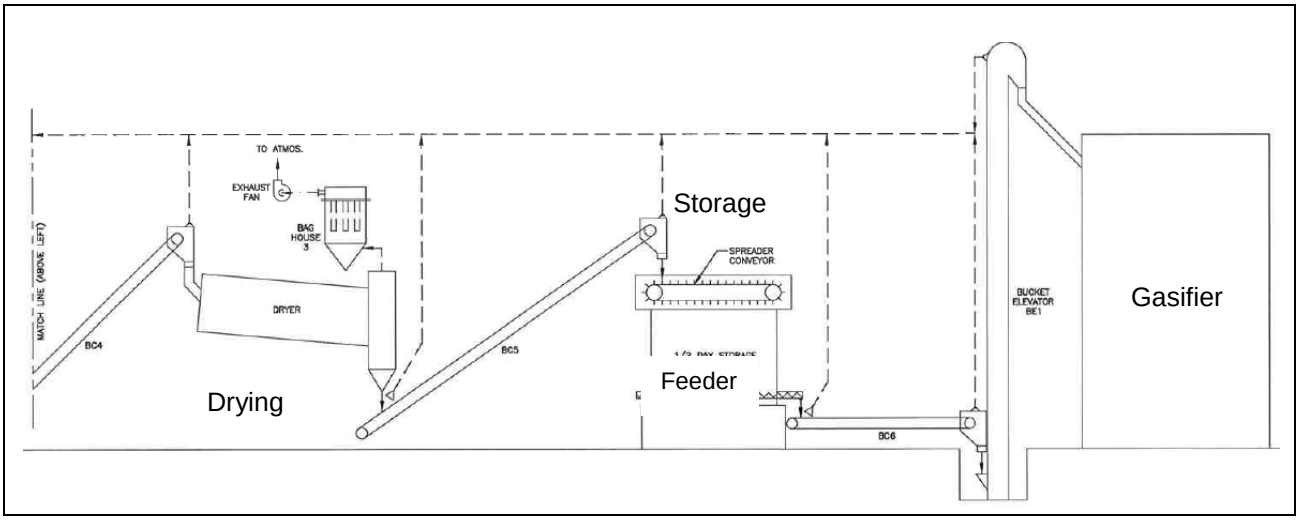


Figure 5. Woody Biomass Drying, Conveyance and Feeding to Gasifier.

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. Covered belt conveyors will transport the feedstock to a 12-hour storage silo (day bin) adjacent to the gasifier. The belt conveyors will be equipped with belt covers to protect the material from the weather and to prevent the wind from blowing material off of the conveyor belt during transport to the storage silo. Material will be reclaimed from the storage silo via an internal screw discharger, which will deposit the material on a belt conveyor contained primarily inside the silo structure. This belt conveyor will transfer the wood fuel to a vertical elevator that will discharge the fuel via an enclosed chute system to the gasifier fuel feed bin. Approximately 900 dry 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 metering bin.

2.2. <u>(EU 002) Gasifier with Startup Burner</u>

The SilvaGas gasification system consists of two main vessels with cyclones and natural gas burners as shown in Figure 6. The large vessel on the left hand side is the <u>gasifier</u>.

The initial startup of the gasifier will utilize a blower to force air into the gasifier. One hour later, a 25 million Btu per hour (mmBtu/hr) natural gas fired burner will be started. The burner will fire for approximately 12 hours. During this time, the sand (olivine) in the CFB will be heated to the bed operating temperature 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 approximately one hour, the woody biomass feed rate will be gradually increased to steady state conditions.

Biomass is fed into the CFB gasifier where it is heated in a bed of hot fluidized sand. During the process, steam is introduced, the sand cools and the biomass feed breaks down by the process of pyrolysis in the absence of O_2 to produce BPG, char, ash and condensable organic compounds referred to as “tar”.

The gasification proceeds as follows:

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

$C_aH_bN_cO_dS_eX_f + H_2O + hot\ sand \rightarrow CO, H_2, CH_4, N_2, NH_3, H_2S, HCl, char, tars, ash, cooled\ sand$

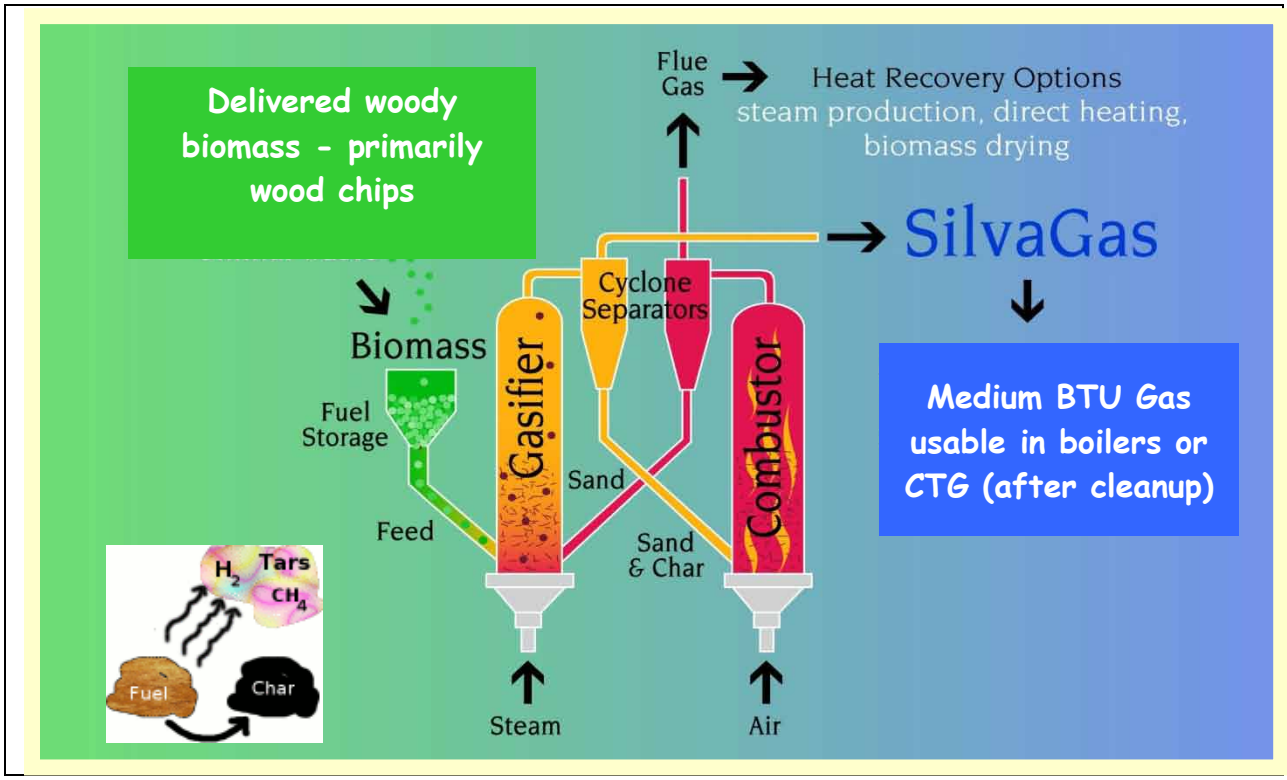


Figure 6. Gasifier/Combustor Section of the SilvaGas Process and Exhaust streams.

The species on the far left of **Equation 1** represents the biomass and steam (H_2O). The subscripts (a, b, etc.) on the left are variable depending on the type of fuel. "X" represents miscellaneous atoms. The molecular gasification products on the right are primarily carbon monoxide (CO), hydrogen (H_2), methane (CH_4), molecular nitrogen (N_2), ammonia (NH_3), hydrogen sulfide (H_2S) and hydrogen chloride (HCl). Figure 7 is an approximate representation of biomass pyrolysis taken from a National Environmental Research Laboratory (NREL) document.

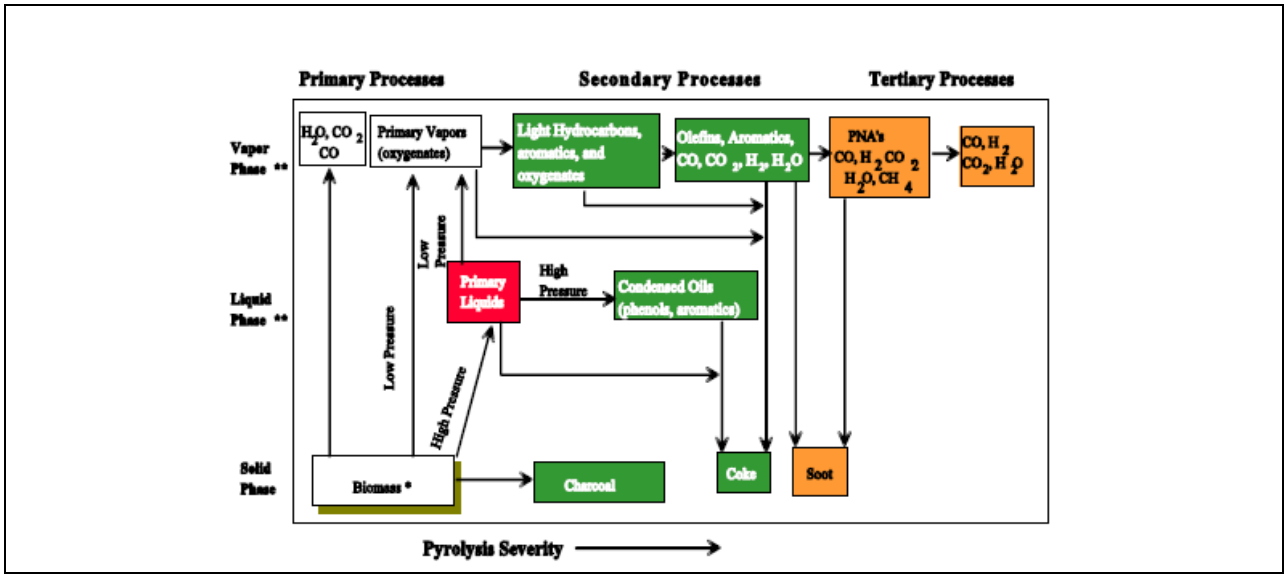


Figure 7. Pyrolysis Pathways.

"Pyrolysis severity" is, roughly speaking, dependent upon temperature, extent of O_2 starvation, time in the gasifier, steam to biomass ratio, etc. The document is available at:

http://www.nrel.gov/docs/fy99osti/25357.pdf .

BPG from the gasifier, including tars and fine ash, is subsequently treated in the BPG Cleanup System (EU 004) prior to combustion in the CTG (EU 009 to 011) as discussed further below. Tars contained in the BPG are difficult to define in a precise manner. One working definition is given in the NREL document as follows: "*the organics produced under thermal or partial-oxidation regimes (gasification) of any organic material are called "tars" and are generally assumed to be largely aromatic"* (i.e. cyclic hydrocarbons). The ash is primarily mineral inorganic particulate matter (PM).

The char is rich in carbon (C). Much of the char and entrained sand from the gasifier is captured in cyclone separator on the left hand side and fed to char combustor (EU 003).

2.3. (EU 003) Char Combustor with Startup Burner

The large vessel on the right in Figure 6 above is the CFB char combustor in which the char and tars returned from the BPG cleanup system (EU 004) are combusted in or above a bed of sand.

Equation 2: 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, SO_2, N_2, H_2O, *char, ash, hot sand*

The applicant estimates that approximately 5.3 TPH of char along with tar from the BPG gas cleanup system will be fed to the combustor. Make up sand must be added to the process at an estimated rate of 300 pounds per day (lb/day). 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 be exhausted to the atmosphere. Char combustor exhaust gas will contain very little sulfur dioxide (SO_2) because most sulfur (S) leaves the gasifier as H_2S in the raw BPG. Further SO_2 control is not required from the combustor exhaust gas.

Similarly, most of the reduced 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. The previously mentioned SNCR system will be installed between the combustor and the baghouse as indicated in Figure 3 above and used to the extent necessary to control NO_X emissions to the permitted limit as follows:

Equation 3. NH_3 reacts with NO_X in the presence of excess O_2 according to the following simplified reaction:

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

The applicant's estimate of annual emissions from the char combustor and other EU are given in Table 5 below.

The European Center of the Netherlands (ECN) conducted an evaluation of possible dioxin emissions from the project, in particular from the char combustor, and estimated that there will be less than 0.1 nanograms, International Toxic Equivalent per normal cubic meter (ng I-TEQ/nm^3). The low value is achieved by using biomass with low chlorine and low ash while maintaining sufficiently long residence time and temperature in the char combustor. Their presentation to the Tallahassee Scientific Society (TSS) is attached to their RAI response dated March 14, 2011 and is available at the ECN website at: www.ecn.nl/docs/library/report/2009/l09126.pdf

2.4. (EU 004) BPG Cleanup System and Flare/TO System

BPG Coarse Solids Removal, Cyclone

The raw BPG and the entrained ash and tars that are 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 (located immediately upstream of the cleanup up equipment) where coarse particles are removed as shown in Figure 3. The BPG is further cleaned for use in the CTG. There will be provisions for flaring or combusting the BPG following coarse solids removal or following cleanup as discussed below. The applicant may rely on TO (burning in a combustion chamber to which air is directly provided) instead of flaring (where the BPG is combined with air at the tip).

BPG Tar Removal, OLGA System

The raw BPG is treated for removal of tars. The key BPG cleanup system shown in Figure 3 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. Information regarding OLGA is available from the ECN and the commercial developer, Dahlman at the following links:

Link to ECN OLGA and Link to Dahlman OLGA

The BPG will be further treated as described below and the tars will be recycled to the combustor as previously described.

BPG Inorganic Impurities Removal, Condensation and Scrubbing

Before combusting the BPG in the CTG it is still necessary to reduce the relatively small amounts of NH_3, H_2S and HCl contained in the treated BPG from the OLGA system. The removal will be accomplished in an aqueous condenser and 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).

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

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

Normally, elemental (Hg^0) is not readily removed by scrubbing with water. However, according to the applicant, Hg^0 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 and disposed.

BPG will leave the cleanup system at approximately 110 °F and 10 pounds per square inch, gauge pressure (psig). The Sweetened, cleaned BPG will then be pressurized in a three-stage BPG compressor and delivered to the CTG. The characteristics of the BPG are given in Table 3.

Table 3. Typical BPG Composition from Silva Gas Process.

Constituent	Product Gas Composition (% by Volume)
H_2	20.7
CO	45.8
CH_4	15.6
Carbon dioxide (CO_2)	11.0
Ethylene (C_2H_4)	5.3
Ethane (C_2H_6)	0.7
H_2O	0.2
N_2	0.7
H_2S	0.02
Lower Heating Value (LHV)	435 Btu/scf

The cleaned BPG can be described as medium heating value fuel of ~435million British thermal units per standard cubic feet (mmBtu/scf) on a lower heating value (LHV) basis. For comparison NG typically has a heating value of 1,050 mmBtu/scf.

BPG Flare/TO System

One flare/TO will be included after the coarse cyclone separator and before the OLGA system as indicated in Figure 3. It will be capable of flaring/combusting raw BPG. The other flare/TO, also shown in Figure 3, will be installed immediately after the aqueous condenser and scrubber. It is possible that a single flare/TO can accomplish both purposes and this will be a detail further developed in the design phase.

The flares/TO provide means for emergency venting and will operate under three conditions. These are startup, planned shutdowns and emergency shutdowns (i.e., in the event of a gasifier trip). The flare/TO system is provided with flare pilots fueled by NG. The two flares/TO provide a stable environment to burn the gas produced during process upsets.

During most of the startup time, no biomass is fed and the gas startup burners will be in operation. Therefore, the BPG flares/TO are not required during this time. The flares/TO are the only pollutant emitters within the BPG cleanup system.

2.5. (EU 005) Cooling Towers

Water will be drawn from the freshwater canal from the Chipola River that presently terminates at the Port St. Joe Water Treatment Plant (WTP) located within one mile south of the proposed NWFREC. The canal should not be confused with the more brackish and much wider parallel canal that runs along the north of the proposed site and discharges into St. Joseph's Bay. The cooling towers will use a combination of water from the described source and possibly some reclaimed water from the adjacent wastewater treatment plant (WWTP). Blowdown water from the cooling towers will be conveyed to the WWTP. Only PM emissions as controlled by permitted drift rates are addressed in the air permit.

Compressor Gas Cooling Tower

A conventional cooling tower will be used to cool compressor gases. The cooling water is sprayed at the rate of 3,800 gallons per minute (gpm) onto surfaces in the tower and cooled by evaporation of air drawn across the surfaces. The water is then used in a heat exchanger to cool or condense the fluid.

Steam Turbine Condenser Cooling Tower

The wet surface air condenser cooling tower serving the STG works on a different principle whereby spray water and air are introduced on the outside of tube bundles that contain the water required for cooling. Heat is transferred from the inside of the tubes to the water film on the outside of the tubes. The film is subsequently evaporated and the heat exits through tower exhaust slots.

The steam tube condenser requires approximately 7,050 gpm of water and will be designed for a low drift rate of 0.002%.

2.6. (EU 006) Auxiliary Boiler

A NG fueled auxiliary boiler with a nominal capacity of 62 mmBtu per hour (mmBtu/hr) will be included in the project for the purpose of providing steam as the conveyance medium for the sand in the gasifier and to heat the sand to approximately 800 °F during startup. It will also provide steam to preheat the STG during startup.

2.7. (EU 007) Emergency Generator

The project will include a nominal 500 kW emergency firewater pump fueled with biodiesel or ULSD fuel oil. Operation of this unit will be limited to no more than 500 hours per year (hr/yr).

2.8. (EU 008) Emergency Firewater Pump

The project will include a nominal 250 kW emergency fire water pump engine fueled with biodiesel or ULSD fuel oil. Operation of this unit will be limited to no more than 250 hr/yr.

2.9. (EU 009 - 011) CTG with HRSG

CTG and Combined Cycle Description

Refer to Figures 8 and 9. Per the original application, the applicant proposes to use three 16 MW SOLAR T-130 CTG. Ambient air is filtered, chilled and compressed. The compressed air is directed to the combustors where the fuel from the BPG compressor is introduced, ignited, and burned. The hot combustion gases are diluted with cooling air from the compressor and directed to the rotor (expansion) section of the CTG.

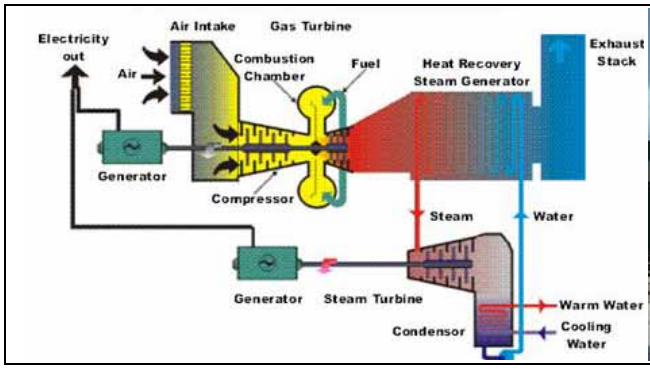


Figure 8. How a Combined Cycle Works. **Figure 9. Picture of a SOLAR T-130 CTG**

Energy is recovered in the rotor section in the form of shaft horsepower, which drive the main compressor section and an electrical generator. Hot turbine exhaust gas (TEG) is directed to the HRSG, where the waste heat is used to raise steam. The steam is used in the STG for additional production of electricity.

The alternative design is based on a single but larger GE MS6001B CTG. Details regarding the models of CTG for the project are available at: Link to SOLAR T-130 CTG and Link to GE MS6001B CTG .

Air Pollution Controls for the CTG

Air pollution controls for either CTG option are listed below.

- SO_2 and HCl are limited by use of woody biomass and by removal of H_2S and HCl through caustic scrubbing of the BPG as described above.
- PM/PM_{10} will be removed from the BPG by the gasifier cyclones, fine solids removal in the BPG cleanup system and high temperature combustion in the CTG.
- NO_X formation is limited by: removal of nitrogen compounds such as ammonia (NH_3) in the water scrubber prior to combustion of the BPG; water or steam injection into the combustors to control thermal NO_X formation; and SCR (similar to SNCR but with a catalyst) in the HRSG after combustion.
- CO and VOC will be controlled by high temperature combustion and an oxidation catalyst system in the HRSG after combustion.
- Formation of Dioxin /Furan (D/F) is limited by: relatively low chloride in woody biomass; removal of tar from BPG; scrubbing of HCl prior to combustion in the CTG; and further oxidation by SCR and oxidation catalyst in the HRSG after combustion in the CTG. Because of the catalysts, D/F emissions from the CTG will be less than projected by ECN in the previously mentioned presentation to the Tallahassee Scientific Society.

The effectiveness oxidation catalyst in the conversion of CH_2O and CO (if not already destroyed in the CTG) can be appreciated by the curves in Figure 10. Even in a relatively low temperature environment (500 ^oF) these compounds and many other VOC and HAP are largely destroyed. The SCR catalyst which will follow the ox-cat would further destroy a high percentage of the remaining VOC and HAP.

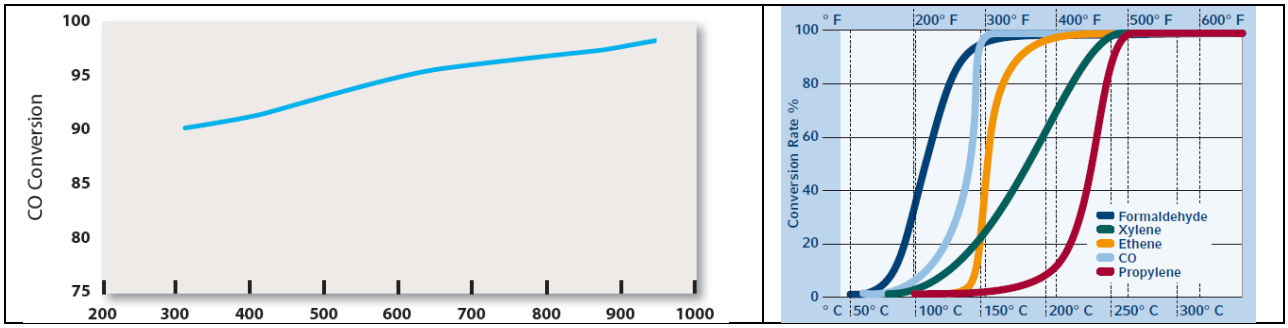


Figure 10. Ox-cat Performance in CO, CH_2O and certain VOC and vs. Temperature (^oF and ^oC)

3. APPLICABLE REGULATIONS

3.1. State Regulations

This project is subject to the applicable environmental laws specified in Chapter 403 of the Florida Statutes (F.S.). The F.S. authorizes the Department of Environmental Protection (Department) to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). State regulations approved by EPA are given in 40 CFR Part 52, Subpart K – Florida, also known as the State Implementation Plan (SIP) for Florida. This project is subject to the applicable rules and regulations defined in the following Chapters of the F.A.C. and summarized in Table 4.

Table 4 - Applicable Rules from the F.A.C.

F.A.C. Rule	Description
62-4	Permits
62-204	Air Pollution Control – General Provisions
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Stationary Sources – Preconstruction Review
62-213	Operation Permits for Major Sources (Title V) of Air Pollution
62-214	Requirements for Sources Subject to the Federal (Title IV) Acid Rain Program
62-296	Stationary Sources – Emission Standards
62-297	Stationary Sources – Emissions Monitoring

3.2. Federal Regulations

The U.S. Environmental Protection Agency (EPA) establishes air quality regulations in 40 Code of Federal Regulations (CFR) Part 60 that identifies New Source Performance Standards (NSPS) for a variety of industrial activities. 40 CFR Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP). 40 CFR Part 63 specifies NESHAP provisions based on the Maximum Achievable Control Technology (MACT) for given source categories.

The Federal NSPS and NESHAP regulations are adopted by reference in the State regulations and are given in Rule 62-204.800, F.A.C. State regulations approved by EPA are given in 40 CFR Part 52, Subpart K – Florida, also known as the State Implementation Plan (SIP) for Florida. Link to Subpart K .

3.3. Potential Emissions and PSD Non-Applicability Determination

The following table is a listing of applicant's estimates of annual emissions of key pollutants from the project. A listing of emission estimates by the applicant on a pound per hour (lb/hr) basis, along with the emission limits in the draft permit is included as Attachment 1 to this evaluation.

Table 5. Applicant's Estimate of Annual Emissions from the NWFREC in TPY.

Pollutant [1]	CTG	Char Combustor	Cooling Towers	Material Handling [2]	Aux. Boiler	Flares TO	Emergency Equipment	Total
SO_2	11.9	59.1	0	0	0.09	3.64	negligible	74.73
PM	61.6	2.5	1.03	12.5	0.03	neg	0.07	77.73
PM_{10}	61.6	2.5	0.73	7.0	0.03	neg	0.07	71.93
NO_X	118.1	42.0	0	0	1.47	3.18	1.24	165.99
CO	72.3	67.7	0	0	1.24	17.34	1.24	159.82
VOC	13.7	7.0	negligible	0	0.08	6.56	0.15	27.49
SAM [3]	1.2	5.9	negligible [4]					7.1
HAP	5.8	5.2	negligible					11.0
Hg	Neg.	6 lb/yr	negligible					6 lb/yr
NH_3 [5]	5.2	3.4	negligible					8.6
F [6]	negligible							~0
Pb	negligible							~0

1. Pollutants listed above are PSD-pollutants except HAP and Hg.
2. Includes emission from biomass dryer.
3. SAM - sulfuric acid mist. The Department estimated SAM = 10% of SO_2 emissions.
4. Negligible (Neg.) means zero (0) or that it does not affect the last significant figure in the estimate.
5. Emissions of NH_3 are primarily from "slip" of reagent used in the SCR and SNCR NO_X control systems.
6. F – fluoride.

The Department regulates major stationary (PSD) sources in accordance with Florida's PSD program pursuant to Rule 62-212.400, F.A.C. However, the project is not a major stationary (PSD) source as explained in accordance with the explanation that follows:

As defined in Rule 62-210.200(189), F.A.C., a "major stationary source" (subject to PSD) is:

1. Any of the following stationary sources (commonly known as the "list of 28") of air pollutants which emits, or has the potential to emit (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 acid plants,
   - Sulfuric acid plants,
   - 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 BGCC is not among the bulleted stationary sources listed in paragraph 1. The NWFREC will be neither a fossil fuel-fired steam electric plant (FFFSEP) nor does it include a fossil-fueled boiler (FFB). Every meaningful aspect of its design is purposefully directed to the gasification of wood and combustion of the resulting BPG, char and tar to make steam in order to generate power.

The Department reviewed the 2011 filing of Progress Energy to the PSC describing its 10-year Site Plan. The plans of the key utilities are available at: www.psc.state.fl.us/utilities/electricgas/10yrsiteplans.aspx .

The Progress Energy submittal is at: http://www.psc.state.fl.us/library/filings/11/02134-11/02134-11.pdf .

According to the submittal, Progress Energy has a renewable energy contract to take 45 MW of the electrical generation from the project. Wood biomass is not a fossil fuel. If the project were actually a FFFSEP, it would not meet the renewable energy contract requirements or qualify for the U.S. Treasury considerations. The use of natural or fuel oil to start up or even to stabilize the process would not make it a FFFSEP.

The PTE of each PSD pollutant from the NWFREC is less than 250 TPY and is not subject to paragraph 2. The proposed NWFREC is not an existing stationary source and not subject to paragraph 3.

Therefore, the NWFREC is a minor source and not subject to the PSD rules including PSD ambient air modeling and the requirement for a BACT determination.

3.4. Major Source of Air Pollution (Title V Source) Determination

As defined in Rule 62-210.200(188), F.A.C., a Title V source is an emissions unit or group of emissions units that directly emits, or has a PTE of, 100 TPY or more of any regulated air pollutant. The Major (Title V) Source of Air Pollution definition also includes, any emissions unit or group of emissions units that (except for radionuclides) emits or has the PTE of, in the aggregate, 10 tons TPY or more of any one HAP, 25 TPY or more of any combination of HAP, or any lesser quantity of a HAP as established through EPA rulemaking. Specific HAP are defined/listed in Rule 62-210.200(155), F.A.C.

The emissions estimates given in Table 5 above are sufficient to conclude that the NWFREC facility will be a Title V source based on emissions of regulated air pollutants regardless of HAP emissions.

3.5. HAP Major Source Determination

As defined in 40 CFR 63, Subpart A, adopted and referenced in Rule 62-204.800(11)(d)1, F.A.C., and per Rule 62-210.200(188 – Major Source of Air Pollution), F.A.C., a major source of HAP means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the PTE of, considering controls, in the aggregate, 10 TPY or more of any HAP or 25 TPY or more of any combination of HAP, unless the Administrator establishes a lesser quantity, or in the case of radionuclides, different criteria from those specified in this sentence. See Link to Subpart A

Table 5 above includes the applicant's estimate of HAP from the key emission categories at the NWFREC facility. Facility HAP emissions are estimated at less than 25 TPY in the aggregate. According to the application, an estimated 5.8 TPY of HAP will be emitted from the CTG of which 5.3 TPY will be as formaldehyde (CH_2O). Of the estimated 5.2 TPY of HAP emitted from the char combustor, 3.0 TPY will be as naphthalene. The PTE of no single HAP from the facility is equal to or greater than 10 TPY.

Although the NWFREC is a Major (Title V) Source of Air Pollution it is not a Major Source of HAP. It is an area source of HAP. Note: Title V are requirements under a separate agency action once the NWFREC becomes operational.

3.6. Rule Applicability Summary

Following is a summary of the applicability of key regulations for the NWFREC project.

Chapter 62-4, F.A.C.

Rule 62-4.070, F.A.C., Standards for Issuing or Denying Permits; Issuance; Denial.

This rule applies to all permitting decisions:

- (1) A permit shall be issued to the applicant upon such conditions as the Department may direct, only if the applicant affirmatively provides the Department with reasonable assurance based on plans, test results, installation of pollution control equipment, or other information, that the construction, expansion, modification, operation, or activity of the installation will not discharge, emit, or cause pollution in contravention of Department standards or rules.
- (3) The Department may issue any permit with specific conditions necessary to provide reasonable assurance that Department rules can be met.

Chapter 62-17, F.A.C.

Electrical Power Plant Siting

- In accordance with section 403.506, F.S., the provisions of this rule do not apply to this project or any electrical power plant of less than 75 MW in gross capacity, unless the applicant has elected to apply for certification of such electrical power plant under this act. Link to Section 403.506, F.S.

Chapter 62-204, F.A.C.

Rule 62-204.220(1), F.A.C., Ambient Air Quality Protection.

This rule applies to all air permitting decisions.

- The Department shall not issue an air permit authorizing a person to build, erect, construct, or implant any new emissions unit; operate, modify, or rebuild any existing emissions unit; or by any other means release or take action which would result in the release of an air pollutant into the atmosphere which would cause or contribute to a violation of an ambient air quality standard established under Rule 62-204.240, F.A.C.

Rule 62-204.240, F.A.C., Ambient Air Quality Standards.

This rule applies to all air permitting decisions.

- Refer to list of pollutants and ambient air quality standards provided therein and discussed in the Ambient Air Quality Section of this evaluation.

Rule 62-204.800(8), F.A.C., 40 CFR 60, NSPS.

The following Federal regulations incorporated into Rule 62-204.800(8), F.A.C. apply to this project:

- 40 CFR 60, Subpart A – General Provisions which regulates all EU that are subject to a NSPS standard and, in particular, flare pilot flames (EU 004, flares/TO);
- 40 CFR 60, Subpart Db – Industrial-Commercial-Institutional Steam Generating Units - applies to a new steam generating unit with a heat input capacity from fuels of greater than 100 mmBtu/hr that is not subject to 40 CFR 60, Subpart Eb described below (EU 003, char combustor);
- 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (EU 002, gasifier startup burner);
- 40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (EU 007, 008); and
- 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines (EU 009 – 011).

The following Federal regulation incorporated into Rule 62-204.800(8), F.A.C. does not apply to this project for at least the following reason: It is a qualifying small power production facility, as defined in section 3(17)(C) of the Federal Power Act (16 U.S.C. 796(17)(C)).

- 40 CFR 60, Subpart Eb – Large Municipal Solid Waste Combustors for Which Construction is Commenced After September 20, 1984 or for Which Modification or Reconstruction is Commenced After June 19, 1996.

Rule 62-204.800(11), F.A.C., 40 CFR 63, NESHAP.

Per Section 3.9 above, the NWFREC is not a major source of HAP. An area source of HAP means any stationary source of HAP that is not a major source of HAP. The following provisions in Rule 62-204.800(11), F.A.C. adopted from 40 CFR 63 and affecting area sources of HAP apply to this project:

- 40 CFR 63, Subpart A – General Provisions (to the extent explicitly identified within each applicable 40 CFR 63 standard);
- 40 CFR 63, Subpart JJJJJJ - NESHAP for Area Sources: Industrial, Commercial, and Institutional Boilers – applies to enclosed devices using controlled flame combustion in which water is heated to recover thermal energy in the form of steam or hot water (EU 003, char combustor and not EU 006, auxiliary boiler); and
- 40 CFR 63, Subpart ZZZZ - NESHAP for Stationary Reciprocating Internal Combustion Engines (EU 007 and 008). This subpart requires all affected area source units to meet the applicable emission standards of 40 CFR 60, Subpart IIII. 40 CFR 63, Subpart A is explicitly excluded when applying this standard.

The following Federal regulation incorporated into Rule 62-204.800(11), F.A.C. does not apply to this project because the NWFREC is not a major source of HAP:

- 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 types considered for this project.

The project-specific requirements of the applicable NSPS and NESHAP discussed above are provided in Section 4.0 below.

Chapter 62-210, F.A.C.

Rule 62-210.200, F.A.C., Definitions.

- The project is a Title V or "Major Source" of air pollution as discussed in Section 3.4 above.
- The project is an area source and is not a major source of HAP as discussed in Section 3.5 above.
- The project is not a "Major Stationary Source" (PSD-source) as discussed in Section 3.3 above.
- The BGCC is an "Acid Rain Unit" because it is a "utility unit" as defined in 40 CFR Section 72.2, Definitions, does not meet the exemptions provided therein, is subject to 40 CFR 72.6 and thus meets the definition in Rule 62-210.200(8), F.A.C.

Rule 62-210.300, F.A.C., Permits Required.

- Unless exempted, the owner or operator of any facility or emissions unit which emits or can reasonably be expected to emit any air pollutant shall obtain appropriate authorization (i.e. a permit) from the Department prior to undertaking any activity at the facility or emissions unit for which such authorization is required.

Rule 62-210.350, F.A.C. Public Notice and Comment.

- A notice of proposed agency action on permit application, where the proposed agency action is to issue the permit, shall be published by any applicant.

- The additional public notice requirements for emissions units subject to PSD do not apply to this project.

Rule 62-210.700, F.A.C., Excess Emissions.

This rule applies to all air permitting decisions. Only the key provisions potentially affecting this project are listed.

- Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
- Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.
- Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest.

Chapter 62-212, F.A.C.

Rule 62-212.300, F.A.C., General Preconstruction Review Requirements.

- This rule generally applies to the construction or modification of air pollutant emitting facilities in those parts of the state in which the state ambient air quality standards are being met.

Rule 62-212.400, F.A.C., PSD.

- The rule does not apply because the project is not a major stationary (PSD) source.

Chapter 62-213, F.A.C.

- Because the facility is a Title V source, the applicant will be required to apply for and obtain a Title V operation permit in the future.

Chapter 62-214, F.A.C.

The requirements of this chapter apply to the NWFREC because the BGCC is an acid rain unit.

Chapter 62-296, F.A.C.

Rule 62-296.320, F.A.C., General Pollutant Emission Limitation Standards.

- This rule prohibits the discharge of air pollutants which cause or contribute to an objectionable odor;
- This rule specifies a visible emissions standard of 20 percent (%) opacity; and
- The rule prohibits emissions of unconfined PM provisions without taking reasonable precautions to prevent such emissions.

Rule 62-296.401, F.A.C., Incinerators

- The use of small amounts of yard waste does not classify this unit as an incinerator. The Department's definition of "incinerator" at Rule 62-210.200(160), F.A.C. is "a combustion apparatus designed for the ignition and burning of solid, semi-solid, liquid or gaseous combustible wastes". The gasifier is designed to fractionate the woody biomass fuel into two components, namely the BPG and the char. The two components, together with tars recovered from the BPG cleanup equipment are utilized within the same combined cycle unit to produce heat and steam to operate the process and to produce energy. The char combustor is designed to combust the char and tars and the CTG are designed to combust the cleaned BPG. The char, tars and BPG are byproducts of the woody biomass

gasification process and do not constitute solid, semi-solid, liquid or gaseous combustible wastes. Consequently, the gasifier, char combustor and CTG are not considered incinerators.

Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 mmBtu/hr Heat Input

- The NWFREC is a biomass-fuel based steam electric plant not a fossil-fuel plant. Consequently, this rule does not apply.

Rule 62-296.410, F.A.C., Carbonaceous Fuel Burning Equipment

- 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. If applicable, this rule would require that the carbonaceous component of fuel combustion comply with a PM standard of 0.2 lb/mmBtu and a visible emissions (VE) standard of 30% opacity except that 40% opacity is permissible for not more than 2 minutes in any hour. The char combustor will be controlled to lower limits by other applicable standards.

Rule 62-296.416, F.A.C., Waste-to-Energy (WTE) Facilities

- This rule does not apply because per Rule 62-210.200(327), F.A.C., the term "WTE facility" does not include facilities that primarily burn fuels other than solid waste, even if the facility also burns some solid waste as a fuel supplement. The term also does not include facilities that burn vegetative, agricultural, or silvicultural wastes, bagasse, clean dry wood, methane or other landfill gas, wood fuel derived from construction or demolition debris, or waste tires, alone or in combination with fossil fuel. Because of its status (by a federally enforceable permit condition) as a cofired facility in accordance with 40 CFR 60, Subpart Eb, the facility will burn at least 70% fuels "other than solid waste".

Rule 62-296.470, F.A.C., Implementation of Federal Clean Air Interstate Rule (CAIR)

- Use of the larger GE CTG, if selected, would trigger CAIR program requirements. The applicant included a completed CAIR form with the supplemental information submitted on March 31, 2011 in case this CTG is selected.

4. PROJECT SPECIFIC NSPS AND NESHAP REQUIREMENTS

4.1. (EU 002) Gasifier with Startup Burner

The gasifier startup burner will have a nominal rating of 25 mmBtu/hr. The function of this device appears to fit within the definition of a *steam generator unit* as the term is used in NSPS 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."

The gasifier startup burner is subject 40 CFR 60, Subpart A – General Provisions and the only specific requirements that apply for such units are given in CFR 60.48c, Reporting and Recordkeeping Requirements. Links to these subparts are given in Appendices A and Dc of the attached draft permit.

4.2. (EU 003) Char Combustor with Startup Burner

The char combustor startup burner will have a nominal rating of 17 mmBtu/hr. It would be subject to the same reporting requirements as the gasifier startup burner. However such requirements would be subsumed by the more comprehensive requirements on the actual char combustor.

The char combustor is subject to following emission limits given in NSPS 40 CFR 60, Subpart Db and

NESHAP 40 CFR 63, Subpart JJJJJJ which are summarized in Table 6. The requirements for carbonaceous fuel burning equipment (which do not apply to this project) and the applicant's proposed emission limits are included for comparison purposes.

Table 6. Emission Limits for Char Combustor based on Subparts Db and JJJJJJ (lb/mmBtu).

Subpart	PM	Opacity	NO_X	SO_2	CO
40 CFR 60, Subpart Db	0.030	20% [1]	0.30 [2]	Exempt [3]	NA [4]
40 CFR 63, Subpart JJJJJJ	0.030	NA	NA	NA	Work Practices [5]
Rule 62-296.410, F.A.C.	0.2 and 0.1 [6]	30%	NA	NA	NA
Applicant's Proposal	~0.016	5% [7]	~0.062 [8]	~0.087	~0.10 [8]

1. 6-minute block averages as measured continuous opacity monitoring system (COMS) except for one per hour 6-minute block average of 27%.
2. 30-day rolling average as measured by continuous emissions monitor (CEMS).
3. Exempt because uncontrolled emissions are less than or equal to 0.32 lb/mmBtu.
4. NA means not applicable.
5. The permittee shall conduct a tune-up of the char combustor biennially as specified in §63.11223(b).
6. Prorated between carbonaceous and fossil, respectively.
7. Applicant requests excess emissions as provided by Rule 62-210.700, F.A.C. with compliance by COMS.
8. Compliance by CEMS. Control of NO_X by SNCR reagent provides greater flexibility to reduce CO by GCP.

4.3. (EU 004) BPG Cleanup System including Flare/TO System

No NSPS or NESHAP standards are applicable to the BPG cleanup system or flares/TO. Based on Rule 62-4.070, F.A.C., pertaining to reasonable assurance a VE standard has been set for the flare/TO system. The applicant proposed that the flare system meet a VE standard of 20% with a request for excess emissions as provided by Rule 62-210.700, F.A.C. The applicant anticipates that the flare system will operated for 100 hours per year (hr/yr), but did not request a firm operational hour limit. The Department will limit use of the flare/TO system to 200 hr/yr but limit VE to 10%.

4.4. (EU 005) Cooling Towers

No NSPS or NESHAP standards are applicable to cooling towers. To avoid being subject to NESHAP 40 CFR 63, Subpart Q - National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers, use of chromium-based water treatment chemicals in the cooling tower water is prohibited by the permit. The applicant proposed the following type of cooling towers and associated drift rates as described in Table 7 below:

Table 7. Applicant's Proposed Emission Limits Cooling Towers.

Description	Type	Flow Rate (gpm)	Drift (%)
STG Cooling Tower	Wet Surface Air Condenser	~7,050	0.0020
Compressor Gases Cooling Tower	Surface Heat Exchanger	~3,800	0.0050

4.5. (EU 006) Auxiliary Boiler

A NG fueled auxiliary boiler with a nominal capacity of 62 mmBtu/hr is included in the project. The auxiliary boiler is subject to NSPS 40 CFR 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. Specifically, the auxiliary boiler is subject 40 CFR 60, Subpart A – General Provisions and the only specific requirements that apply for such units are given in CFR 60.48c, Reporting and Recordkeeping Requirements. Links to these subparts are given in Appendices A and Dc of the attached draft permit.

No NESHAP is applicable to natural gas-fired boilers located at area sources of HAP.

The auxiliary boiler is subject to the requirements of Rule 62-296.406, F.A.C., which includes a determination of the Best Available Control Technology (BACT) for PM and SO_2 emissions. For this

project, BACT for PM and SO_2 emissions is determine to be the firing of NG with a maximum fuel sulfur content of 2 grains/100 scf as the only authorized fuel.

4.6. (EU 007 and 008) Emergency Generator and Firewater Pump

The project will include a nominal 500 kW emergency generator fueled with biodiesel or ULSD fuel oil. Operation of this unit will be limited to no more than 500 hr/yr. The project will also include a nominal 250 kW emergency fire pump engine with biodiesel or ULSD fuel oil with an operational limit of 200 hr/yr. Both the emergency generator and fire pump engine are subject to NSPS 40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Both the emergency generator and fire pump engine are also subject to NESHAP 40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE). The requirements of Subpart ZZZZ are fulfilled by meeting the requirements of NSPS Subpart IIII.

Tables 8 and 9 include the NSPS Subpart IIII emissions standards for the emergency generator and the emergency fire pump engine.

Table 8. NSPS Subpart IIII – Emission Standards Applicable to Emergency Generator

Emergency Generator (> 450 kW and ≤ 560 kW)	**CO** (g/kW-hr)[1]	**PM** (g/kW-hr)	**SO_2**[2] **(% S)**	**NMHC**[3]**+NO_X** (g/kW-hr)
Subpart IIII (2007 and later)	3.5	0.20	0.0015	4.0

1. g/kW-hr means grams per kilowatt-hour
2. SO_2 emission standard will be met by using biodiesel or ULSD FO in the emergency generator with fuel sulfur (S) content of 0.0015% by weight.
3. NMHC means Non-Methane Hydrocarbons.

Table 9. NSPS Subpart IIII – Emission Standards Applicable to Emergency Pumps

Emergency Pumps (≥ 175 hp and < 750 hp)	**CO** (g/hp-hr)[1]	**PM** (g/hp-hr)	**SO_2**[2] **(% S)**	**NMHC+NO_X** (g/hp-hr)
Subpart IIII (2009 and later)	2.6	0.15	0.0015	3.0

1. g/hp-hr means grams per horsepower-hour.
2. SO_2 emission standard will be met by using biodiesel or ULSD FO in the emergency pump with a fuel sulfur content of 0.0015% by weight.

4.7. (EU 009 - 011) CTG with HRSG

The three 16 MW SOLAR T-130 CTG or the one GE MS6001B CTG are subject to NSPS 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines which applies to CTG constructed after February 18, 2005 and to NSPS 40 CFR 60, Subpart A, General Provisions. The applicable emission limits from Subpart KKKK are given in Table 10 below.

As previously mentioned, NESHAP 40 CFR 63, Subpart YYYY for Stationary Combustion Turbine has been stayed for lean premix and diffusion flame gas-fired CTG including the types considered for this project. Consequently, no NESHAP is applicable to the CTG. The incorporation of an ox-cat as discussed above accomplishes the key goal of the "stayed" CTG NESHAP which was to control emissions of HAP such as CH_2O while achieving very low CO emissions.

Table 10. NO_X Emission Limits for New Stationary Combustion Turbines.

CTG Type	Heat Input (HHV) [1]	NO_X (ppmvd) [2]	SO_2 (lb/mmBtu)
New CTG firing NG	> 50 and ≤ 850 mmBtu/hr	25	0.06
New CTG firing other fuels	> 50 and ≤ 850 mmBtu/hr	74	0.15
SOLAR T-130	~ 160 mmBtu/hr	15 [3]	~ 0.002 [3,4]
GE MS6001B CTG	~ 470 mmBtu/hr	15 [3]	~ 0.002 [3,4]

1. Peak CTG heat input on higher heating value (HHV) basis.
2. Parts per million by volume, dry at 15 percent oxygen on a 30-day basis (ppmvd).
3. Applicant's proposal to comply with NSPS and avoiding PSD threshold of 250 TPY.
4. SO_2 emission limit compliance will be demonstrated by fuel sampling (BPG) and by NG specification.

5. ADDITIONAL HAP DISCUSSION

According to Table 5 above and Attachment 1, emissions from the char combustor (EU 003) and the CTG (EU 009 to 011) comprise more than 90% of the emissions of from the project. The controls described above will ensure compliance with the emission limitations of the applicable NSPS including 40 CFR 60, Subpart Db (char combustor) and 40 CFR 60, Subpart KKKK (CTG). Further, the controls, compliance with the NSPS, draft permit specific conditions and monitoring requirements will, when taken together, insure that no PSD-pollutant will be emitted in an amount equal to or greater than the PSD applicability threshold of 250 TPY. The same measures will also insure that the project will not be a major source of HAP and thus will be an area source.

The char combustor (EU 003) is subject to the 40 CFR 63, Subpart JJJJJJ – Area Source NESHAP. The biomass subcategory applies if a boiler burns at least 15% biomass on a total fuel annual heat input basis. For the purposes of Subpart JJJJJJ, biomass means:

"Any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds."

EPA determined that the Boiler NESHAP for area sources will require MACT emission limits at new coal-fired units for: PM as a surrogate for individual urban metal HAP; CO as a surrogate for individual urban organic HAP; and for Hg. EPA determined that the same NESHAP will require Generally Available Control Technology (GACT) at new biomass-fired units consisting of PM limits and a number of applicable work practices as detailed in 40 CFR 63, Subpart JJJJJJ.

It is worth noting that the earlier proposed version of the Subpart JJJJJJ included a CO limit of 100 ppm at 7% O_2. The applicant has proposed a value of 0.10 lb/mmBtu, which is approximately equal to 94 ppm.

The Department will not impose additional HAP or HAP surrogate limitations on this project. The following sections discuss how Hg and D/F are minimized in this project.

6. STARTUPS AND SHUTDOWNS OF THE GASIFIER ISLAND AND POWER BLOCK

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. Gasification Island Startups

The gasification island consists of the gasifier and the char combustor. The startup sequence for the gasification island is as follows:

- The auxiliary boiler will be started to provide steam as a conveying medium to begin olivine circulation in the gasifier island and to begin heating the gasifier and char combustor to approximately 800 °F. Excess steam from the auxiliary boiler will be used to preheat the STG.
- The blowers to force air into the gasifier and char combustor are started and approximately one hour later the 25 mmBtu/hr (gasifier) and 17 mmBtu/hr (combustor) natural gas fired burners will be started. The burners will fire for approximately 12 hours. The sand bed will be heated to the operating temperature of approximately 1,600 °F and will begin fluidizing.
- At this point the burners will be turned off and woody biomass and steam will begin to be fed into the gasifier.
- Once biomass is fed into the gasifier, the resulting BPG will begin to be sent to the flare/TO system.
- 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.
- During the biomass fed rate ramp up, char from the gasifier is fed to the combustor toward the end of the startup process.
- After the biomass fed rate ramp up is complete, the gasifier blower will be turned off and over the next hour the gasification island should reach steady state conditions. During this period, the BPG is routed to the gas cleanup system and the resulting tars from the gas cleanup system are sent to the char combustor.

6.2. Gasification Island Shutdowns

Two types of gasification island shutdowns will occur, emergency and routine.

Emergency shutdown is defined as total loss or shutdown of incoming electrical power, so that all the process motors stop in a few seconds. Emergency backup electrical power will be available to provide electrical power to the process control system, and a limited number of other electrical users. In general, gas flow through the plant will ramp down rapidly to zero in a space of 3 to 4 minutes. An integral part of the emergency shutdown system is the inert gas purging system. Upon an emergency shutdown, the BPG will be routed to the flares/TO for several minutes, until the flow rate of gas drops off to essentially zero. At this point, the inert gas system is activated by the emergency electrical power system, and forces an inert gas through the gasifier and its cyclones in sufficient volume that any combustible gases are reduced in concentration. The reduction in the concentration is sufficient to dilute the combustible gases below their lower explosive limit in an ambient air environment.

Routine shutdowns of the gasification island 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 to minimize initial airflow into the gasifier;
- 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 to determine when all the wood and carbon have been burned out of the gasifier;
- Maintain adequate upward flow during the transition from steam to air flow; and,
- Stop airflow into the gasifier once carbon burnout has occurred.

6.3. CTG Startups and Shutdowns

- *Cold Startup*: The applicant anticipates approximately six cold startups of the CTG combined cycle power block per year. At the request of the applicant for this project, Cold startup is defined as when the pressure in the high-pressure steam drum falls below 450 psig for at least one hour. A cold startup of the entire CTG/HRSG/STG system is defined as a startup after the system has been shut down for at least 48 hours.

  Cold startup of the SOLAR CTG/HRSG will happen sequentially over a 24 hour period with each CTG/HRSG unit brought on line at low load. Each SOLAR CTG/HRSG unit will initially be started with a fossil fuel at a low load. The load will gradually be increased to slowly increase the temperature of the STG and prevent metal fatigue.

- *Warm Startup*: A warm startup will last approximately 3 hours since the HRSG and STG do not require extensive warming. Otherwise, the procedures used during a warm startup are similar to a cold startup.

- *Shutdown*: Shutdown of the CTG/HRSG/STG system will take approximately three hours. The load, i.e., fuel flow, to each CTG is gradually reduced until it is shut off. Whether a warm or cold restart will occur subsequently depends upon the duration of the system shutdown as defined above.

7. AMBIENT AIR QUALITY

7.1. Introduction

The NWFREC is not subject to the PSD rules and ambient air modeling is not required. The applicant nevertheless performed a limited analysis on ambient impacts from the project. The analysis is summarized on pages 30-35 in the application at:
www.dep.state.fl.us/air/emission/bioenergy/northwest_renewable/2Application%20Report.pdf

The Department reviewed information from its own resources regarding emission trends and measured ambient air quality concentrations and has summarized this information in the following sections.

7.2. Emissions from Stationary Sources in Gulf and Nearby Counties

Tables 11 to 15 list the largest sources of criteria pollutants across Northwest Florida (nearest to the project site) per annual operating reports (AOR) filed with the Department in calendar year 2009. Past emissions from year 1995 have also been listed, in addition to the future contributions of the NWFREC. Facilities have been arranged from greatest to least 2009 emissions.

Table 11. Largest Sources of SO_2 Nearest to the Project.

Owner	Site Name	County	1995 TPY	2009 TPY
Gulf Power	Plant Lansing Smith	Bay	42,211	11,290
Smurfit-Stone Container	Panama City Mill	Bay	3,877	2,910
Stone Container Corp.	Port St Joe Facility (closed)	Gulf	1,490	0
NWFREC	**NWFREC (proposed)**	**Gulf**	**N/A**	**73 (future)**
Gulf Power	Scholz Plant	Jackson	3,725	59
St. Marks Powder	St. Marks Powder	Wakulla	151	29
Bay Co. BCC [1]	Bay Co Waste-to-Energy Facility	Bay	218	23
G-P Wood Products [1]	Hosford Facility	Liberty	0	15
WM of Leon Co. [1]	Springhill Regional Landfill	Jackson	N/A [2]	15
Arizona Chemical	Panama City Facility	Bay	39	14

1. BCC means Board of County Commissioners; WM means Waste Management; GP means Georgia-Pacific.
2. N/A means data not available or may have been constructed or started reporting such emissions after 1995.

Locations of these key facilities are shown in Figure 11.

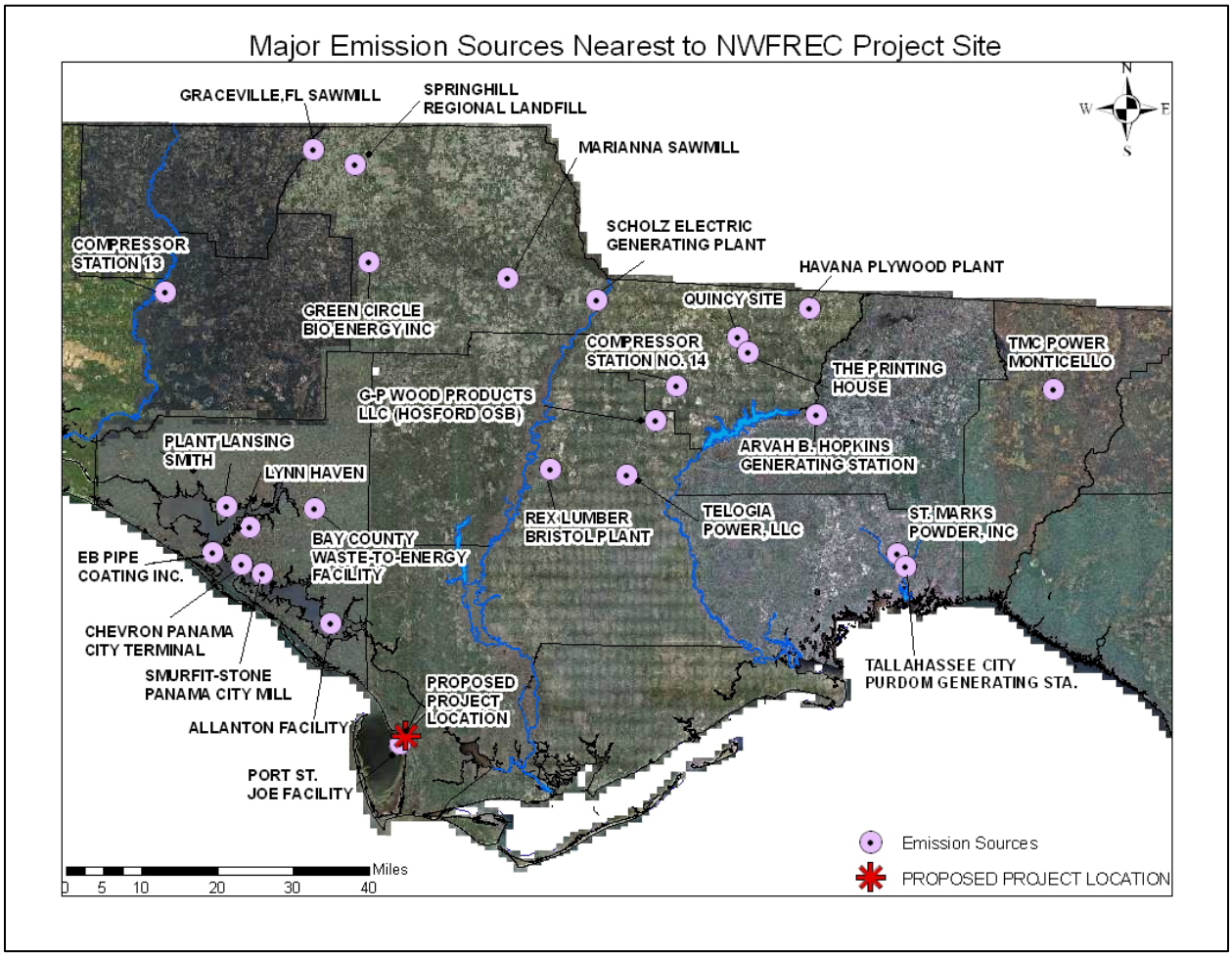


Figure 11. Largest Emission Sources Nearest to Project Site

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

Owner	Site Name	County	1995 TPY	2009 TPY
Gulf Power	Plant Lansing Smith	Bay	7,976	3,478
Smurfit-Stone Container	Panama City Mill	Bay	3,693	1,667
Stone Container Corp.	Port St Joe Facility (closed)	Gulf	2,358	0
FL Gas Transmission	Station 14	Gadsden	982	621
FL Gas Transmission	Station 13	Washington	924	595
City of Tallahassee	Hopkins Power Plant	Leon	3,613	238
G-P Wood Products	Hosford Facility	Liberty	N.A.	202
Bay Co BCC	Bay Co Waste-to-Energy Facility	Bay	124	181
NWFREC	**NWFREC (proposed)**	**Gulf**	**N/A**	**163 (future)**
City of Tallahassee	Purdom Power Plant	Wakulla	706	162
Arizona Chemical	Panama City Facility	Bay	257	98

Table 13. Largest Sources of PM Nearest to the Project.

Owner	Site Name	County	1995 TPY	TPY
Stone Container Corp.	Port St Joe Facility (closed)	Gulf	1,657	0
Smurfit-Stone Container	Panama City Mill	Bay	1,024	788
Gulf Power	Plant Lansing Smith	Bay	348	657
Green Energy BioEnergy	Jackson County Facility	Jackson	N/A	266
Coastal Forest Resources	Havana Plywood Plant	Gadsden	N/A	111
G-P Wood Products	Hosford Facility	Liberty	N/A	90
NWFREC	**NWFREC (proposed)**	**Gulf**	**N/A**	**78 (future)**
North Florida Lumber	Rex Lumber	Liberty	67	78
Gulf Power	Scholz Power Plant	Jackson	26	63

Table 14. Largest Sources of CO Nearest to the Project.

Owner	Site Name	County	1995 TPY	TPY
Smurfit-Stone Container	Panama City Mill	Bay	4,143	6,909
Smurfit Container Corp.	Port St Joe Facility (closed)	Gulf	2,337	0
Gulf Power	Plant Lansing Smith	Bay	277	499
TMC Power	TMC Power – Monticello	Jefferson	5	197
Bay Co. BCC	Bay Co. Waste-to-Energy Facility	Bay	274	177
NWFREC	**NWFREC (proposed)**	**Gulf**	**N/A**	**150 (future)**
North Florida Lumber	Rex Lumber – Bristol Plant	Liberty	197	130
Multitrade Biomass	Telogia Power	Liberty	1,264	101
City of Tallahassee	Purdom Power Plant	Wakulla	54	88
City of Tallahassee	Hopkins Power Plant	Leon	257	84
Spanish Trail Lumber Co.	Marianna Sawmill	Jackson	40	84
FL Gas Transmission	Station 14	Gadsden	167	78
Rex Lumber	Graceville Sawmill	Jackson	N/A	77
Coastal Forest Resources	Havana Plywood Plant	Gadsden	283	73

Table 15. Largest Sources of VOC Nearest to the Project.

Owner	Site Name	County	1995 TPY	TPY
Smurfit-Stone Container	Panama City Mill	Bay	1,063	899
Smurfit Container Corp.	Port St Joe Facility (closed)	Gulf	700	0
St. Marks Powder	St. Marks Powder	Wakulla	20	446
Arizona Chemical	Panama City Facility	Bay	166	216
Rex Lumber	Graceville Mill	Jackson	N/A	200
Spanish Trail Lumber Co.	Marianna Sawmill	Jackson	N/A	187
North Florida Lumber	Rex Lumber – Bristol Plant	Liberty	19	176
Green Circle BioEnergy	Jackson County Facility	Jackson	N/A	132
Trane	Lynn Haven Operation	Bay	N/A	88
NWFREC	**NWFREC (proposed)**	**Gulf**	**N/A**	**24**

Emissions of SO_2, NO_X, PM, CO and VOC within Gulf County were much less in 2009 compared with 1995, prior to the closure and dismantlement in 2002 of the Stone Container Corporation (SCC) Facility in Port St. Joe, which was located within a mile of the proposed NWFREC site. The decreases due to the closure of SCC ranged from 700 TPY of VOC to 2,358 TPY of SO_2.

By comparison, the projected emissions from the NWFREC range from 24 TPY of VOC to 163 TPY of NO_X. The sum of the emissions from the NWFREC will be approximately 3.2% compared with the previous reported emissions from SCC.

On a wider scale including the nearby counties, emissions of the same pollutants have been reduced by approximately 50,000 TPY, including nearly 32,000 TPY of SO_2 alone from Gulf Power, Plant Lansing Smith in Bay County. The expected emissions from the NWFREC compared with emissions from the existing individual facilities in the nearby counties range from 0.6% in the case of SO_2 (versus Gulf Power, Plant Lansing Smith) and 10% in the case of PM (versus Smurfit-Stone, Panama City).

Overall, emissions (particularly in the case of NO_X and SO_2) from the facilities nearest to the project site have declined significantly over the past 15 years. Furthermore, the closure of the SCC Port St. Joe Facility greatly reduced stationary source emissions in Gulf County. Finally, increases from the NWFREC are a small fraction of the emissions from the closed facility and an even smaller fraction of the emissions from the individual largest existing facilities in nearby counties.

There are regional efforts underway through the Federal Acid Rain Program and the Clean Air Interstate Rule (CAIR) to reduce emissions of NO_X and SO_2. Regional SO_2 emissions from existing power plants in the Southeast U.S. in 1995, 2007 and 2010 are listed in Table 16.

Table 16. SO_2 Emission from Power Plants in the Southeast in 1995, 2007 and 2010 (TPY).

State	1995	2007	2010	Δ Since 1995 (%)	Δ Since 2007 (%)
Alabama	532,485	447,189	204,197	328,288 (62%)	242,992 (54%)
Florida	**598,262**	**317,582**	**144,552**	**453,710 (76%)**	**173,030 (54%)**
Georgia	478,904	635,484	218,911	259,993 (54%)	416,573 (66%)
Kentucky	676,263	379,837	271,514	404,749 (60%)	108,323 (29%)
Mississippi	83,869	69,796	54,696	29,173 (35%)	15,100 (22%)
North Carolina	385,737	370,826	120,387	265,350 (69%)	250,439 (68%)
South Carolina	177,855	172,726	94,656	83,199 (47%)	78,070 (45%)
Tennessee	493,472	237,231	118,723	374,749 (76%)	118,508 (50%)
Total	**3,426,847**	**2,630,671**	**1,227,636**	**2,199,211 (64%)**	**1,403,035 (53%)**

SO_2 emissions from power plants in the Southeast U.S. were reduced by nearly 2,200,000 TPY and 64% referenced to emissions in 1995. Over 1,200,000 TPY of those reductions occurred during the past three years alone. The state and regional SO_2 reduction trends will continue as coal fueled power plants continue to install scrubbers to control SO_2 emissions and in anticipation of additional regulations to control HAP.

SO_2 emissions from power plants in Florida were reduced by 453,710 TPY and 76%. These reductions are the largest in the entire Southeast U.S. This is more than 6,000 times the future contribution of 73 TPY from the NWFREC and orders of magnitude greater than future SO_2 emissions from any realistic scenario of future biomass-fired facilities throughout the state.

Regional NO_X emissions from existing power plants in the Southeast U.S. in 1995, 2007 and 2010 are listed in Table 17. NO_X emissions from power plants in the Southeast U.S. were reduced by nearly 1,300,000 TPY and 74% referenced to emissions in 1995. Almost 450,000 TPY of those reductions occurred during the past three years alone.

Table 17. NO_X Emission from Power Plants in the Southeast in 1995, 2007 and 2010 (TPY).

State	1995	2007	2010	Δ Since 1995 (%)	Δ Since 2007 (%)
Alabama	202,776	122,374	66,049	136,727 (67%)	56,325 (46%)
Florida	**297,056**	**184,171**	**79,493**	**217,263 (73%)**	**104,678 (57%)**
Georgia	169,999	107,471	60,588	109,411 (64%)	46,883 (44%)
Kentucky	365,532	174,840	91,979	273,553 (75%)	82,861 (47%)
Mississippi	47,243	48,546	29,774	17,469 (37%)	18,772 (39%)
North Carolina	258,469	59,417	57,305	201,164 (78%)	2,112 (4%)
South Carolina	93,480	46,062	28,833	64,647 (69%)	17,229 (37%)
Tennessee	309,237	102,886	35,056	274,181 (89%)	67,830 (66%)
Total	**1,743,792**	**845,767**	**449,077**	**1,294,415 (74%)**	**396,690 (47%)**

The state and regional NO_X reduction trends will continue as coal-fueled power plants operators throughout the southeastern states continue to install SCR systems to control NO_X and in anticipation of additional regulations to control HAP.

NO_X emissions from power plants in Florida were reduced by more than 217,000 TPY (73%) with more than half of the reduction occurring in the past three years alone. This is about 1,300 times the future contribution of 163 TPY from the NWFREC and orders of magnitude greater than future NO_X emissions from any realistic scenario of future biomass-fired facilities throughout the state.

7.3. Ambient Air Quality Monitoring

The Department and its partners operate an extensive ambient air monitoring network. Most of the monitoring focuses on pollutants for which there exist National Ambient Air Quality Standards (NAAQS) such as nitrogen dioxide (NO_2), SO_2, ozone (O_3), PM_{10} and PM smaller than 2.5 micrometers ($PM_{2.5}$). The statewide monitoring network as configured in 2010 is shown below in Figure 12. The locations of monitors nearest to the NWFREC site in Gulf County are shown in Figure 13.

The monitors in St. Andrews State Park (Panama City) are the nearest to the proposed site and is the most representative from the standpoint of a meteorology and coastal morphology. These likely provide a conservative measure of ambient air quality given the presence of larger stationary sources nearer to Panama City than to Port St. Joe. Other monitors are less representative but are still conservative due to proximity to sources larger than those closest to Port St. Joe.

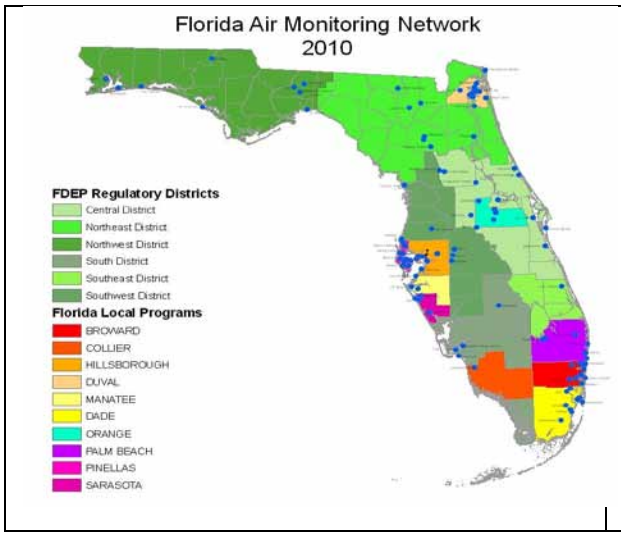


Figure 12. Statewide Monitoring Network.

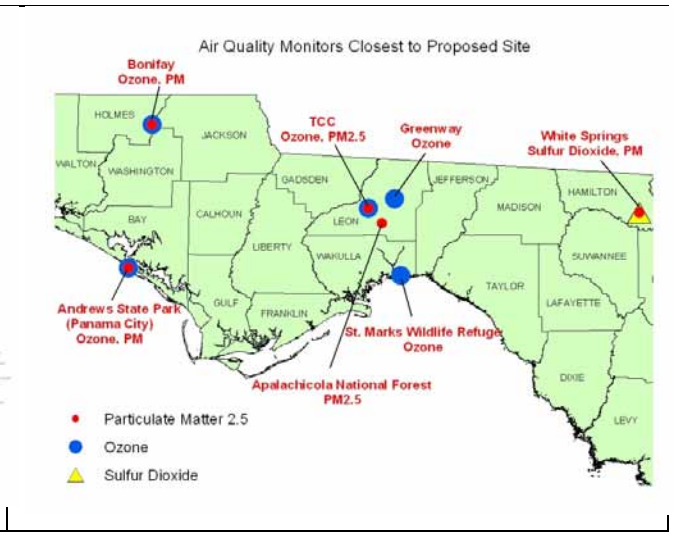


Figure 13. Stations nearest to the NWFREC Site.

Air quality measurements from these monitors are summarized in Table 18 and are compared with the NAAQS. Currently, all monitors in Florida are characterized as being in attainment with the NAAQS.

Table 18. Ambient Air Quality Summary Based on Monitors Nearest to Project Site (2007-2010).

Pollutant	Location (Site Number)	Averaging Period	Ambient Concentration			
			Compliance Period	Value	Standard	Units [a]
PM_{10}	Panama City (A0051004)	24-hour [b]	2007	83	150	$\mu g/m^3$
		Annual [c]	2008	22	50	$\mu g/m^3$
$PM_{2.5}$	Panama City (A0051004)	24-hour [d]	2007-2009	20	35	$\mu g/m^3$
		Annual [e]	2007-2009	10	15	$\mu g/m^3$
SO_2	White Springs (B0470015)	1-hour [i]	2008-2010	23	75	ppb
		3-hour [f]	2010	47	1300	$\mu g/m^3$
		24-hour [f]	2010	8	260	$\mu g/m^3$
		Annual [c]	2010	3	60	$\mu g/m^3$
NO_2	Pensacola (A0330004)	Annual [c]	2010	7	53	ppb
		1-hour [h]	2008-2010	37	100	ppb
CO	Jacksonville (L0310083)	1-hour [f]	2010	2	35	ppm
		8-hour [f]	2010	1	9	ppm
Ozone	Panama City (A0050006)	8-hour [g]	2008-2010	0.070	0.075	ppm

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 maximum daily 24-hour concentrations with exceptional events excluded (as approved by EPA).
e. Three year average of the arithmetic annual means with exceptional events excluded (per EPA).
f. Not to be exceeded more than once per year.
g. Three year average of the annual 4th highest daily 8-hour maximum.
h. Three-year average of the annual 98th percentile maximum daily 1-hour value (design value).
i. Three-year average of the annual 99th percentile maximum daily 1-hour value.

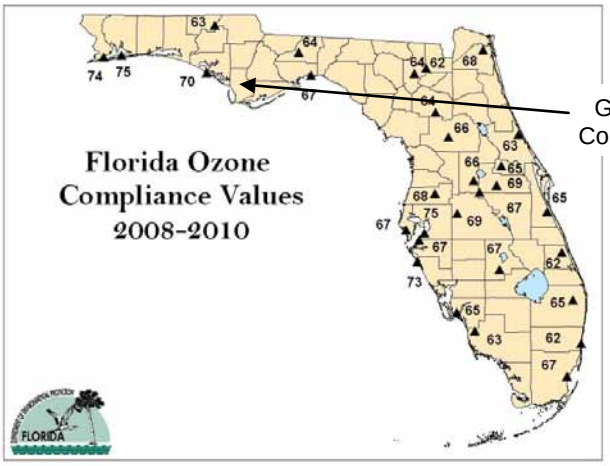
7.3.1. Existing Ambient Air Quality – $PM_{2.5}$ and Ozone

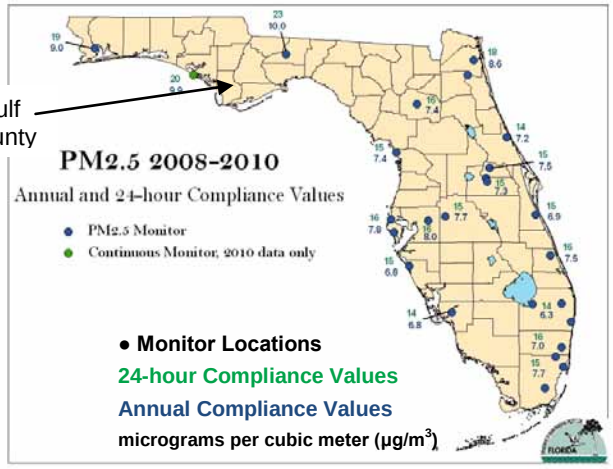
Ozone is a key indicator of the overall state of regional air quality. It is not emitted directly from combustion processes. Rather it is formed from VOC and NO_X emitted primarily from regional industrial and transportation sources. VOC is also emitted from fires and vegetation (e.g. isoprene). These two precursors participate in photochemical reactions that occur on an area wide basis and are highly dependent on meteorological factors.

Ozone limits and measurements are summarized on three year blocks, rolled annually. The reported ozone value was calculated by taking the maximum 8-hour readings recorded each day during the three years. The fourth highest of the recorded maxima were identified for each year and then the average of those three values was reported as the compliance value, and is compared to the standard of 75 parts per billion (ppb).

According to Table 18, the calculated ozone compliance value for Bay County is 0.070 ppm or 70 ppb and is shown in Figure 13 along with the highest compliance values measured in each county where at least one ozone station is located.

$PM_{2.5}$ (also known as PM_{fine}) is another key indicator of the overall state of regional air quality. Some $PM_{2.5}$ is directly emitted as a product of combustion from transportation and industrial sources as well as fires. Much of it consists of particulate nitrates and sulfates formed through chemical reactions between gaseous precursors such as SO_2 and NO_X from combustion sources and NH_3 naturally present in the air or added by other industrial sources.





Gulf County

Figure 14. Florida Ozone Compliance Values. **Figure 15. Florida $PM_{2.5}$ Compliance Values.**

$PM_{2.5}$ limits and measurements are summarized on three year blocks, rolled annually. The 24-hour compliance value was calculated by taking the average 24-hour readings recorded each day during the three years (2008-2010). The value for each year that exceeds 98% of all daily measurements within each given year was identified and then the average of those three numbers was reported as the 24-hour compliance value and compared with the standard of 35 $\mu g/m^3$.

For the Panama City site, which is closest to the NWFREC site, the reported 24-hour compliance value for $PM_{2.5}$ is 20 $\mu g/m^3$ and is shown in Figure 15 above along with the highest 24-hour compliance values measured in each county where at least one $PM_{2.5}$ station is located.

The simple average of all $PM_{2.5}$ measurements within each three years (2008-2010) was also calculated and then the mean of the three averages was reported as the annual compliance value and compared with the standard of 15 $\mu g/m^3$. For the Panama City site this compliance value was 9.9 $\mu g/m^3$.

The PM_{10} (coarse PM) monitor in Panama City was replaced with the $PM_{2.5}$ monitor. While it operated, the PM_{10} monitor was clearly measuring concentrations less than the respective annual and 24-hour standards.

The ambient air quality monitor results described above indicate that Bay County is in attainment with the applicable ozone and $PM_{2.5}$ NAAQS. Based on the foregoing discussion, the Department concludes that Gulf County is also in attainment with both standards as well.

Based on the large downward trend in regional and local $PM_{2.5}$ precursor emissions documented in Tables 11-17 above, the addition of $PM_{2.5}$ precursors (73 TPY of SO_2 and 163 TPY of NO_X) from NWFREC is minimal and will not affect the general and continuing downward trend. Similarly, $PM_{2.5}$ precursor emissions from the NWFREC should not have a measurable effect on local or regional $PM_{2.5}$ concentrations.

Based on the documented large downward trend in regional and local emissions of NO_X, the key ozone precursor, the contribution of 163 TPY of NO_X from NWFREC is minimal and will not affect the general and continuing downward trend in ozone precursor emissions. Similarly, these NO_X emissions will not have a measurable effect on local or regional ozone concentrations.

7.3.2. Existing Ambient Air Quality – NO_2, SO_2 and CO

The nearest NO_2, SO_2 and CO monitors to Port St. Joe are located in Pensacola, White Springs and Jacksonville, respectively. These are located near large sources of those pollutants, including a large NO_X/NO_2 source (Gulf Power Crist, Pensacola), several SO_2 sources (PCS Fertilizer, White Springs) and CO sources (Jacksonville traffic and industry). The measurements of NO_2, SO_2 and CO in Pensacola, White Springs and Jacksonville, respectively indicate those areas are in attainment with the NAAQS. These measurements would be conservative if applied to Gulf County.

Based on the foregoing discussion, the Department concludes that Gulf County is also in attainment with the NO_2, SO_2 and CO NAAQS as well.

Based on the large downtrend of regional and local emissions, the contribution of 73 TPY of SO_2 and 163 TPY of NO_X from NWFREC is extremely minimal and will not affect the general and continuing downward trend in $PM_{2.5}$ precursors. Similarly, it will not have a measurable effect on local or regional $PM_{2.5}$ concentrations

7.3.3. Exceptional Events Affecting $PM_{2.5}$ Concentrations

Certain $PM_{2.5}$ events are driven by wildfires in North Florida and South Georgia during periods of drought. La Niña, a naturally occurring, large-scale ocean-atmosphere climate phenomenon which occurs every 3 to 5 years, often spawns these droughts across the Southeastern United States and increases the potential for wildfires during these periods. Following is one description from The Christian Science Monitor (May 30, 2007).

"Sparked in mid-April (2007) by a combination of downed wires and lightning, the amalgam of fires now known as the Georgia Bay Complex – Bugaboo Scrub, Sweat Farm, Big Turnaround, and Kneeknocker – has already burned more than a half-million acres, exceeding the enormous fires that burst through the region in 1953 and 1954. The latest fires were declared a federal disaster April 17, entitling the state to federal aid. In an average year, wildfires burn 8,000 acres in Georgia; the Sweat Farm fire alone burned 10,000 acres in one night last week."

The same complex fires caused the cancellation of the 3-day Florida Folk Festival in White Springs, held annually at the Stephen Foster Folk Culture Center State Park managed by the Department. Figure 16 is a ground level photograph of the Georgia side of the fire. Figure 17 is a satellite Moderate Resolution Imaging Spectroradiometer (MODIS) image taken on May 11, 2007 after the fire(s) had raged for a month.

Figure 16. Georgia Bay/Okefenokee Complex Fire.

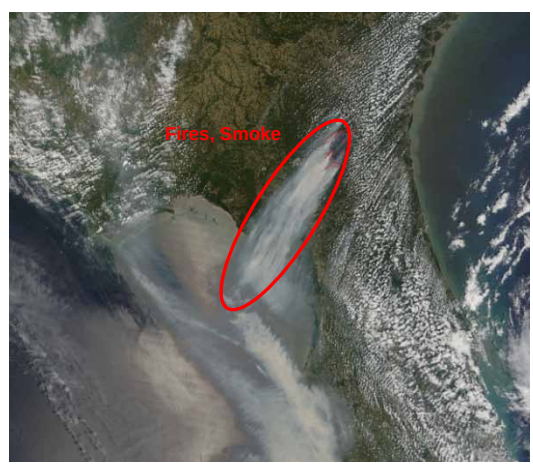


Figure 17. May 11, 2007 Satellite Image.

EPA approved removal of some of the data associated with this exceptional event. The data represented the highest measurements encountered during all of 2007. The event is important because it actually produced a great deal of $PM_{2.5}$ measured and felt by residents throughout North Florida.

Most recently, the Northern Hemisphere transitioned into La Niña during the summer of 2010 and has contributed to a widespread drought across the state, with 28% of Florida within moderate drought and 38% of the state suffering severe drought. Over 20% of the state was in extreme drought as of April 2011. Figure 18 is a graphical representation of the La Niña phenomenon and the manner by which is gives rise to the drought conditions.

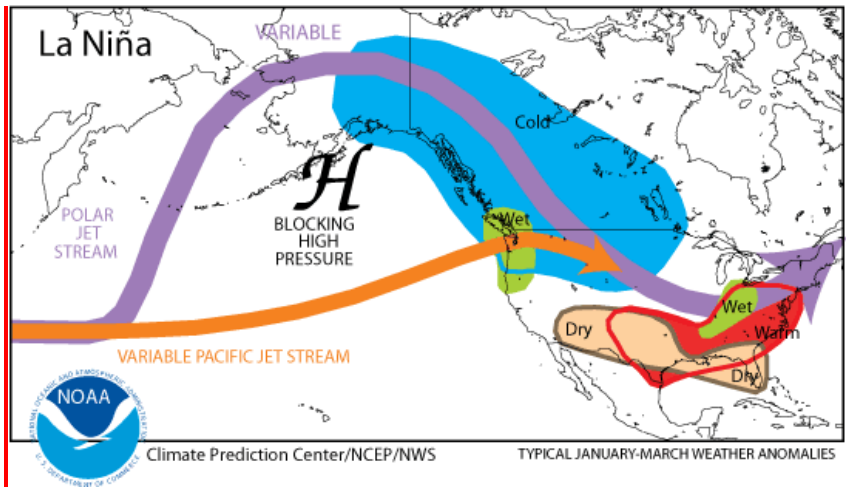
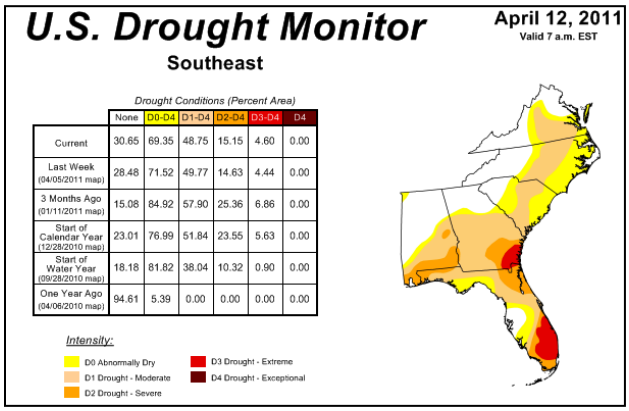


Figure 18. Typical Winter Weather Patterns during a La Niña Episode.

According to the National Climatic Data Center, a large complex of fires burned across Southeast Georgia during the last week of March 2011, torching a total of 41,850 acres. While the fires occurred in a relatively remote area, the effects on local air quality were certainly felt. $PM_{2.5}$ concentrations on March 25th at the White Springs air quality monitor reached 51.3 $\mu g/m^3$. This measurement is well above the 24-hour standard, and is a direct result of northerly winds carrying smoke to Florida from the aforementioned Georgia fires.

Figure 19 is a graphical representation of the prevalence and extent of drought in the Southeast U.S. on April 12, 2011. The Georgia fires and smoke paths into North Florida are shown in Figure 20.



	None	D0-D4	D1-D4	D2-D4	D3-D4	D4
Current	30.65	69.35	48.75	15.15	4.60	0.00
Last Week (04/05/2011 map)	28.48	71.52	49.77	14.63	4.44	0.00
3 Months Ago (01/11/2011 map)	15.08	84.92	57.90	25.36	6.86	0.00
Start of Calendar Year (12/28/2010 map)	23.01	76.99	51.84	23.55	5.63	0.00
Start of Water Year (09/28/2010 map)	18.18	81.82	38.04	10.32	0.90	0.00
One Year Ago (04/06/2010 map)	94.61	5.39	0.00	0.00	0.00	0.00

Figure 19. U.S. Drought Monitor as of 4/12/2011. Figure 20. March 25, 2011 Satellite Image.

The Department has evaluated other $PM_{2.5}$ episodes, such as in 2005, and found they occur in conjunction with certain meteorological conditions in conjunction with very high SO_2 emissions and sulfate deposition throughout the entire Southeast.

Put into context, large regional NO_X and SO_2 emission sources in the Southeastern U.S. as well as fires brought about by drought events are much more important to local ozone and $PM_{2.5}$ levels than would be the minimal SO_2 and NO_X emissions from the proposed NWFREC. The massive reductions in NO_X and SO_2 from regional power plants in the past two years and expected similar reductions in the coming years are having and will continue to have ameliorative effects on regional ozone and $PM_{2.5}$ levels. Finally the recent availability of improved transportation fuels (e.g. ULSD Fuel Oil) will also improve air quality (including $PM_{2.5}$) locally and regionally.

13 CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant, the Department has made a preliminary determination that the proposed project will comply with all applicable state air pollution regulations as conditioned by the draft permit. The Department contacts are:

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Attachment 1 – Applicant's Proposed Mass Emission Limits and Associated Permit Limits

The applicant's proposed pollutant emission rates in pounds per hour (lb/hr) and tons per year (TPY) are given in the table below. The TPY and lb/hr values given in the table are round to nearest tenth of a ton or pound, respectively. The emergency generator (EU 007) and emergency fire pump engine (EU 008) are not shown in the table because all pollutant emissions are very small (1.0 TPY or less).

Table A-1. Emissions from individual Emission Units (EU) in lb/hr and (TPY).

CTG/HRSG (EU 009, 010 and 011)						
CTG Type	**CO**	**NO_X**	**SO_2**	**PM/PM_{10}**	**VOC**	**VE**
SOLAR T-130 [1]	5.5 (24.1)	9.00 (39.4)	0.9 (4.0)	4.7 (20.5)	1.1 (4.6)	20% [2]
GE MS6001B	16.5 (72.3)	27.0 (118.1)	2.7 (11.9)	14.1 (61.7)	3.2 (13.8)	
Permit Limits	The lb/hr rates are accepted as the draft permit limits for CTG					10%
Char Combustor (EU 003)						
	15.5 (67.7)	9.6 (42.0)	13.5 (59.1)	0.6 (2.5)	1.6 (7.0)	5% [2]
Permit Limits	These rates accepted as the permit limits for char combustor					20% [3]
Biomass Handling, Storage and Drying System (EU 001)						
	----	----	----	(12.5/7.0) [4]	----	----
Permit Limits	Opacity (VE) of 10% and 20% [5]					
BPG Cleanup System and Flare System (EU 004)						
	173.0 (8.7)	32.0 (1.6)	36.4 (1.8)	----	65.0 (3.3)	20% [2]
Permit Limits	Opacity (VE) of 0% [6]					
Compressor and STG Cooling Towers (EU 005)						
	----	----	----	(1.0/0.7) [7]		----
Permit Limits	Drift Rates [8]					
Auxiliary Boiler (EU 006)						
	5.0 (1.2)	5.9 (1.5)	0.4 (0.1)	0.0 (0.0)	0.3 (0.1)	20% [2]
Permit Limits	5% [9]					

1. Emission rates are for each SOLAR CTG (total of three).
2. Applicant requested excess emissions of 100% opacity (VE) for one hour per Rule 62-210.700 F.A.C.
3. VE of 5% opacity on 6 minute block average accepted for 20% opacity for one 6 minute block per hour.
4. PM and PM_{10} in TPY, respectively. Pound per hour emission rates not given.
5. No VE greater than 10% opacity, except for one 6 minute period no greater than 20% opacity from the outlets of the drop points, transfer points, vent screens and baghouses associated with this emission unit. Setting emission limits is not practical for fugitive emissions.
6. The flares shall be designed for and operated with no VE except for periods not to exceed a total of 5 minutes during any two consecutive hours. Setting limits for the other pollutants is not practical for the open flares proposed for the NWFREC.
7. PM and PM_{10} in TPY, respectively. Pound per hour emission rates are 0.23 and 0.17, respectively.
8. Permit limit drift rates are set at the applicant's requested values of 0.002% and 0.005% for the STG and compressor gases cooling towers, respectively.
9. No VE greater than 5% opacity, except for one 6 minute period no greater than 15% from auxiliary boiler stack.