Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer

THROUGH: Al Linero

FROM: David Read

DATE: April 22, 2011

SUBJECT: DEP File No. 0450012-002-AC
Northwest Florida Renewable Energy Center (NWFREC), LLC
Biomass Gasification Combined Cycle Unit

Attached for your review is the Draft Air Construction Permit package for the NWFREC that will be located in Gulf County at 521 Premier Drive in Port St. Joe, Florida.

This project is not subject to the rules for the Prevention of Significant Deterioration. We recommend your approval of the attached draft permit package.

Attachments

TLV/aal/dlr

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Mr. John Diesch, Authorized Representative
Northwest Florida Renewable Energy Center, LLC
1331 17th St., Suite 720
Denver, Colorado 80202

DEP File No. 0450012-002-AC
NWFREC
BGCC Unit
Gulf County, Florida

Facility Location: The proposed NWFREC will be located at 521 Premier Drive in Port St. Joe, Gulf County, Florida.

Project: The project is to construct the NWFREC, which will be a nominal 55 megawatts (MWnet) biomass gasification combined cycle unit and ancillary equipment. The feedstock for the facility will be woody biomass that consists primarily of wood chips, saw dust, land clearing debris, round wood residues and may include a vegetative fuel crop. A review pursuant to the rules for Prevention of Significant Deterioration (PSD) and a determination of best available control technology (BACT) pursuant to Rule 62-212.400, F.A.C. were not required.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210 and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Bureau of Air Regulation's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's telephone number is 850/717-9000.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m, Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address or phone number listed above. Key documents are also available on-line at:

www.dep.state.fl.us/air/emission/bioenergy/northwest_renewable.htm

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Permit (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at above address or phone number. Pursuant to Rule 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 7 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of 14 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of the 14-day period. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within 14 days of receipt of this Written Notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of the attached Public Notice or within 14 days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida

for Trina Vielhauer, Deputy Director
Division of Air Resource Management

4/27/2011
(Date)

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Written Notice of Intent to Issue Air Permit Package (including the Written Notice of Intent to Issue Air Permit, the Public Notice of Intent to Issue Air Permit, the Technical Evaluation and Preliminary Determination and the Draft Permit with Appendices) was sent by electronic mail, or link to these documents made available electronically on a publicly assessable server, with received receipt requested before close of business on 4/27/11 to the persons listed below.

Mr. John Diesch, NWFREC, LLC	jdiesch@rentk.com
Glenn Farris, Biomass Energy Holdings	gfarris@bioeh.com
Kenn Davis, NWFREC, LLC	kdavis@bioeh.com
Scott Osbourn, P.E., Golder Associates	sosbourn@golder.com
Heather Abrams, EPA Region 4	abrams.heather@epa.gov
Diane Brown	db4635@aol.com
Marilyn Blackwell	marilynblackwel@wmconnect.com
Margaret Sheehan, Qualified Representative	meg@ecolaw.biz
Wayne Childers	702 Monument Avenue, Port St. Joe, FL 32456
Sally Malone	135 Ponce de Leon, Port St. Joe, FL 32454
Marjery Stitt	551 County Rd. 20, Wewahitchka, FL 32465
Help Save the Apalachicola River Group	c/o 4812 CR 381, Wewahitchka, FL 32465
Victor Ramos	2682 Indian Pass Road, Port St. Joe, FL 32456
Janet Reinhart	1493 Indian Pass Road, Port St. Joe, FL 32456
Robert Reinhart	1493 Indian Pass Road, Port St. Joe, FL 32456
Joseph Romanelli	690 Indian Pass Road, Port St. Joe, FL 32456
Marie Steele	690 Indian Pass Road, Port St. Joe, FL 32456
Harry L. Paul	183 S. Seminole St., Port St. Joe, FL 32456-7852
Zebe Schmitt	8181 West Highway 98, Port St. Joe, FL 32456
Denise Williams	879 CC Land Road, Eastpoint, FL 32328
Effie Browning	440 Treasure Drive, Port St. Joe, FL 32456
Landy Luther	135 South Higgins, Port St. Joe, FL 32456
Nancy Luther	135 South Higgins, Port St. Joe, FL 32456
Mark Schultz	1415 Indian Pass Road, Port St. Joe, FL 32456
Mary Schultz	1415 Indian Pass Road, Port St. Joe, FL 32456
Gloria Austin	1580 Indian Pass Road, Port St. Joe, FL 32456
Jonathan Hooper	404 Plantation Drive, Port St Joe, FL 32456
Debbie Hooper	404 Plantation Drive, Port St Joe, FL 32456

Joseph Heslin	1530 Indian Pass Road, Port St Joe, FL 32456
Nicole Widdersham	310 Fortner Ave, Mexico Beach, FL 32410
Bobby Cherry	427 7th Street, Mexico Beach, FL 32410
Joy Towles Ezell	hopeforcleanwater@yahoo.com
Bob Fulford	bobfulford@nettally.com
Dr. Ronald Saff	ronsaff@aol.com
William Bunn	w_bunn1@bellsouth.net
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Dr. Andres Rodriguez	1204 Miccosukee Road, Tallahassee, FL 32308
Rick Bradburn, DEP Northwest District Office	rick.bradburn@dep.state.fl.us
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Jennifer Diaz, DEP	jennifer.diaz@dep.state.fl.us
Ronni Moore, DEP OGC	ronni.moore@dep.state.fl.us
Dan Tonsmeire, Apalachicola Riverkeeper	dan@Apalachicolariverkeeper.org
Vickie Gibson, DEP for Read File	victoria.gibson@dep.state.fl.us

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

(Clerk) 4/27/11 (Date)

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Mr. John Diesch, Authorized Representative	DEP File No. 0450012-002-AC
Northwest Florida Renewable Energy Center, LLC	NWFREC
1331 17th St., Suite 720	BGCC Unit
Denver, Colorado 80202	Gulf County, Florida

Facility Location: The proposed NWFREC will be located at 521 Premier Drive in Port St. Joe, Gulf County, Florida.

Project: The project is to construct the NWFREC, which will be a nominal 55 megawatts (MWnet) biomass gasification combined cycle unit and ancillary equipment. The feedstock for the facility will be woody biomass that consists primarily of wood chips, saw dust, land clearing debris, round wood residues and may include a vegetative fuel crop. A review pursuant to the rules for Prevention of Significant Deterioration (PSD) and a determination of best available control technology (BACT) pursuant to Rule 62-212.400, F.A.C. were not required.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210 and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Bureau of Air Regulation's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's telephone number is 850/717-9000.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m, Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address or phone number listed above. Key documents are also available on-line at:

www.dep.state.fl.us/air/emission/bioenergy/northwest_renewable.htm

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Permit (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact

Florida Department of Environmental Protection
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Herschel T. Vinyard Jr.
Secretary

Electronically Sent – Received Receipt Requested.

jdiesch@rentk.com
Mr. John Diesch, Authorized Representative
Northwest Florida Renewable Energy Center, LLC
1331 17th St., Suite 720
Denver, Colorado 80202

Re: DEP File No. 0450012-002-AC
Northwest Florida Renewable Energy Center (NWFREC)
Biomass Gasification and Combined Cycle Unit

Dear Mr. Diesch:

On February 1, 2011, we received an application for an air construction permit subject to the preconstruction review requirements of Rule 62-212.300, Florida Administrative Code (F.A.C.).

The purpose of the project is to construct a nominal 55 megawatt (MWnet) biomass gasification and combined cycle (BGCC) unit called the NWFREC to be located in Gulf County at 521 Premier Drive in Port St. Joe, Florida.

Enclosed are the following documents: Written Notice of Intent to Issue Air Permit; Public Notice of Intent to Issue Air Permit; Technical Evaluation and Preliminary Determination; and a Draft Permit with Appendices.

The Public Notice of Intent to Issue Air Permit is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project.

If you have any questions, please contact Alvaro Linero at (850)717-9076 or David Read at (850)717-9075.

Sincerely,

for Trina Vielhauer, Deputy Director
Division of Air Resource Management

4/27/2011
(Date)

TLV/aal/dlr

Enclosures

PROFESSIONAL ENGINEER CERTIFICATION STATEMENT

Permittee:
Northwest Florida Renewable Energy Center, LLC
1331 17th St., Suite 720
Denver, Colorado 80202

DEP File No. 0450012-002-AC
Northwest Florida Renewable Energy Center
Biomass Gasification Combined Cycle Unit
Gulf County, Florida

Project: To construct the Northwest Florida Renewable Energy Center consisting of a nominal 55 megawatts (MWnet) biomass gasification combined cycle unit and ancillary equipment. The project will be located in Port St. Joe, Gulf County, Florida. Details of the project are provided in the application available at:

www.dep.state.fl.us/air/emission/bioenergy/northwest_renewable.htm

The project did not trigger the rules for the Prevention of Significant Deterioration (PSD) of air quality and a determination of Best Available Control Technology (BACT) was not required.

The control equipment, testing requirements and emission limitations are given in the technical evaluation and preliminary determination and the draft permit to which this certification applies. These documents are available at the web link given above.

***I HEREBY CERTIFY** that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including, but not limited to, the electrical, mechanical, structural, hydrological, geological, and meteorological features).*

4/27/2011

Alvaro A. Linero, P.E.
Registration Number: 26032

(Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Division of Air Resource Management, Bureau of Air Regulation
DEP File No. 0450012-002-AC
Northwest Florida Renewable Energy Center
Gulf County

Applicant: The applicant for this project is Northwest Florida Renewable Energy Center, LLC. The applicant's authorized representative and mailing address is: Mr. John Diesch, Authorized Representative, Northwest Florida Renewable Energy Center, LLC, 1331 17th Street, Suite 720, Denver, Colorado 80202.

Facility Location: The proposed Northwest Florida Renewable Energy Center (NWFREC) will be located at 521 Premier Drive in Port St. Joe, Gulf County, Florida.

Project: The project is to construct the NWFREC, which will be a nominal 55 megawatts (MWnet) biomass gasification combined cycle unit and ancillary equipment. The feedstock for the facility will be woody biomass that consists primarily of wood chips, saw dust, land clearing debris, round wood residues, yard waste and may include a vegetative fuel crop.

The biomass will be dried and fed into a gasifier vessel containing a heated bed of circulating sand where the biomass will be gasified and converted to biomass product gas (BPG). The BPG will then be cleaned, compressed and used as fuel in three SOLAR Model Number T-130 combustion turbine-electrical generators (CTG) or one General Electric (GE) Model MS6001B CTG. Heat from the CTG exhaust gas will be recovered in one or three heat recovery steam generators (HRSG) depending upon the CTG selected. Char from the gasifier and tars from the BPG cleanup will be combusted in the char combustor. The heat will be recovered to produce steam. The resulting steam from the HRSG will drive a single steam turbine-electrical generator (STG). Additional equipment includes an emergency generator, firewater pump, auxiliary boiler and flare/thermal oxidizer system.

Potential emissions will be less than the major stationary source thresholds. Therefore, a review for the Prevention of Significant Deterioration (PSD) including ambient air quality impact analyses and a Best Available Control Technology (BACT) determination were not required. The project is not a major source of hazardous air pollutants (HAP) and a determination of Maximum Achievable Control Technology (MACT) is not required. The project is an area source of HAP and the char combustor is subject to 40 Code of Federal Regulations (CFR) Part 63, Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants (NESHAP) for Area Sources: Industrial, Commercial, and Institutional Boilers.

The application, additional information and the Department's technical evaluation and preliminary determination (TEPD) are available at the following website:

www.dep.state.fl.us/air/emission/bioenergy/northwest_renewable.htm

The project will result in emissions increases (rounded up to nearest ton) of: 160 tons per year (TPY) of carbon monoxide (CO); 166 TPY of nitrogen oxides (NO_X); 78 TPY of particulate matter (PM); 72 TPY of PM with a mean diameter of 10 micrometers (μm) or less (PM_{10}); 75 TPY of sulfur dioxide (SO_2); 28 TPY of volatile organic compounds (VOC); 8 TPY of sulfuric acid mist (H_2SO_4); 9 TPY of ammonia (NH_3) slip and 11 TPY of HAP.

(Public Notice to be Published in the Newspaper)

Emissions from the char combustor will be controlled by NH_3-based selective non-catalytic reduction, a fabric filter and good combustion practices (GCP). Emissions from the CTG will be controlled by the BPG cleanup system, GCP, water or steam injection, an oxidation catalyst and NH_3-based selective catalytic reduction. Emissions from ancillary equipment (emergency generator, firewater pump, auxiliary boiler and flare/thermal oxidizer) will be controlled by GCP and/or the use of inherently clean and low sulfur fuels. The BPG cleanup system includes particulate removal, tar removal, and caustic scrubbing to remove other impurities. Reasonable precautions through a best management practices (BMP) plan will be employed to minimize fugitive dust emissions from biomass handling, storage and processing.

The project will include continuous emissions monitoring systems (CEMS) for NO_X and CO on the char combustor and CTG/HRSG stacks and a continuous opacity monitoring system (COMS) on the char combustor stack.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210 and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Permitting Authority responsible for making a permit determination for this project is the Bureau of Air Regulation in the Department of Environmental Protection's Division of Air Resource Management. The Bureau of Air Regulation's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Bureau of Air Regulation's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's telephone number is 850/717-9000.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at the physical address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application and information submitted by the applicant (exclusive of confidential records under Section 403.111, F.S.). Interested persons may contact the Permitting Authority's project engineer for additional information at the address and phone number listed above. In addition, electronic copies of these documents are available at the website provided above.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air construction permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of 14 days from the date of publication of this Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of the 14-day period. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241). Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within 14 days of publication of this Public Notice or receipt of a written notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address and telephone number of the petitioner; the name address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial rights will be affected by the agency determination; (c) A statement of when and how the petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available for this proceeding.

(Public Notice to be Published in the Newspaper)

DRAFT PERMIT

PERMITTEE

Northwest Florida Renewable Energy Center, LLC
1331 17th St., Suite 720
Denver, Colorado 80202

Air Permit No. 0450012-002-AC
Expires: December 31, 2015
Northwest Florida Renewable Energy Center (NWFREC)
Biomass Fed Gasification Combined Cycle Unit
Facility ID No. 0450012
Gulf County

Authorized Representative:
John Diesch, Authorized Representative

PROJECT AND LOCATION

This is the final air construction permit authorizing the construction of a nominal 55 megawatts (MWnet) biomass fed gasification and combined cycle (BGCC) power plant called the NWFREC. The new NWFREC facility is categorized under Standard Industrial Classification (SIC) No. 4911 for electrical services. The proposed project location is 521 Premier Drive in Port St. Joe, Gulf County, Florida. The UTM coordinates for this site are Zone 16; 664.16 kilometers (km) East and 3,301.96 km North.

This final permit is organized into the following sections: Section 1 (General Information); Section 2 (Administrative Requirements); Section 3 (Emissions Unit Specific Conditions); and Section 4 (Appendices). Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations which are defined in Appendix CF of Section 4 of this permit.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C.

Upon issuance of this final permit, any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida

(DRAFT)

Mike P. Halpin, P.E., Director — (Date)
Division of Air Resource Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final Air Permit package (including the Final Determination and Final Permit with Appendices) was sent by electronic mail, or a link to these documents made available electronically on a publicly accessible server, with received receipt requested before the close of business on ______________________________ to the persons listed below.

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Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

(Clerk) (Date)

FACILITY AND PROJECT DESCRIPTION

The proposed facility is a nominal 55 MW BGCC power plant called the NWFREC. The fuel source for the facility will be exclusively untreated woody biomass that consists primarily of wood chips but may also include agricultural crops and byproducts and logging and lumber mill residues as well as yard waste. Municipal solid waste (MSW) other than yard waste as defined in § 60.51b is expressly prohibited as a fuel source for the NWFREC.

The woody biomass will be dried and fed into a gasifier vessel containing a heated bed of circulating sand where the woody biomass will be gasified and converted to biomass product gas (BPG). The BPG will be cleaned, compressed and used as fuel in three 15.7 MW SOLAR Model Number T-130 combustion turbine-electrical generators (CTG) or one 45.6 MW General Electric (GE) Model MS6001B CTG. Heat from the CTG exhaust gas will be recovered in three (SOLAR CTG option) or one (GE CTG option) heat recovery steam generator(s) (HRSG). The resulting steam from the HRSG will drive a single 19.5 MW (GE CTG option) or 19.6 MW (SOLAR CTG option) steam turbine electrical generator (STG). After subtracting parasitic electrical loads at the facility of 11.3 MW, the net electrical output to be supplied to the power grid is 54.7 to 55.4 MW.

This project creates the following new emissions units. If the GE Model MS6001B CTG is selected by the permittee as EU-009 instead of the SOLAR Model Number T-130 CTG, the remaining two SOLAR CTG (EU-010 and -011) will not be installed at 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	15.7 MW SOLAR Model No. T-130 BPG-fueled CTG and HRSG <u>or</u> 45.6 MW GE Model MS6001B BPG-fueled CTG and HRSG
010	15.7 MW SOLAR Model No. T-130 BPG-fueled CTG and HRSG
011	15.7 MW SOLAR Model No. T-130 BPG-fueled CTG and HRSG

FACILITY REGULATORY CLASSIFICATION

- The facility is not a major source of hazardous air pollutants (HAP).
- The facility operates units subject to the acid rain provisions of the Clean Air Act (CAA).
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is not a major stationary source in accordance with Rule 62-212.400(PSD), F.A.C.
- The facility is subject to the provisions of the Clean Air Interstate Rule (CAIR), including applicable portions of Chapters 62-204, 62-210 and 62-296, F.A.C.

- The facility is subject to Chapter 62-204.800, F.A.C for New Source Performance Standards (NSPS) under Section 111 of the CAA and National Emissions Standards for Hazardous Air Pollutants (NESHAP) under Section 112 of the CAA.

1. Permitting Authority: The permitting authority for this project is the Bureau of Air Regulation, Division of Air Resource Management, Florida Department of Environmental Protection (Department). The Bureau of Air Regulation's mailing address is 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. All documents related to applications for permits to operate an emissions unit shall be submitted to the Title V Section of the same office.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's Northwest District Office at 160 Governmental Center, Suite 308, Pensacola, Florida 32502-5794. The telephone number of the district office is 850/595-8300. Copies of these documents shall also be submitted to the Northwest District's Branch Office at 3800 Commonwealth Blvd., Tallahassee, Florida 32301. The telephone number of the branch office is 850/245-2984.

3. Appendices: The following Appendices are attached as part of this permit and must be complied with by the permittee:
   a. Appendix A: Identification of General Provisions - NSPS 40 CFR 60, Subpart A and NSHAP 40 CFR 63, Subpart A;
   b. Appendix ASTM: ASTM Standard D6751-09 for Biodiesel;
   c. Appendix BMP: Best Management Practices Plan;
   d. Appendix CC: Common Conditions;
   e. Appendix CEMS: Continuous Emissions Monitoring System (CEMS) Requirements;
   f. Appendix CF: Citation Formats and Glossary of Common Terms;
   g. Appendix CTR: Common Testing Requirements;
   h. Appendix Db: NSPS, 40 CFR 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units;
   i. Appendix Dc: NSPS, 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units;
   j. Appendix GC: General Conditions;
   k. Appendix IIII: NSPS, Subpart IIII - Stationary Compression Ignition Internal Combustion Engines;
   l. Appendix JJJJJ: NESHAP 40 CFR 63, Subpart JJJJJ - National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers;
   m. Appendix KKKK: NSPS - Standards of Performance for Stationary Combustion Turbines; and,
   n. Appendix ZZZZ: NESHAP, Subpart ZZZZ - Stationary Reciprocating Internal Combustion Engines (RICE).

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.

5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. No new emissions unit shall be constructed and no existing emissions unit shall be

modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Source Obligation:

(a) Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit.

(b) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

(c) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

[Rule 62-212.400(12), F.A.C.]

8. Application for Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V air operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V air operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the appropriate Permitting Authority with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220 and Chapter 62-213, F.A.C.]

9. Objectionable Odors Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor. [Rule 62-296.320(2), F.A.C.]

{Permitting Note: An objectionable odor is defined in Rule 62-210.200(Definitions), F.A.C., as any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance.}

10. Open Burning Prohibited: No person shall ignite, cause to be ignited, or permit to be ignited, any material which will result in any prohibited open burning as regulated by chapter 62-256, F.A.C.; nor shall any person suffer, allow, conduct or maintain any prohibited open burning. [Rule 62-256.300, F.A.C.]

11. Unconfined Emissions of Particulate Matter: No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions. Any permit issued to a facility with emissions of unconfined particulate matter

shall specify the reasonable precautions to be taken by that facility to control the emissions of unconfined particulate matter. Appendix BMP of this permit provides a Best Management Plan (BMP) of reasonable precautions specific to the NWFREC facility to control fugitive PM emissions. Reasonable precautions include the following: a) Paving and maintenance of roads, parking areas and yards; b) Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing; c) Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities; d) Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent re-entrainment, and from buildings or work areas to prevent particulate from becoming airborne; e) Landscaping or planting of vegetation; f) Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter; g) Confining abrasive blasting where possible; and, h) Enclosure or covering of conveyor systems. In determining what constitutes reasonable precautions for a particular facility, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice. [Rule 62-296.320(4)(c), F.A.C.]

12. <u>Excess Emissions</u>: Except as required by specific conditions of this permit dealing with excess emissions with regard to individual emission units, the following conditions apply to excess emissions at NWFREC.
    a. <u>Allowed</u>: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing best operational practices to minimize emissions are adhered to and 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.
    b. <u>Malfunction</u>: 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.
    c. <u>Department Discretion</u>: 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.
    d. <u>Department Notification</u>: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700, F.A.C.]
13. <u>Facility-wide Emissions Report</u>: The owner or operator shall submit an Annual Operating Report (AOR) for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) to the Department annually pursuant to Rule 62-210.370(3), F.A.C. Using the computation methods described in Rule 62-210.370(2), F.A.C., the required AOR shall also include a demonstration that facility emissions of NO_X, CO, SO_2, VOC and PM/PM_{10} are each less than 250 tons per year (TPY). [Rule 62-210.370, F.A.C.]

A. Biomass Handling, Storage and Drying System (EU-001)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
001	Biomass handling, storage and drying system: This EU consists of two principal components each of which is briefly described below. The term biomass used throughout the subsection includes yard waste as defined in § 60.51b of NSPS 40 CFR 60, subpart Eb. • *Biomass Stackout*: Biomass fuels that are allowed at the NWFREC are described in **Specific Condition 6** of this subsection and in the best management practices (BMP) given in Appendix BMP. The BMP includes the woody biomass and fuel crop feedstock properties along with a plan for quality control. Deliveries of biomass fuel will be made via truck to the site. The trucks will be unloaded via a truck receiving system equipped with two 75 foot platforms that dump into two 5,000 cubic feet (ft^3) receiving hoppers. The hoppers will have a very slow moving chain drag to minimize dust. 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 or smaller material. The hog and ancillary conveyors will be supported in a common tower with applicable chute work and the dust generated controlled by a baghouse. Material will discharge from the hog onto a covered collection conveyor and then transition to the circular stacker. The circular stacker will form a kidney shaped pile approximately 2 million ft^3 in capacity at an average height of 40 feet. • *Biomass Reclaim*: Biomass will be reclaimed using a stacker reclaimer from the storage pile via a drag chain by three covered conveyors. Prior to entering the powerhouse the fuel will be conveyed via the last conveyer, which is controlled by a baghouse, to a dryer where the moisture is reduced from as high as 45 percent (%) to approximately 23%. Covered belt conveyors will then 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 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. All transfer systems from conveyor to conveyor employ totally enclosed head boxes, chutes, and skirt board systems to contain the fuel and any dust that may be produced at the transfer points. The day bin has a bin vent on top of it to filter the air displaced by transfer of wood into the bin. All conveyors will be covered to reduce particulate emissions. A baghouse will control emissions from the dyer.

EQUIPMENT

1. Equipment: The permittee is authorized to construct a biomass handling, storage and drying system consisting of the following major pieces of equipment.
   a. Truck Unloading System: The truck unloading system dumps into two receiving hoppers and shall be designed to minimize the generation of fugitive dust.
   b. Biomass Belt Conveyor Systems: All belt conveyor systems shall be enclosed and have totally enclosed head boxes, chutes and skirtboard systems to contain the fuel as well as prevent dust generation at the transfer points.
   c. Biomass Storage Pile: The biomass storage pile shall be managed in accordance with Appendix BMP.

d. Biomass Dryer: The biomass dryer shall use thermal heat transfer (no additional combustion) to dry biomass, if needed, prior to gasification.

e. Storage/Feeder Bin: The storage/feeder bin shall be enclosed and include a spreader conveyor, a bin vent filter and a bottom screw feeder for unloading.

f. Bucket Elevator: The bucket elevator shall be enclosed.

g. Baghouses: Based on the preliminary design, the permittee shall install the following baghouses. Each baghouse shall be designed and maintained to achieve an outlet dust loading rate of 0.01 grains per dry standard cubic feet (gr/dscf) in its exhaust. Based on the final engineering design needs, additional baghouses may be installed as necessary to control fugitive dust from material handling and storage. The Compliance Authority shall be notified 180 days before NWFREC becomes operational of any final engineering design changes. Should the preliminary design change, the permittee shall provide final design details for all baghouses in the application for a Title V air operation permit along with a concurrent modification of this air construction permit.

   1) *Hog Mill Baghouse* shall control dust from the screen to the hog mill and the hog mill will exhaust to the atmosphere at ambient temperature.

   2) *Reclaim Baghouse #1* shall control dust from Reclaim Conveyor 2 to Supply Conveyor 3 and exhausted to the atmosphere at ambient temperature.

   3) *Reclaim Baghouse #2* shall control dust from the thermal heat biomass dryer at a design volumetric flow rate of 110,000 standard cubic feet per minute (scfm) exhausted to the atmosphere at approximately 175 degrees Fahrenheit (°F).

h. Bin Vent Filter: A bin vent filter shall control dust from the storage/feeder bin. The filter shall be designed and maintained to control at least 99.8% of the inlet dust loading for a designed feed rate of 900 tons per day (TPD) at approximately 23% moisture.

{Permitting Note: Enclosed conveyors means that the conveyance belt for the biomass is totally enclosed from above thus preventing wind from causing fugitive dust emissions from the belt. However, the bottom of the conveyance belt shall be accessible for maintenance and repairs.}

[Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

3. Best Management Practice (BMP) Plan: A BMP plan shall be utilized to minimize fugitive PM emissions from receiving, handling, storage and processing of woody biomass. Best management practices shall be utilized to reduce the potential for spontaneous combustion of stored woody biomass and odors. A preliminary BMP plan is contained in Appendix BMP of this permit. This plan also includes quality control and assurance (Q&A) procedures to ensure woody biomass delivered by vendors and suppliers to the NWFREC meet the requirements given in **Specific Condition 6** of this subsection. No later than 180 days before the NWFREC becomes operational, a final BMP plan shall be filed with the Compliance Authority to reflect the final engineering designs of the biomass receiving, handling, storage and processing systems. The final BMP plan will also be incorporated into the Title V operating permit. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

4. Approximate Capacities: Each truck dumper will unload approximately 150 tons per hour (TPH) of biomass with an estimated moisture content of 45%. The covered storage area will hold approximately 12 to 14 days of biomass feedstock (approximately 20,000 tons on a wet basis). The dryer will dry approximately 1,285 TPD of wet biomass (assumes moisture content of 30%) and the feeder will transfer approximately 900 TPD of dry biomass feedstock to the gasifier (assumes moisture content of 23%). [Application No. 0450012-002-AC and Rule 62-210.200(PTE), F.A.C.]

5. Hours of Operation: The hours of operation of this emission unit are not limited (8,760 hours per year). [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

6. Woody Biomass Fuels: With the exception of yard waste as defined in § 60.51b (NSPS Subpart Eb - Standards of Performance for Large Municipal Waste Combustors), Municipal Solid Waste (MSW) is prohibited from use at this facility. The fuel shall consist of untreated woody biomass as described in this permit condition and in Appendix-BMP of this permit. Inspection and testing procedures describe in Appendix-BMP shall be followed to insure that appropriate woody biomass is used as fuel. A maximum of 30 TPD of yard waste as defined in § 60.51b can be used as a biomass fuel for the gasifier (EU 002) at the NWFREC.

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. NWFREC has identified the following possible, available feedstock types for their facility, including:

Fuel Type	Fuel Group Description
Pine Trees (slash, sand, loblolly)	Wood chips from slash, sand and loblolly pine trees
Saw Dust	Saw dust and other waste from cutting/milling whole green trees
Hogged Fuel	Land clearing debris that has either been processed, run through 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 materials from post or pole manufacturers.
Fuel (vegetative) Crop	Examples include: Arundo donax and 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.

[Application No. 0450012-002-AC; 62-4.070(3) F.A.C.; NSPS 40 CFR 60, Subpart Eb]

7. Paved Roadways and Gravel Areas: Fugitive dust emissions from the plant's paved roadways and gravel areas shall be controlled in accordance with **Specific Condition 11 of Section 2** of this permit. [Rules 62-4.070 and 62-296.320, F.A.C.]

EMISSIONS STANDARDS

8. Opacity: As determined by EPA Method 9, there shall be no visible emissions (VE) greater than 10% opacity, except for one 6 minute period no greater than 20% from the outlets of the drop points, transfer points, vent screens and baghouses associated with this emission unit. [Rules 62-4.070(3), 62-297.310(7)(c), and 62-212.400(5)(c), F.A.C.]

TESTING AND MONITORING REQUIREMENTS

9. Initial VE Compliance Tests: The outlets of the drop points, transfer points, silo vent screens associated with the fuel bins and dust collectors of this emissions unit shall be tested to demonstrate initial compliance with the emissions standards for opacity given in **Specific Condition 8** of this subsection. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the emission unit. [Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]

10. Annual VE Compliance Tests: During each federal fiscal year (October 1st to September 30th), the outlets of the drop points, transfer points, silo vent screens associated with the fuel bins and dust collectors of this emissions unit shall be tested to demonstrate compliance with the emissions standards for opacity given in

Specific Condition 8 of this subsection. [Rule 62-297.310(7)(a)4, F.A.C.]

11. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

12. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
EPA 9	Visual Determination of the Opacity of Emissions from Stationary Sources

The above method is described in Appendix A of 40 CFR 60 which is included as Appendix A of this permit and is adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department.
[Rules 62-204.800 and 62-297.100, F.A.C.; Appendix A of 40 CFR 60]

RECORDS AND REPORTS

13. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. For each test run, the report shall also indicate the operating rate. [Rule 62-297.310(8), F.A.C.]

B. Biomass Gasifier with NG Startup Burner (EU-002)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
002	Biomass gasifier with NG startup burner: The biomass feedstock will be converted in the gasifier by pyrolysis to BPG in a circulating fluidized bed (CFB) of hot sand that uses steam as the fluidization medium. During the process, the sand cools and the biomass feedstock breaks down to produce BPG including tar, char and ash. Cooled sand and char are captured in the gasifier cyclones and returned to the char combustor (EU 003) to support combustion and reheat the sand. The BPG from the gasifier cyclone is cooled in a heat exchanger and then cleaned as described in EU 004. The BPG is then combusted in the SOLAR T-130 CTG (EU 009, 010 and 011), GE MS6001B CTG (EU 009) or combusted in the Flare/TO System (EU 004). During some operational scenarios, such as emergency shutdown of the gasifier, the BPG may not be cleaned prior to flaring.

EQUIPMENT

1. Equipment: The permittee is authorized to construct a gasifier consisting of the following equipment: CFB gasifier vessel; NG-fueled startup burner; cyclones; ash handling system; and heat exchangers.
[Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

2. Cyclone Separators: One cyclone separator shall be designed, installed and maintained to remove char and sand from the raw BPG and recirculate it to the char combustor (EU 003) for combustion of the char and reheating of the sand. Another cyclone separator shall be designed, installed and maintained to remove the remaining coarse solid ash prior to BPG cleanup or flaring.
[Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

3. Gasifier Capacity: The maximum rate of biomass feed to the gasifier is 900 TPD at an approximately 23% moisture content. The gasifier fuel feed rate shall be measured and recorded by permanently installed equipment including but not limited to a belt scale to measure the actual mass flow, and daily gasifier feedstock sampling and analysis to determine the as-fed moisture content.

   The moisture content shall be obtained by using an accepted American Society of Testing and Materials (ASTM) method suitable for wood or woody biomass when used as a fuel. An accepted method suitable for wood or woody biomass as a fuel from the American Society of Mechanical Engineers (ASME) or the American Boiler Manufacturers Association (ABMA) can be used in lieu of an ASTM method. Records of daily feed rate and moisture content shall be available, and retained as accessible records.
[Application No. 0450012-002-AC; Rules 62-210.200(PTE) and 62-4.070, F.A.C.]

4. Gasifier Startup Burner Capacity: The design heat input rate of the NG fueled startup burner is 25 mmBtu per hour (mmBtu/hour). [Application No. 0450012-002-AC and Rule 62-210.200(PTE), F.A.C.]

5. Hours of Operation: The hours of operation of the gasifier are not limited (8,760 hours per year). The gasifier startup burner may be used only for the purpose of starting up the gasifier.
[Application No. 0450012-002-AC and Rule 62-210.200(PTE), F.A.C.]

NSPS APPLICABILITY

6. NSPS Subpart Dc and Subpart A Applicability: The gasifier startup burner is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial or Institutional Boilers and Subpart A, General Provisions. Specifically, this emission unit shall comply with 40 CFR 60.48c Reporting and Recordkeeping Requirements. The applicable conditions are given in Appendices A and Dc of this permit.
[Rule 62-204.800(7)(b); 40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units and 40 CFR 60 Subpart A, General Provisions]

C. Char Combustor Sand Heater with NG Startup Burner (EU-003)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
003	Char combustor sand heater with NG startup burner and sand handling equipment: Sand and char captured in the gasifier cyclones and tars (returned from downstream BPG cleaning system) are fed to the char combustor. Air is introduced at the bottom of the vessel and supports combustion of the char and tars in a CFB of sand. Heated sand is captured in the char combustor cyclones and returned to the gasifier to sustain pyrolysis. Exhaust gas from the char combustor passes through a sand cyclone and a hot ash cyclone, is cooled in a heat exchanger and then filtered in a baghouse.

EQUIPMENT

1. Equipment: The permittee is authorized to construct a char combustor and sand heater system consisting of the following equipment: Sand storage silo; CFB char combustor vessel; NG fueled startup burner; cyclones; heat exchangers; and a fabric filter baghouse.
   [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

2. Cyclone Separators: One cyclone separator shall be designed, installed and maintained to remove the heated sand from the char combustor exhaust and recycle it back to the gasifier (EU 002). Another cyclone separator shall be designed, installed and maintained to remove most of the hot gasification ash prior to further particulate removal in ash cyclone separator fabric filter baghouses described in **Specific Condition 3b** of this subsection. [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

3. Fabric Filter Baghouses: The permittee shall install and maintain the following baghouses. Exhaust from these baghouses discharges directly to the ambient air. Should the preliminary design of the baghouses change, the permittee shall provide final design details for all baghouses and controls in the application for a Title V air operation permit along with a concurrent modification of this air construction permit. The Compliance Authority shall be notified 180 days before NWFREC becomes operational of any final engineering design changes.

   a. *Sand Storage Silo*: Exhaust from the sand storage silo shall be controlled by a baghouse designed and maintained to limit PM/PM_{10} emissions to 0.01 gr/dscf or better in the baghouse exhaust.

   b. *Ash Cyclone Separator*: Exhaust from the second char combustor cyclone (ash) separator shall be further controlled by a separate baghouse designed and maintained to 0.005 gr/dscf or better in the baghouse exhaust.

   [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

4. Selective Non-Catalytic Reduction (SNCR) System: The permittee shall design, install, operate, and maintain an ammonia based SNCR system to reduce NO_X emissions in the char combustor flue gas exhaust and achieve the NO_X emissions standards specified in this subsection. The SNCR shall be on line and functioning properly whenever its operation is necessary to meet the NO_X emission standards given in this subsection as established by the CEMS output data.
   [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

5. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emissions of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

   *{Permitting Note: The char combustor SNCR system only needs to be operated when necessary to meet the NO_X emission standards given in **Specific Condition 15** of this subsection. Not operating the SNCR system so long as the NO_X emission standards are met does not constitute Circumvention of the SNCR system.}*

PERFORMANCE RESTRICTIONS

6. Char Combustor Capacity: The design heat input rate of the char combustor is 155 mmBtu/hour. [Application No. 0450012-002-ACand Rule 62-210.200(PTE), F.A.C.]

7. Char Combustor Startup Burner Capacity: The design heat input rate of the NG fueled startup combustor burner is 17 mmBtu/hour. [Application No. 0450012-002-AC and Rule 62-210.200(PTE), F.A.C.]

8. Hours of Operation: The hours of operation of this emissions unit are not limited (8,760 hours per year). The char combustor startup burner may be used only for the purpose of starting up the char combustor. [Application No. 0450012-002-AC and Rule 62-210.200(PTE), F.A.C.]

NSPS APPLICABILITY

9. NSPS Subpart Db and Subpart A Applicability: The char combustor is subject to all applicable requirements of 40 CFR 60, Subpart Db which applies to Industrial, Commercial or Institutional Steam Generating Units and Subpart A, General Provisions. The applicable conditions are given in Appendices A and Db of this permit.
[Rule 62-204.800(7)(b)3, F.A.C.; NSPS 40 CFR 60, Subpart Db and 40 CFR 60 Subpart A]

NESHAP APPLICABILITY

10. NESHAP Subpart JJJJJ and Subpart A Applicability: The char combustor is subject to all applicable requirements of 40 CFR 63, Subpart JJJJJ National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers and Subpart A, General Provisions. [Rule 62-204.800(7)(b)3, F.A.C.; NESHAP 40 CFR 63, Subpart JJJJJ and 40 CFR 63 Subpart A]

EMISSIONS STANDARDS

11. Char Combustor Baghouse – Opacity Standard: An initial char combustor stack test of 3 hours duration in accordance with §60.48b and utilizing EPA method 9 shall not exceed 5% opacity on a 6-minute block average except for one six minute period per hour of 20%. Subsequently, compliance shall be demonstrated by continuous opacity monitoring system (COMS). Based on the COMS, opacity shall not exceed 5% on a 6-minute block average except for one six minute period per hour of 20%. [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-297.310(7)(c), F.A.C.]

12. Sand Silo Baghouse – Opacity Standard: In accordance with EPA Method 9, VE from the sand silo baghouse shall not exceed 5% opacity based on a 6-minute average.
[Rules 62-4.070(3) and 62-297.310(7)(c), F.A.C.]

13. Particulate Matter (PM/PM_{10}) Emissions Limits:

    a. *NSPS Subpart Db and NESHAP Subpart JJJJJ Limits*: PM/PM_{10} emissions from the char combustor exhaust stack shall not exceed 0.030 pounds per mmBtu (lb/mmBtu) as demonstrated by initial and annual compliance tests. [NSPS 40 CFR 60, Subpart Db and NESHAP 40 CFR 63, Subpart JJJJJ]

    b. *Additional Limit*: PM/PM_{10} emissions from the char combustor exhaust stack shall not exceed 2.5 pounds per hour (lbs/hr) which is equivalent to 0.016 lb/mmBtu as demonstrated by initial and annual compliance tests.
    [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

14. Nitrogen Oxides (NO_X) Emissions Limits:

    a. *NSPS Subpart Db Limit*: NO_X emissions from the char combustor exhaust stack shall not exceed 0.30 lb/mmBtu on a 30 day rolling average basis as demonstrated by a continuous emission monitoring system (CEMS). [NSPS 40 CFR, Subpart Db]

b. *Additional Limit*: NO_X emissions from the char combustor exhaust stack shall not exceed 9.6 lb/hr (0.062 lb/mmBtu) on a 30 day rolling average basis as demonstrated by a CEMS.
[Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

15. Sulfur Dioxide (SO_2) Emissions Limits:

a. *NSPS Subpart Db Limit*: Units firing gaseous fuels, or a mixture of gaseous fuels with other fuels with a potential SO_2 emission rate of 0.32 lb/mmBtu heat input or less are exempt from the SO_2 emission limit of 0.20 lb/mmBtu given in § 60.42b(k)(2). According to the applicant, SO_2 emissions from the char combustor stack are 0.09 lb/mmBtu and consequently the char combustor satisfies the SO_2 emission limit exemption given in NSPS Subpart Db. [NSPS 40 CFR 60, Subpart Db]

b. *Additional Limit*: SO_2 emissions from the char combustor exhaust stack shall not exceed 13.5 lb/hr (0.087 lb/mmBtu) as demonstrated by initial and annual compliance tests. Meeting this SO_2 this emission limit shows compliance with the uncontrolled SO_2 emissions exemption of 0.32 lb/mmBtu given in § 60.42b(k)(2) of NSPS 40 CFR 60, Subpart Db. [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.; and NSPS 40 CFR 60, Subpart Db]

16. Carbon Monoxide (CO) Standard and Emissions Limit:

a. *NESHAP Subpart JJJJJJ Standard*: The permittee shall conduct a tune-up of the char combustor biennially as specified in §63.11223(b) to demonstrate continuous compliance with the work practice and management practice standards. [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.; NESHAP 40 CFR 63, Subpart JJJJJJ]

b. *Additional Limit*: Emissions of CO from the char combustor exhaust stack shall not exceed 15.5 lb/hr (0.10 lb/mmBtu) or approximately 94 ppmvd) on a 30 day rolling average basis as demonstrated by a CEMS.
[Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

17. Ammonia (NH_3) Slip: NH_3 emissions (slip) from the char combustor exhaust stack shall not exceed 10 ppmv @ 7% O_2 as demonstrated by initial and annual compliance tests. [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

TESTING AND MONITORING REQUIREMENTS

18. Continuous Monitoring Requirements: The permittee shall install, calibrate, maintain and operate a CO and NO_X CEMS, a COMS and a diluent monitor for carbon monoxide (CO_2) or oxygen (O_2) on the char combustor stack. The COMS, NO_X and CO CEMS shall be used to demonstrate continuous compliance with the opacity, NO_X and CO emission standards given in **Specific Conditions 11, 14 and 16**, respectively above. Each CEMS, COMS and diluent monitor shall be installed, calibrated and properly functioning within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup and prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO, NO_X or opacity emission limits (and subject to the specified averaging period) the permittee shall notify the Compliance Authority. The permittee shall comply with the CEMS, COMS and other continuous monitoring requirements specified in Appendix CEMS of this permit.

a. NO_X CEMS: The NO_X CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR Part 75 in a manner sufficient to demonstrate continuous compliance with the NO_X emission limit specified in **Specific Condition 14** of this subsection. Recordkeeping and reporting shall be conducted pursuant to Subpart Db in 40 CFR 60 and Subparts F and G in 40 CFR 75.
[Rule 62-4.070(3), F.A.C. and NSPS 40 CFR 60, Subpart Db]

b. CO CEMS: The CO CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A in a manner sufficient to demonstrate continuous compliance with the CO emission limit specified in **Specific Condition 16** of this subsection. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards. [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

c. COMS: The COMS shall be installed, calibrated, operated, and maintained in the char combustor exhaust stack in a manner sufficient to demonstrate continuous compliance with the opacity standard specified in **Specific Condition 11** of this subsection. For the COMS, the 6-minute block averages shall begin at the top of each hour. Recordkeeping and reporting shall be conducted pursuant to Subpart Db in 40 CFR 60. [Rule 62-4.070(3), F.A.C.; NSPS 40 CFR 60, Subpart Db]

d. Diluent Monitor: The O_2 or CO_2 content of the flue gas shall be monitored at the locations where NO_X, CO and opacity are continuously monitored or measured. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 60, Subpart 75.

19. Pressure Drop: The permittee shall maintain and calibrate a device which continuously measures and records the pressure drop across each baghouse compartment controlling the PM emissions from the char combustor. Records shall be maintained on site and made available upon request. [Rule 62-4.070(3)]

20. Bag Leak Detection: The permittee shall maintain continuous operation of bag leak detection systems on the char combustor baghouse including keeping records of the systems measurements. Baghouse leak detection records shall be kept on site and made available upon request. [Rule 62-4.070(3) F.A.C.].

21. SNCR Ammonia Injection: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a flow meter to measure and record the ammonia injection rate for the SNCR system for the char combustor. The permittee shall document the general range of NH_3 flow rates required to meet the NO_X limit given in **Specific Condition 14** above over the range of load conditions by comparing NO_X emissions with ammonia flow rates. During NO_X CEMS downtimes or malfunctions, the permittee shall operate at an NH_3 flow rate that is consistent with the documented flow rate for the given load condition. Records shall be maintained on site and made available upon request. [Rule 62-4.070(3) F.A.C.]

22. Opacity Compliance Tests: The sand silo (during sand loading) and char combustor stack shall be tested for a duration of 3 hours in accordance with §60.48b to demonstrate initial compliance with the opacity standard specified in **Specific Conditions 11 and 12** of this subsection within 60 days after achieving permitted capacity, but no later than 180 days after initial operation of the unit. During each federal fiscal year (October 1st to September 30th), the sand silo baghouse shall be tested for duration of 3 hours during sand loading in accordance with EPA Method 9 to demonstrate compliance with the opacity standard. After the initial test, compliance with the opacity limit for the char combustor stack shall be by COMS. [Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]

23. NH_3, CO, PM/PM_{10}, NO_X and SO_2 Compliance Tests: The char combustor exhaust stack shall be tested to demonstrate initial compliance with the NH_3 slip, CO, PM/PM_{10}, NO_X and SO_2 emission limits within 60 days after achieving permitted capacity, but no later than 180 days after initial operation of the unit. During each federal fiscal year (October 1st to September 30th), the char combustor stack be tested to demonstrate compliance with the NH_3, PM/PM_{10} and SO_2 emission limits. [Rule 62-4.070(3), F.A.C.]

24. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

25. Test Methods: Any required stack tests shall be performed in accordance with the following methods.

C. Char Combustor Sand Heater with NG Startup Burner (EU-003)

Method	Description of Method and Comments
EPA 1 - 4	Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis and Moisture Content. Methods shall be performed as necessary to support other methods.
EPA 5, 5B, 17	Determination of Particulate Emissions.
EPA 6C	Measurement of SO_2 Emissions (Instrumental).
EPA 7E	Determination of NO_X Emissions (Instrumental).
EPA 9	Visual Determination of Opacity.
EPA 10	Measurement of Carbon Monoxide Emissions (Instrumental).
EPA 18	Measurement of Gaseous Organic Compound Emissions (Gas Chromatography). *{For concurrent use with EPA Method 25A to deduct emissions of methane and ethane from the THC emissions measured by Method 25A.}*
EPA 19	Calculation Method for NO_X, PM, and SO_2 Emission Rates.
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source.

RECORDS AND REPORTS

26. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. For each test run, the report shall also indicate the operating rate. [Rule 62-297.310(8), F.A.C.]

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
004	BPG Cleanup System and Flare/TO System: This EU consists of two principal components each of which is briefly described below. • *BPG Cleanup System*: The BPG cleanup system consists of specialized oil scrubbers and an aqueous scrubber with a caustic section. The cooled raw BPG from the gasifier/coarse solids cyclone (EU-002) is treated to remove tars and finer particles in an oil-based gas washer. Tars are returned to support combustion in the char combustor (EU-003). Removal of ammonia (NH_3), hydrogen sulfide (H_2S) and hydrogen chloride (HCl) is accomplished in a wet scrubber that will include a section that will scrub H_2S using caustic soda (NaOH). Cooled, sweetened, and cleaned BPG is then compressed or boosted for delivery to the SOLAR T-130 CTG (EU-011,012 and 013), GE MS6001B CTG (EU 009) or flare/TO system (EU-004). • *BPG flare or TO system*: The flare or TO system shall only be used to combust BPG during startup, planned shutdown and emergency shutdown (e.g. CTG/DB or gasifier trips). Raw (uncleaned) BPG from the biomass gasifier (EU-002) may be combusted in the flare/TO and not sent to the BPG cleanup system (EU-005) for a maximum of 200 hours per year during startup, planned shutdown, and emergency shutdown (e.g. CTG or gasifier trips)as stipulated in **Specific Condition 4** of this subsection. Cleaned, sweetened BPG from the cleanup system may be combusted in the flare/TO for up to 200 hours per year during startup, planned shutdown, and emergency shutdown (e.g. CTG or gasifier trips) as stipulated in **Specific Condition 4** of this subsection and not further processed for use in the SOLAR T-130 CTG (EU-011,012 and 013), GE MS6001B CTG (EU 009). The 200 hours per year operation limit for the flare system is the combined usage when flaring "raw" or "clean" BPG.

EQUIPMENT

1. BPG Cleanup System: The permittee is required to construct a BPG cleanup system consisting of the following control equipment. None of the control equipment shall discharge directly to the ambient air.
   a. Oil Based Scrubber: A two-stage scrubber that utilizes specialized oils and is designed to remove heavy tars in the first stage and light tars in the second stage. The heavy and light tars are then recycled back to the char combustor.
   b. Aqueous Scrubber: An aqueous scrubber that is designed to remove inorganic impurities.
   [Application No. 0450012-002-AC and Rule 62-4.070(3), F.A.C.]
2. Flare/TO System: The permittee is authorized to construct a BPG flare or TO system to combust the raw BPG or "cleaned" BPG. Each system shall have continuous pilots and combustion chambers to destroy unused BPG. The presence of a flare/TO pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.
   [Application No. 0450012-0021-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

3. Maximum Capacity: The flare or TO system shall combust BPG with a maximum heat input rate of 518.0 mmBtu/hour. NG shall be used as fuel for the pilots.
   [Application No. 0450012-002-AC and Rule 62-210.200(PTE), F.A.C.]
4. Hours of Operation: The hours of operation of the BPG cleanup system are not limited. The hours of operation of the flare or TO system are limited to 200 hours per year (hr/yr) at the maximum capacity in any consecutive 12 month period. If the flare/TO is fired at less than the maximum capacity the operational hours shall be prorated. For example, if the flare is operated at 80% capacity for 20 hours the prorated

hours for compliance purposes is 16 hours (20 x 0.8 = 16). The flare or TO system shall only be used to combust BPG gas during startup, planned shutdown, and emergency shutdown (e.g. CTG or gasifier trips). [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

5. Circumvention: The permittee shall not circumvent the BPG cleanup system except during startup, planned shutdown, and emergency shutdown (e.g. CTG or gasifier trips).
[Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.650, F.A.C.]

TAR HANDLING AND STORAGE

6. Tars shall be continuously returned to the char combustor and not accumulated, stored or disposed of on-site or off-site. [Application No. 0450012-002-AC and Rule 62-4.070(3), F.A.C.]

EMISSIONS STANDARDS

7. Visible Emissions (VE) Standard: The flare or TO system shall be designed for and operated with a VE of 10% opacity. [Rule 62-4.070(3), F.A.C.]

TESTING AND MONITORING REQUIREMENTS

8. VE Compliance Tests: The flare or TO exhaust shall be tested to demonstrate initial compliance with the VE standard given in **Specific Condition** 7 of this subsection within 60 days after achieving permitted capacity, but no later than 180 days after initial operation of the unit and during each federal fiscal year (October 1st to September 30th) thereafter. An EPA Method 9 or 22 VE compliance test shall be used to determine the compliance of the TO or flare system, respectively, with the VE standard. The observation period is 3 hours and shall be used according to Method 9 or 22. [Rule 62-4.070(3), F.A.C.]

9. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

10. Test Methods: Any required flare/TO tests shall be performed in accordance with the following methods:

Method	Description of Method and Comments
EPA 9	Visual Determination of the Opacity of Emissions from Stationary Sources
EPA 22	Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares 2 Hour Duration

11. Work Practice: Good combustion practices will be utilized at all times to ensure emissions from the flare or TO system are minimized. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of these systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. The flare/TO pilots shall be operated with a flame present at all times.
[Rules 62-4.070(3) F.A.C.]

RECORDS AND REPORTS

12. Records: The permittee shall record in a written log the duration of each flare/TO event and the reason for flaring. If requested by the Compliance Authority, the permittee shall provide a copy of these records or a summary of these records. [Rule 62-4.070(3), F.A.C.]

13. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit.
[Rule 62-297.310(8), F.A.C.]

E. Compressor and STG Cooling Towers (EU-005)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
005	Compressor and STG cooling towers

EQUIPMENT DESIGN

1. Cooling Tower Design: The permittee is authorized to construct a cooling tower system consisting of two cooling towers. One tower is for the STG while the other is for the cooling of compressor gases. The power block cooling tower is based on a wet surface air condenser with a water flow rate of approximately 7,050 gallons per minute (gpm). The compressor gases cooling tower is based on a traditional surface heat exchanger with a water flow rate of approximately 3,800 gpm. The STG cooling tower uses mist eliminators and shall have a drift rate of 0.002% of the circulating water flow rate while the compressor gases cooling tower uses mist eliminators and shall have a drift rate of 0.005%. The difference in condenser technology accounts for the differences in design drift rates.
[Application No. 0450012-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

2. Hours of Operation: Operation of the cooling towers is not restricted (8,760 hours per year). [Application No. 0450012-001-AC and Rule 62-210.200 (PTE), F.A.C.]
3. Circulating Water Flow Rate: Upon request, the applicant shall provide a means for determining the circulating water flow rate through each cooling tower. [Rule 62-4.070, F.A.C.]
4. Drift Rate: The permittee shall provide certification along with the application for Title V air operation permit that the cooling towers were constructed and installed to the meet the drift rates specified in **Specific Condition 1** of this subsection. After this certification is provided, the cooling tower will be considered an unregulated emissions unit. [Rules 62-4.070 and 62-210.200 (PTE), F.A.C.]
5. Chromium-Based Water Treatment Chemicals: 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.
[Rule 62-4.070, F.A.C. and NESHAP40 CFR 63, Subpart Q]

F. Auxiliary Boiler (EU-006)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
006	Auxiliary boiler: The auxiliary boiler fires NG with a maximum heat input rate of 62 mmBtu/hour to start up the biomass gasification system. Exhaust gases exit a stack with design parameters of 2.75 feet in diameter, 50 feet in height, and a flow rate of 29,000 actual cubic feet per minute (acfm) and an exit temperature of 296 degrees °F.

EQUIPMENT

1. Auxiliary Boiler: The permittee is authorized to install an auxiliary boiler rated at 62 mmBtu/hour of heat input from firing NG, biodiesel or ULSD fuel oil. The auxiliary boiler shall only be operated for purposes of starting up the gasification system. [Application No. 0450012-002-AC]

PERFORMANCE RESTRICTIONS

2. Authorized Fuel: The auxiliary boiler shall fire only NG with a maximum fuel sulfur content of 2 grains/100 scf. [Application No. 0450012-002-AC; Rules 62-210.200(PTE) and 62-296.406(BACT) F.A.C.]
3. Permitted Capacity: The maximum heat input rate of the auxiliary boiler is 62 mmBtu/hour based on a 4-hour average. [Application No. 0450012-002-AC and Rule 62-210.200(PTE), F.A.C.]
4. Hours of Operation: The auxiliary boiler shall operate no more than 500 hours at permitted capacity in any consecutive 12 month period. If the boiler is fired at less than the permitted capacity the operational hours shall be prorated. For example, if the boiler is operated at 80% capacity for 20 hours the prorated hours for compliance purposes is 16 hours (20 x 0.8 = 16). [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

REGULATORY APPLICABILITY

5. Small Boiler BACT: 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. [Rule 62-296.406, F.A.C.]
6. NSPS Subpart Dc and Subpart A Applicability: The auxiliary boiler is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial or Institutional Boilers and Subpart A General Provisions. Specifically, this emission unit shall comply with 40 CFR 60.48c Reporting and Recordkeeping Requirements. The applicable conditions are given in Appendices A and Dc of this permit.
[Rule 62-204.800(7)(b) and 40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units and 40 CFR 60 Subpart A, General Provisions]

EMISSIONS STANDARDS

7. Opacity Standard: In accordance with EPA Method 9, for a test duration of three hours, VE shall not exceed 5% opacity except for one 6-minute period per hour that shall not exceed 15% opacity. [Application No. 0450012-002-AC and Rule 62-4.070(3) F.A.C.]

TESTING AND MONITORING REQUIREMENTS

8. Initial Compliance Tests: As determined by EPA Method 9, the emissions unit shall be tested to demonstrate initial compliance with the opacity standard given in **Specific Condition 7** of this subsection within 60 days after achieving permitted capacity, but no later than 180 days after initial operation of the unit. [Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]

9. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the emissions unit shall be tested in accordance with EPA Method 9 to demonstrate compliance with the opacity standard given in **Specific Condition** 7 of this subsection. [Rule 62-297.310(7)(a)4, F.A.C.]

10. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

RECORDS AND REPORTS

11. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. For each test run, the report shall also indicate the heat input rate. [Rule 62-297.310(8), F.A.C.]

G. Emergency Generator (EU-007)

This section of the permit addresses the following emissions units.

EU ID No.	Emission Unit Description
007	One emergency diesel generator with a maximum design rating of 500 kilowatts (kW)

EQUIPMENT

1. Emergency Generator: The permittee is authorized to install, operate, and maintain one emergency generator with a maximum design rating of 500 kW (671 horsepower (hp)) or smaller.
[Application No. 0450012-002-AC; Rule 62-210.200 (PTE), F.A.C.]

2. Biodiesel and ULSD Fuel Oil Storage Tanks: The permittee is authorized to construct tanks to store biodiesel and ULSD fuel oil for use in the emergency generator.
[Applicant request and 62-4.070(3), Reasonable Assurance]
{Permitting Note: The biodiesel and ULSD fuel oil storage tanks for use in the emergency generator at the NWFREC facility are not subject to NSPS Subpart Kb because each stores a liquid (biodiesel and ULSD fuel oil) with a maximum true vapor pressure less than 3.5 kPa (0.51 pounds per square inch (psi)). Accordingly the tanks are unregulated emissions units.} [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

NSPS AND NESHAP APPLICABILITY

3. NSPS Subpart IIII Applicability: This emergency generator is a Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII, including emission testing or certification. [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]

4. NESHAPS Subpart ZZZZ Applicability: The emergency generator is a Liquid Fueled Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the generators must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.
[40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)]

PERFORMANCE RESTRICTIONS

5. Hours of Operation: The emergency generator may operate up to 500 hours per year for maintenance and testing purposes. [Application No. 0450012-002-AC and Rule 62-210.200 (PTE), F.A.C.]

6. Authorized Fuel: The emergency generator shall fire biodiesel or ULSD fuel oil only. The biodiesel must meet the ASTM specification given in Appendix ASTM of this permit.
[Application No. 0450012-002-AC and Rule 62-210.200 (PTE), F.A.C.]

EMISSION STANDARDS

7. Emissions Limits: The emergency generator shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII. A link to the full text of Subpart IIII is given in Appendix IIII of this permit. Manufacturer certification, when using USLD fuel oil and, if available, biodiesel, can be provided to the Department in lieu of actual stack testing.

Emergency Generator ($\geq$ 450 kW and $\leq$ 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	0.2	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 fuel oil in the emergency generator with vendor certification of sulfur (S) content of 0.0015% or less.
3. NMHC means Non-Methane Hydrocarbons.

[Application No. 0450012-002-AC; NSPS 40 CFR 60, Subpart IIII; Rule 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

8. Notification, Recordkeeping and Reporting Requirements: The permittee shall adhere to the compliance testing and certification requirements listed in 40 CFR 60.4211 and maintain records demonstrating fuel usage and quality. [40 CFR 60.4211]

H. Emergency Fire Pump Engine (EU-008)

This section of the permit addresses the following emissions unit.

EU ID No.	Emission Unit Description
008	One emergency diesel fire pump engine with a maximum design rating of 250 kW

EQUIPMENT

1. Engine Driven Fire Pump: The permittee is authorized to install, operate, and maintain one emergency fire pump engine. The pump engine will have a maximum rating of 250 kW (335 hp) or smaller. [Application No. 0450012-002-AC and Rule 62-210.200(PTE), F.A.C.]
2. Biodiesel and ULSD Fuel Oil Storage Tanks: The permittee is authorized to construct tanks to store biodiesel and ULSD fuel oil for use in the emergency fire pump engine.
[Applicant request and 62-4.070(3), Reasonable Assurance]
{Permitting Note: The biodiesel and ULSD fuel oil storage tanks for use in the emergency fire pump engine at the NWFREC facility are not subject to NSPS Subpart Kb because each stores a liquid (biodiesel and ULSD fuel oil) with a maximum true vapor pressure less than 3.5 kPa (0.51 pounds per square inch (psi)). Accordingly the tanks are unregulated emissions units.} [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

NSPS AND NESHAP APPLICABILITY

3. NSPS Subpart IIII Applicability: The emergency fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII.
[40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]
4. NESHAP Subpart ZZZZ Applicability: The emergency fire pump engine is a Liquid Fueled Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the emergency fire pump engine must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.
[40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)]

PERFORMANCE RESTRICTIONS

5. Hours of Operation: The emergency fire pump engine may operate up to 250 hours per year for maintenance and testing purposes. The duration of each maintenance and testing event shall not exceed.
[Application No. 0450012-002-AC and Rule 62-210.200 (PTE), F.A.C.]
6. Authorized Fuel: This unit shall fire biodiesel or ULSD fuel oil only. The biodiesel must meet the ASTM specification given in Appendix ASTM of this permit.
[Application No. 0450012-002-AC and Rule 62-210.200 (PTE), F.A.C.]

EMISSION STANDARDS

7. Emissions Limits: The emergency fire pump engine shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII. A link to the full text of Subpart IIII is given in Appendix IIII of this permit. Manufacturer certification, when using ULSD fuel oil and, if available, biodiesel, may be provided to the Department in lieu of actual testing. [40 CFR 60.4211 and Rule 62-4.070(3), F.A.C.]

Emergency Pumps (≥ 300 hp and < 600 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 fuel oil in the fire pump engine with vendor certification of S content of 0.0015% or less.

[Application No. 0450012-002-AC; 40 CFR 60, NSPS 40 CFR 60, Subpart IIII; Rule 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

8. Notification, Recordkeeping and Reporting Requirements: The permittee shall adhere to the compliance testing and certification requirements listed in 40 CFR 60.4211 and maintain records demonstrating fuel usage and quality. [40 CFR 60.4211]

I. BPG-Fueled CTG and HRSG (EU-009, EU-010 and EU-011)

This section of the permit addresses the following emissions units.

ID No.	Emission Unit Description
009	One 15.7 MW BPG-fueled SOLAR T-130 CTG and HRSG **or** one 45.6 MW BPG-fueled GE Model MS6001B CTG and HRSG. Steam from the HRSG is used in the shared 19.5 (GE) or 19.6 (SOLAR) MW STG
010	One 15.7 MW BPG-fueled SOLAR T-130 CTG and HRSG. Steam from the HRSG is used in the shared 19.6 MW STG.
011	One 15.7 MW BPG-fueled SOLAR T-130 CTG and HRSG. Steam from the HRSG is used in the shared 19.6 MW STG.

EQUIPMENT

1. CTG/HRSG Unit Options:
   a. *SOLAR CTG Option*: The permittee is authorized to install, tune, operate and maintain a combined cycle CTG system consisting of the following equipment: a BPG and NG compressor system; 15.7 MW BPG-fueled SOLAR T-130 CTG; three inlet air filtration and chiller systems; three automated CTG control systems; three HRSG; three HRSG stacks; and a shared 19.6 MW STG. NG, biodiesel or ULSD fuel oil will be used during commissioning and during startups, malfunctions and shutdowns. [Application No. 0450012-002-AC and Rule 62-4.070(3), F.A.C.]
   b. *GE CTG Option*: In lieu of the SOLAR CTG option given in **Specific Condition 1a** above of this subsection, the permittee is authorized to install, tune, operate and maintain a combined cycle CTG system consisting of the following equipment: a BPG and NG compressor system; one 45.6 MW BPG-fueled GE Model MS6001B CTG; an inlet air filtration and chiller system; an automated CTG control system; one HRSG; one HRSG stack; and a 19.5 MW STG. NG, biodiesel or ULSD fuel oil will be used during commissioning and during startups, malfunctions and shutdowns. [Application No. 0450012-002-AC and Rule 62-4.070(3), F.A.C.]
2. Wet Injection: The permittee shall install, operate, and maintain a wet injection system (water or steam) to reduce NO_X emissions from each SOLAR CTG or the GE CTG. Prior to the initial emissions performance tests required for a CTG, the wet injection system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional oxidation catalyst and SCR control technology described below. Thereafter, the CTG(s) shall be maintained and tuned in accordance with the manufacturer's recommendations. [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
3. Selective Catalytic Reduction (SCR) Systems: The permittee shall install an SCR system for each CTG/HRSG exhaust stream to control NO_X emissions. Each SCR system will consist of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. Each SCR system shall be designed, constructed and operated to achieve the permitted levels of NO_X emissions indicated in this subsection. The SCR systems shall be designed to achieve a maximum ammonia slip level of 10 parts per million by volume dry (ppmvd) @ 15% oxygen. [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

   {Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}
4. Oxidation Catalyst Systems: The permittee shall install an oxidation catalyst system for each CTG/HRSG exhaust stream to control CO and VOC emissions. Each oxidation catalyst system shall be designed, constructed and operated to achieve the permitted levels of CO and VOC emissions specified in the

subsection.
[Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

5. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. Ammonia shall be injected as necessary to ensure compliance with the permitted levels of NO_X emissions specified in this subsection.
[Rules 62-210.650 and 62-4.070(3), F.A.C.]

6. Biodiesel and ULSD Fuel Oil Storage Tanks: The permittee is authorized to construct tanks to store biodiesel and ULSD fuel oil for use during CTG during startup.
[Applicant request and 62-4.070(3), Reasonable Assurance]

{Permitting Note: The biodiesel and ULSD fuel oil storage tanks for CTG startup at the NWFREC facility are not subject to NSPS Subpart Kb because each stores a liquid (biodiesel and ULSD fuel oil) with a maximum true vapor pressure less than 3.5 kPa (0.51 pounds per square inch (psi)). Accordingly, the tanks are unregulated emissions units.} [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

7. NO_X CEMS: In accordance with §60.4335(b) and §60.4345, the permittee shall install, calibrate, operate and maintain a CEMS to continuously monitor and record NO_X emissions from the CTG exhaust stream within 60 calendar days after achieving permitted capacity but no later than 180 calendar days after initial startup.
[Application No. 0450012-002-AC; Rule 62-4.070(3), F.A.C.; and NSPS 40 CFR 60, Subpart KKKK in 40 CFR 60]

8. CO CEMS: The permittee shall install, calibrate, operate and maintain a CEMS to continuously monitor and record CO emissions from the CTG exhaust stream within 60 calendar days after achieving permitted capacity but no later than 180 calendar days after initial startup.
[Application No. 0450012-002-AC and Rule 62-4.070(3), F.A.C]

PERFORMANCE RESTRICTIONS

9. Authorized Fuels: The only authorized fuels for the CTG are: BPG from the cleanup system; NG; biodiesel (if available); and, ULSD fuel oil. The biodiesel must meet the ASTM specification given in Appendix ASTM of this permit.
[Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

10. Permitted CTG Capacities: The maximum heat input rate of each SOLAR CTG is 173 mmBtu/hour on a 1 hour average basis. The maximum heat input rate of the GE CTG is 514 mmBtu/hour on a 1 hour average basis. These heat rates are based on a compressor inlet temperature of 59 °F, International Organization for Standardization (ISO) conditions, and the lower heating value (LHV) of the BPG or NG. Heat input rates will vary depending upon CTG characteristics, ambient conditions and alternate methods of operation. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.
[Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

{Permitting Note: The estimated LHV for BPG is 435 British thermal unit per standard cubic foot (Btu/scf) and 980 Btu/scf for NG. On average, the LHV of ULSD fuel oil is 128,450 Btu/gal and 119,550 Btu/gal for biodiesel.}

11. Hours of Operation: The CTG shall fire NG, biodiesel or ULSD fuel oil for the purpose of startup no more than a combined 750 hours at permitted capacity during any consecutive 12 month period. When firing the CTG at less than the permitted capacity, fuel usage shall be prorated over the hours of operation by reducing the hours when firing the fuel based on the percentage of the fired capacity compared to the

maximum, e.g. 90 percent (5 hours x 0.9 = 4.5 hours of fuel firing). The hours of operation are not otherwise limited (8,760 hours per year).
[Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

12. Authorized Method of Operation: The CTG are permitted to operate only as part of a combined cycle system. [Application No. 0450012-002-AC]

NSPS APPLICABILITY

13. NSPS Subpart KKKK and Subpart A Applicability: The CTG (SOLAR or GE) are subject to all applicable requirements of 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines which applies to CTG constructed after February 18, 2005 and Subpart A, General Provisions. [Rule 62-204.800(7)(b), F.A.C.; 40 CFR 60.4300, NSPS - Subpart KKKK - Standards of Performance for Stationary Combustion Turbines (see Appendix KKKK of this permit) and 40 CFR 60 Subpart A, General Provisions (see Appendix A of this permit)].

EMISSION LIMITS

14. Emission Standards: The following standards are at least as stringent as the Subpart KKKK limits described in **Specific Condition 13** of this subsection and in Appendix KKKK of this permit. These also include more stringent limits to insure that the facility PSD pollutant emissions are less than the respective major stationary source thresholds. Emissions shall not exceed the following standards for each CTG/HRSG unit option (SOLAR or GE):

For each SOLAR Model T-130 CTG/HRSG Unit			
Parameter	**Limit [a]**	**Basis**	**Compliance**
NO_X [b]	74 ppmvd @ 7% O_2	NSPS Subpart KKKK	30 day rolling average by CEMS
	25 ppmvd @ 7% O_2	NSPS Subpart KKKK	30 day rolling average by CEMS
	8.99 lb/hr/118.1 TPY	Applicant Request	30 day rolling average by CEMS
SO_2/SAM [c]	0.15 lb/mmBtu	NSPS Subpart KKKK	Total Sulfur (TS) Fuel Monitoring
	0.060 lb/mmBtu	NSPS Subpart KKKK	Fuel Monitoring Exemption Limit
	0.91 lb/hr/11.9 TPY	Applicant Request	TS Fuel Monitoring
CO [d]	5.5 lb/hr/72.3 TPY	Applicant Request	30 day rolling average by CEMS
PM/PM_{10} (filterable) [e]	4.7 lb/hr/61.8 TPY	Applicant Request	Initial and Annual Stack Test
Visual Emission (VE)	VE shall not exceed 10% opacity for each 6-minute block average.	Rule 62-4.070(3), F.A.C.	Initial and Annual Stack Test
VOC [f]	1.0 lb/hr	Applicant Request	Initial and Annual Stack Test
NH_3 Slip [g]	10 ppmvd @ 7% O_2	Rule 62-4.070(3), F.A.C.	Initial and Annual Stack Test
Heat Input Rate	173 mmBtu/hour	Rule 62-210.200(PTE), F.A.C.	1-hour rolling average @ 59 °F, Heat Input per 40 CFR 75, App. F
For the GE Model MS6001B CTG/HRSG Unit			
Parameter	**Limit [a]**	**Basis**	**Compliance**
NO_X [b]	74 ppmvd @ 7% O_2	NSPS Subpart KKKK	30 day rolling average by CEMS
	25 ppmvd @ 7% O_2	NSPS Subpart KKKK	30 day rolling average by CEMS
	26.97 lb/hr/118.1 TPY	Applicant Request	30 day rolling average by CEMS
SO_2/SAM [c]	0.15 lb/mmBtu	NSPS Subpart KKKK	TS Fuel Monitoring
	0.060 lb/mmBtu	NSPS Subpart KKKK	Fuel Monitoring Exemption Limit
	2.73 lb/hr/11.9 TPY	Applicant Request	TS Fuel Monitoring

Parameter	Limit [a]	Basis	Compliance
CO [d]	16.5 lb/hr/72.3 TPY	Applicant Request	30 day rolling average by CEMS
PM/PM_{10} (filterable) [e]	14.1 lb/hr/61.8 TPY	Applicant Request	Initial and Annual Stack Test
VE [f]	VE shall not exceed 10% opacity for each 6-minute block average.	Rule 62-4.070(3), F.A.C.	Initial and Annual Stack Test
VOC [g]	3.0 lb/h/13.1 TPY	Applicant Request	Initial and Annual Stack Test
NH_3 Slip [h]	10 ppmvd @ 7% O_2	Rule 62-4.070(3), F.A.C.	Initial and Annual Stack Test
Heat Input Rate	514 mmBtu/hour	Rule 62-210.200(PTE), F.A.C.	1-hour rolling average @ 59 °F, Heat Input per 40 CFR 75, App. F

a. The mass emission rate standards are based on a turbine inlet condition of 59 °F. Mass emission rate may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department. The TPY limits are total from all three SOLAR CTG or single GE CTG.
b. NO_X: ppmvd @ 7% O_2 means parts per million by volume dry adjusted to 7 percent oxygen. Pound per hour limit for NO_X ensures that NWFREC will not trigger PSD for this pollutant. The 74 ppmvd limit is the Subpart KKKK limit when CTG is firing BPG while the 25 ppmvd limit is when the CTG is firing NG.
c. The 0.15 lb SO_2/mmBtu NSPS Subpart KKKK limit is for units firing 50% or more of biogas. This limit is met by monitoring TS content of the biogas fuel per § 60.4360. If permittee can demonstrate that the SO_2 emission rate for a fuel fired in a unit is 0.060 lb SO_2/mmBtu or less, then TS fuel monitoring is not required by Subpart KKKK for that fuel (See **Specific Condition 19** of this subsection). The TS fuel monitoring effectively limits the potential emissions of SAM and SO_2 from the CTG. To demonstrate that annual SO_2 emissions are less than the major source threshold of 250 TPY, TS fuel monitoring must be conducted per § 60.4360 to show that SO_2 emissions are less than or equal to 0.91 lb/hr on an annualized basis (See **Specific Condition 19** of this subsection). In lieu of fuel testing, the permittee can accept fuel supplier/vendor reports on fuel TS content for NG, biodiesel and ULSD fuel oil.
d. Pound per hour limit for CO ensures that NWFREC will not trigger PSD for this pollutant.
e. Filterable (F) fraction as measured by EPA Method 5. An initial test using EPA Methods 5 and 202 will be conducted to determine the F and condensable (C) PM emission rate, but no emission limit will be set for (F+C) PM.
f. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.
g. Pound per hour limit for VOC ensures that NWFREC will not trigger PSD for this pollutant.
h. Ammonia slip caused by the SCR system. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

[Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EXCESS EMISSIONS

15. Excess Emissions Calculations: The following conditions apply only to the SIP based emissions standards specified above in this subsection. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal NSPS, NESHAP, or Acid Rain provision. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions supersede the provisions in Rule 62-210.700(1), F.A.C.
    a. *CO Emissions Standards*: Due to the long term nature of the CO limit (30 day rolling average), no excess emissions provisions are made for excess CO emissions.
    b. *NO_X Emissions*: Excess NO_X emissions based on the 30 day rolling average standard shall be calculated in accordance with the NSPS Subpart KKKK provisions.
    c. *Opacity*: As determined by EPA Method 9, visible emissions from the CTG during startup and shutdown shall not exceed 20% opacity based on 6-minute averages. Excess visible emissions resulting from malfunction 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.
16. Definitions Related to Excess Emissions: Rule 62-210.200(Definitions), F.A.C. defines the following terms.
    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.
    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.

c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

17. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

18. CEMS: The permittee shall install, calibrate, maintain and operate CEMS and a diluent monitor to measure and record the emissions of CO and NO_X and oxygen (O_2) or carbon dioxide (CO_2) from each CTG in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated and properly functioning within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup and prior to the initial performance tests. Within one working day of discovering emissions in excess of the CO or NO_X standards (and subject to the specified averaging period), the permittee shall notify the Compliance Authority. See Appendix CEMS of this permit for additional CEMS requirements.

a. *NO_X CEMS:* The NO_X CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

b. *CO CEMS:* The CO CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

c. *Diluent Monitor:* The O_2 or CO_2 content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

GENERAL MONITORING REQUIREMENTS

19. Fuel Sulfur Monitoring: The permittee shall conduct total sulfur testing for each authorized fuel (see **Specific Condition 9** of this subsection) fired in the CTG to demonstrate compliance with the fuel total sulfur (TS) provisions of § 60.4360 in NSPS 40 CFR 60, Subpart KKKK. In addition, the permittee shall sample and analyze the BPG for heating value at least once per week utilizing ASTM Method D3588 - 98(2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels or an equivalent method approved by the Compliance Authority.

Per § 60.4365, the permittee may elect **not** to monitor the TS content of each fuel combusted in the CTG, if each fuel is demonstrated not to exceed a potential sulfur emission rate of 0.060 lb SO_2/mmBtu of heat input. To demonstrate for each fuel that the sulfur emission rate does not exceed 0.060 lb SO_2/mmBtu of heat input, representative fuel sampling data is required that at a minimum meets the requirements of Section 2.3.1.4 or 2.3.2.4 of 40 CFR 75, Appendix D – Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units.

To demonstrate that annual SO_2 emissions are less than the 250 TPY major source threshold, TS fuel monitoring must be conducted per § 60.4360 to show that SO_2 emissions are less than or equal to 0.91 lb/hr for each SOLAR CTG or 2.73 lb/hr for GE CTG on an annualized basis. In lieu of fuel testing, the permittee can accept fuel supplier/vendor reports on fuel TS content for NG, biodiesel and ULSD fuel oil. [Application No. 0450012-002-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.; NSPS 40 CFR 60, Subpart KKKK]

20. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to each SCR system prior to the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the CTG load condition. [Rules 62-4.070(3)]

PERFORMANCE TESTS

21. Initial Compliance Tests: Each CTG shall be tested to demonstrate initial compliance with the emissions standards for CO, NO_X, PM/PM_{10}, VE, VOC and ammonia slip. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the unit. Each CTG shall demonstrate compliance with the NO_X standard in accordance with the methods specified in NSPS Subpart KKKK of 40 CFR 60. [Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]

22. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each CTG shall be tested to demonstrate compliance with the emissions standards for VOC, PM/PM_{10}, VE and ammonia slip. [Rule 62-297.310(7)(a)4, F.A.C.]

23. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

24. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
EPA 1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
EPA 7E	Determination of NO_X Emissions from Stationary Sources
EPA 9	Visual Determination of the Opacity of Emissions from Stationary Sources.
EPA 10	Determination of CO Emissions from Stationary Sources
EPA 18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography
EPA 19	Determination of SO_2 Removal Efficiency and PM, SO_2 and NO_X Emission Rates Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.
EPA 25	Gaseous Nonmethane Organic Emissions
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source
EPA 320	
EPA 201	Determination of PM_{10} Emissions (Exhaust Gas Recycle Procedure)

The above methods are described in Appendix A of 40 CFR 60 and are adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800 and 62-297.100, F.A.C.; and Appendix A of 40 CFR 60]

RECORDS AND REPORTS

25. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each CTG on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). This shall be achieved through monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of Appendix D in 40 CFR 75 and recording the data using a monitoring component of the CEMS system required above. [Rule 62-4.070(3), F.A.C. and 40 CFR 75]

26. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the previous month and the previous consecutive 12 months: total heat input rate to each CTG from each fuel (mmBtu); the 30 day rolling average in lb/hr of NO_X and CO; and the 12 month rolling total of NO_X and CO emissions in tons. Annual NO_X and CO emissions shall be determined in accordance with Rule 62-210.370, F.A.C. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. Fuel consumption shall be monitored in accordance with the provisions of Appendix D in 40 CFR 75. [Rules 62-4.070(3), F.A.C.]

27. Stack Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Compliance Authority on the results of each such test. The required test report shall be filed with the Compliance Authority as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Compliance Authority to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report shall provide the applicable information specified in Rule 62-297.310(8), F.A.C. and summarized in Appendix D in 40 CFR 75. [Rule 62-297.310(8), F.A.C.]

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.

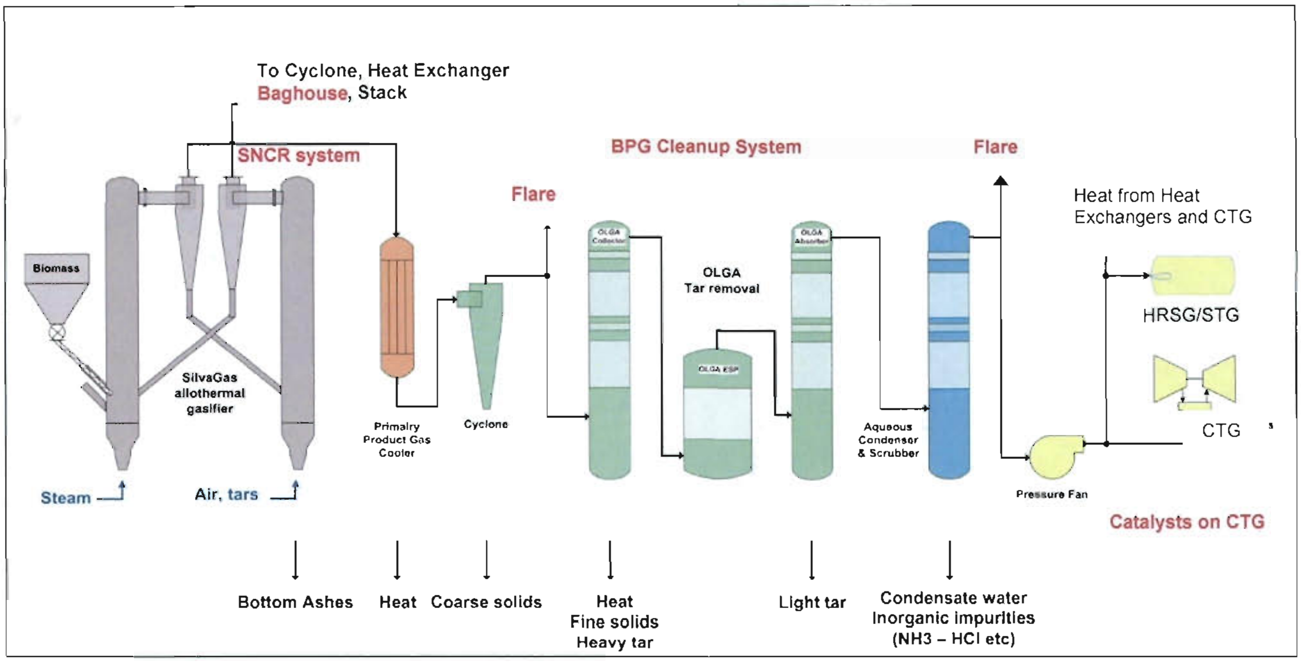

Figure 3. Simplified BGCC Process Diagram including Key Air Pollution Control Systems.

2.1. (EU 001) Fuel Receiving, Storage, Handling, and Drying System

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.

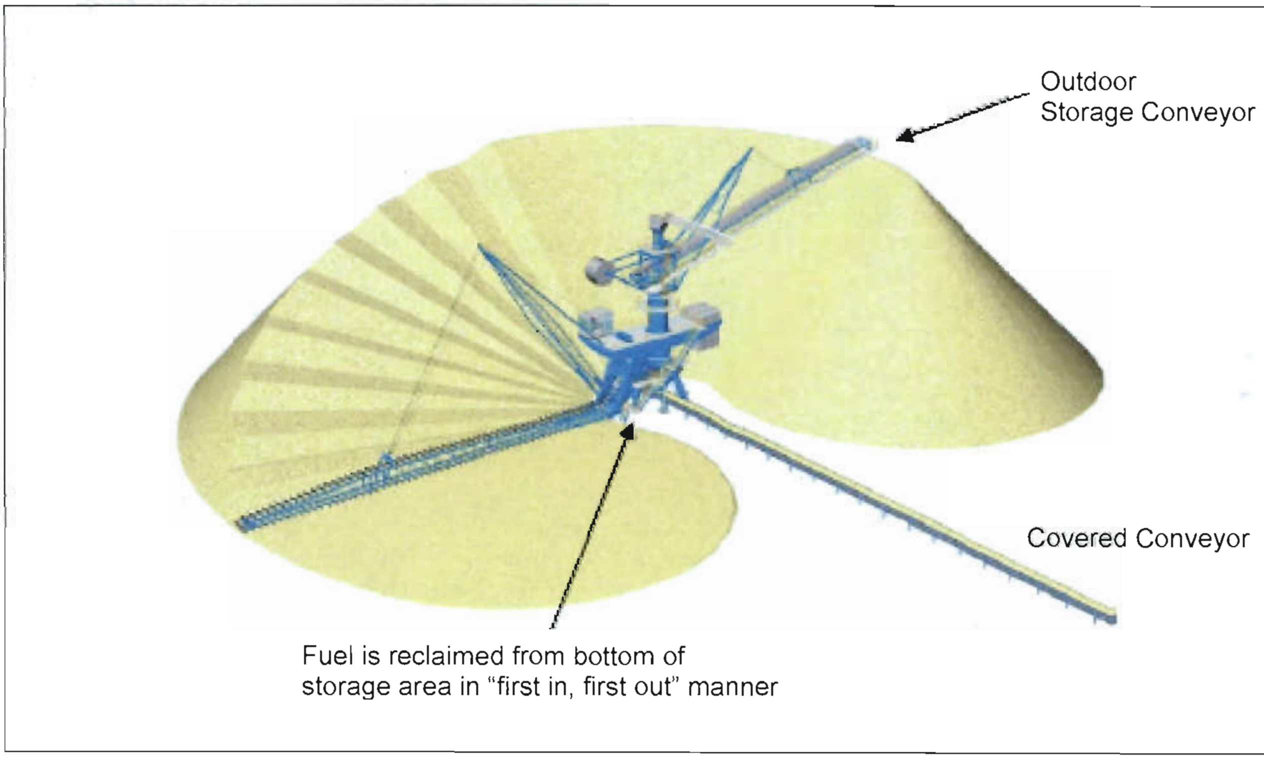

Figure 4. Layout of Kidney-Shaped Pile Operating on Principle of First In/First Out.

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.

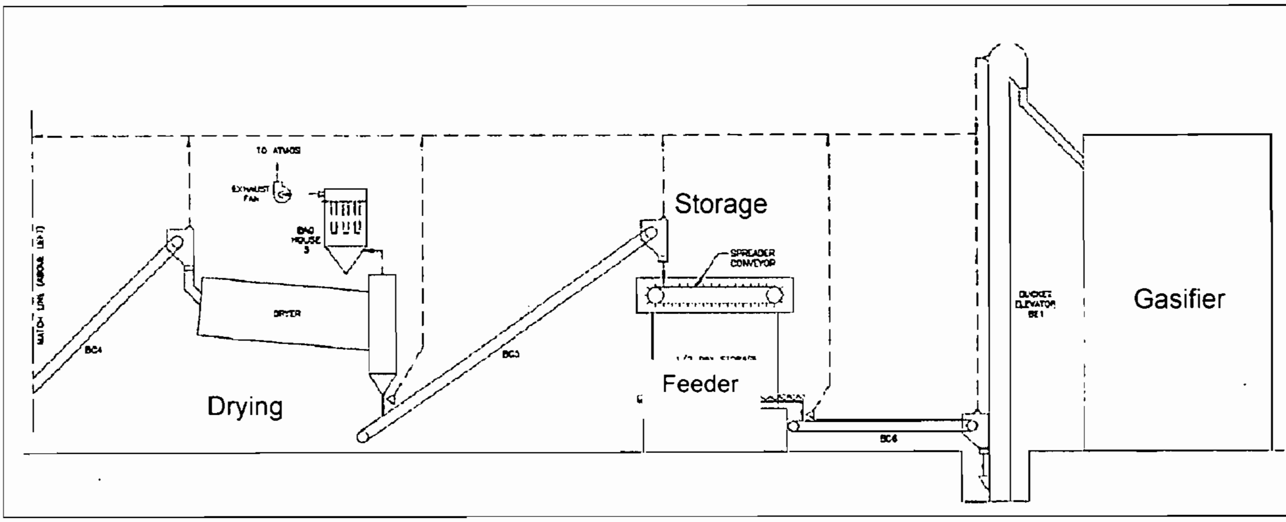

Figure 5. Woody Biomass Drying, Conveyance and Feeding to Gasifier.

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. (EU 002) Gasifier with Startup Burner

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 gasifier.

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:

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

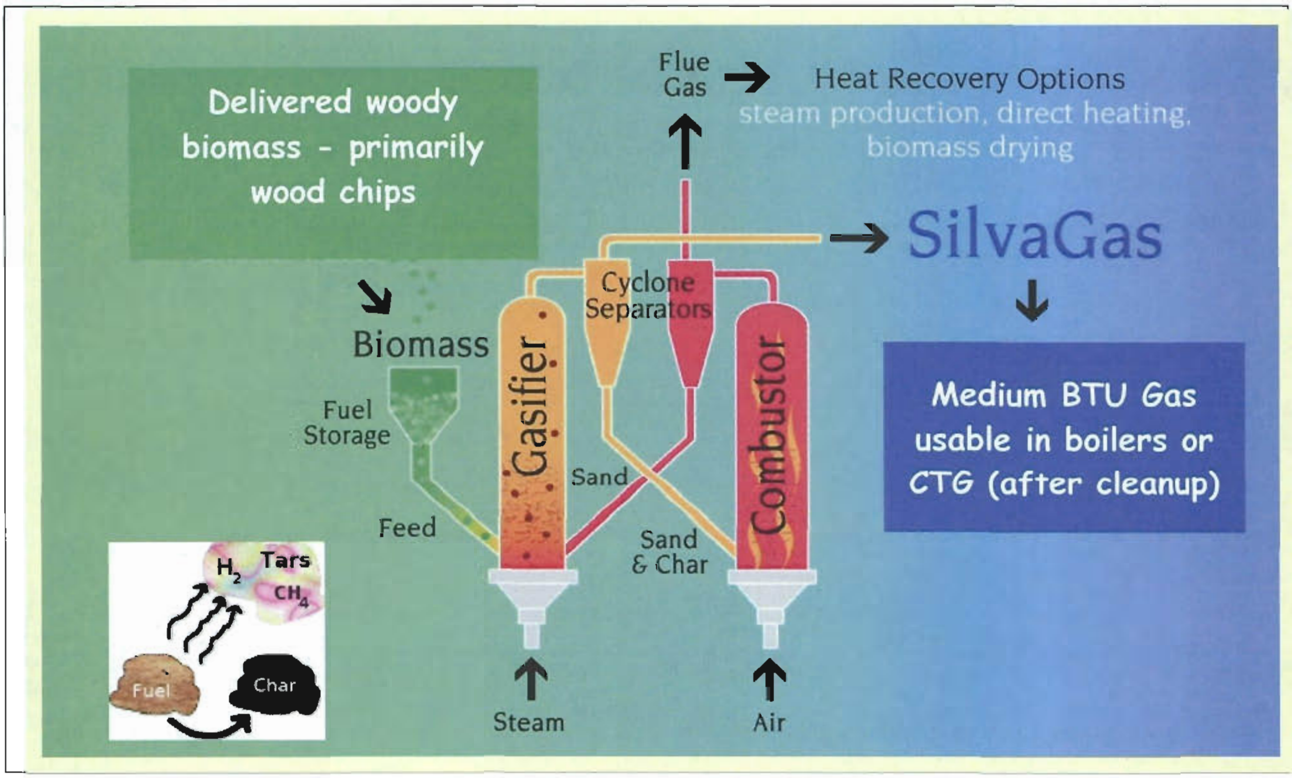

Figure 6. Gasifier/Combustor Section of the SilvaGas Process and Exhaust streams.

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.

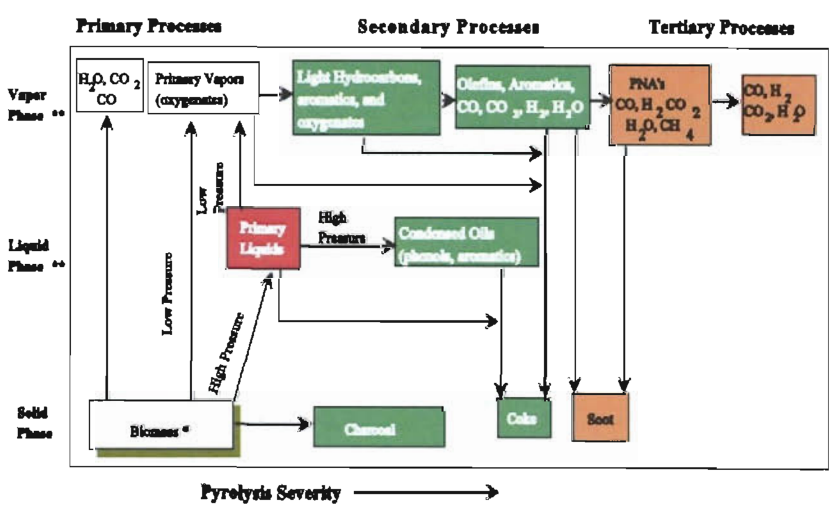

Figure 7. Pyrolysis Pathways.

"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. <u>(EU 005) Cooling Towers</u>

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. <u>(EU 006) Auxiliary Boiler</u>

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. <u>(EU 007) Emergency Generator</u>

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. <u>(EU 008) Emergency Firewater Pump</u>

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.

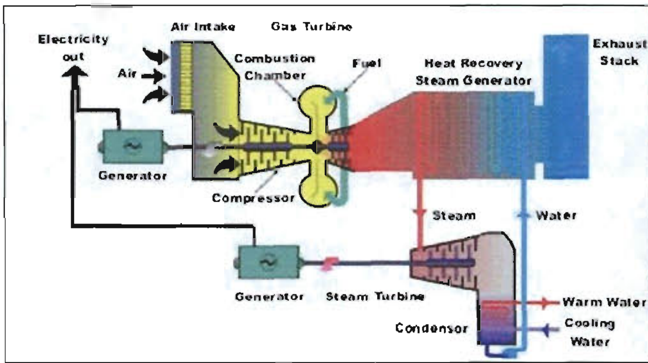

Figure 8. How a Combined Cycle Works. **Figure 9. Picture of a SOLAR T-130 CTG**

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 °F) 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.

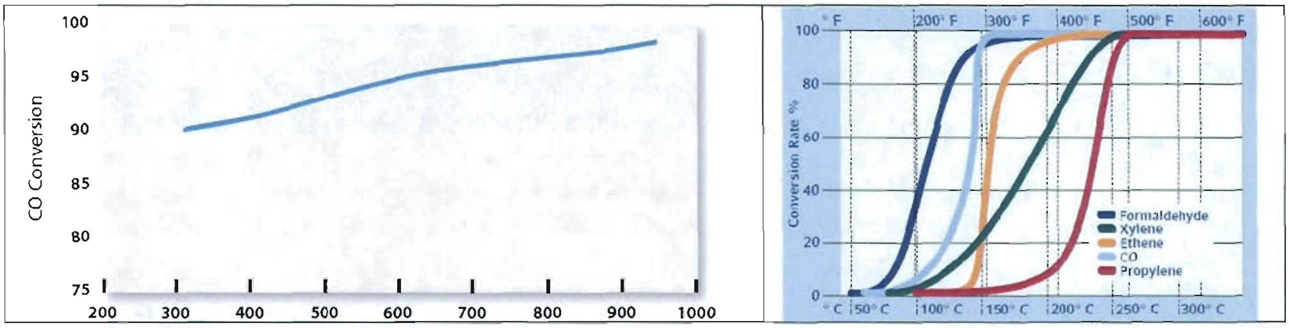

Figure 10. Ox-cat Performance in CO, CH_2O and certain VOC and vs. Temperature (°F and °C)

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.

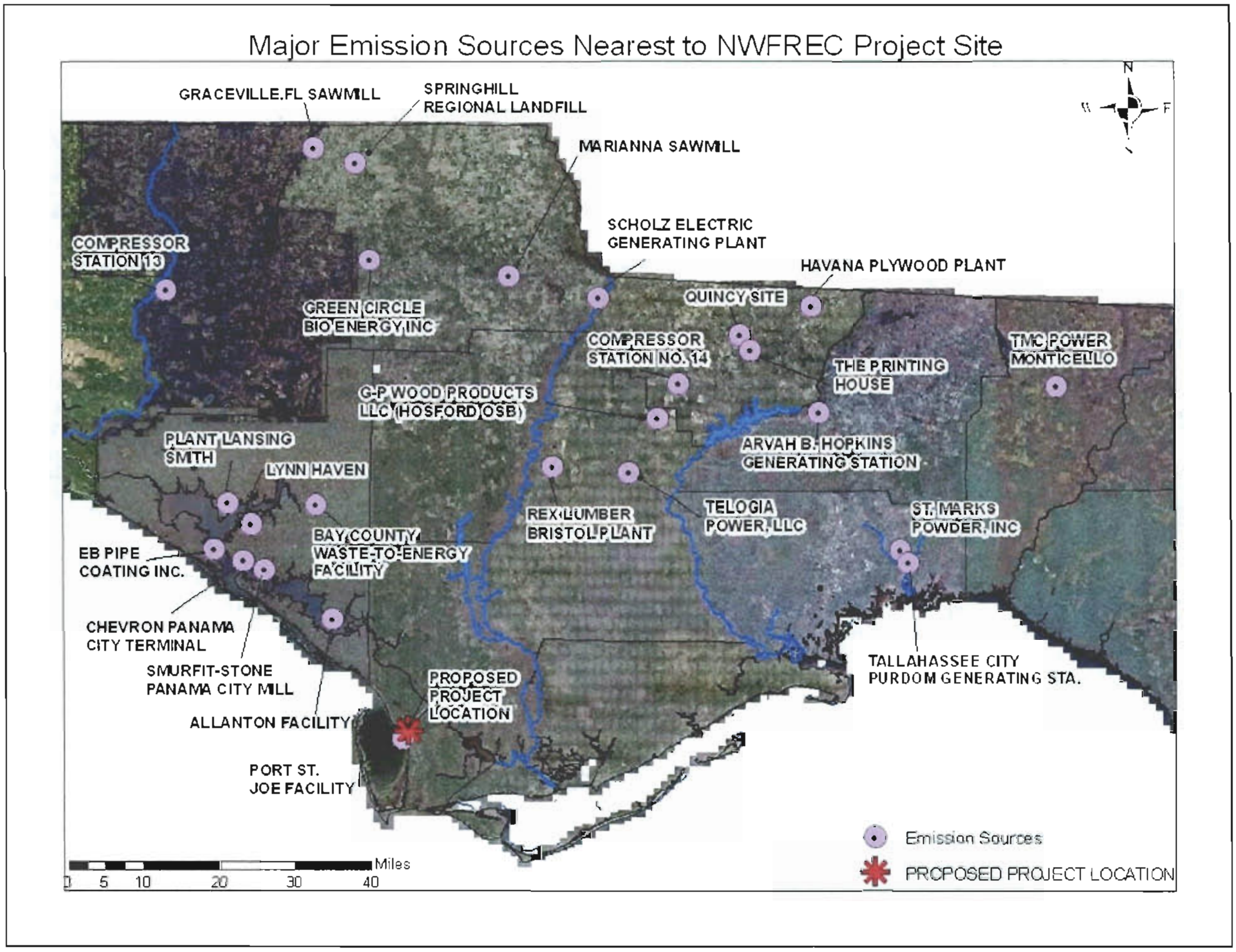

Figure 11. Largest Emission Sources Nearest to Project Site

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.

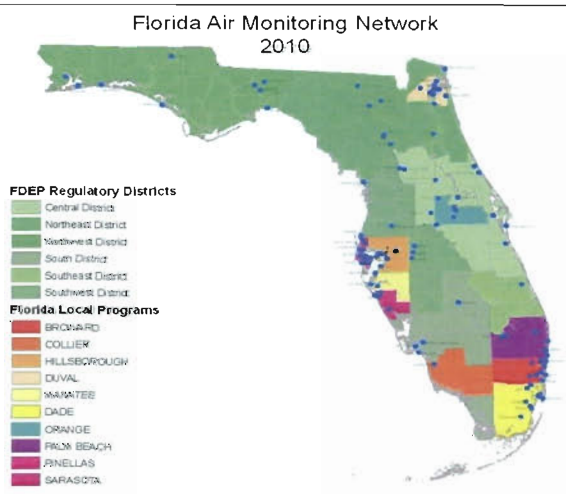

Figure 12. Statewide Monitoring Network. **Figure 13. Stations nearest to the NWFREC Site.**

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	µg/m³
		Annual [c]	2008	22	50	µg/m³
$PM_{2.5}$	Panama City (A0051004)	24-hour [d]	2007-2009	20	35	µg/m³
		Annual [e]	2007-2009	10	15	µg/m³
SO_2	White Springs (B0470015)	1-hour [i]	2008-2010	23	75	ppb
		3-hour [f]	2010	47	1300	µg/m³
		24-hour [f]	2010	8	260	µg/m³
		Annual [c]	2010	3	60	µg/m³
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 (µg/m³); 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.

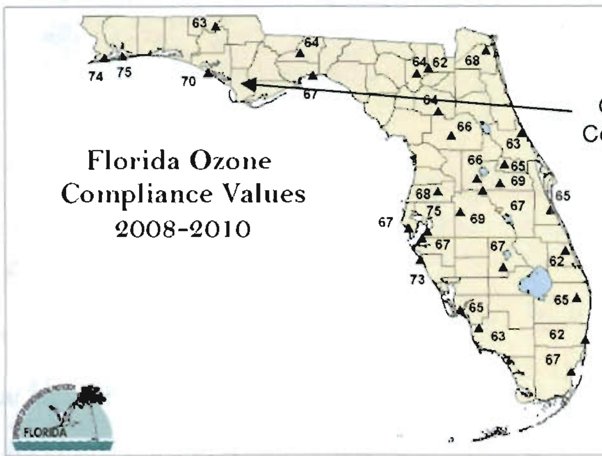

Figure 14. Florida Ozone Compliance Values.

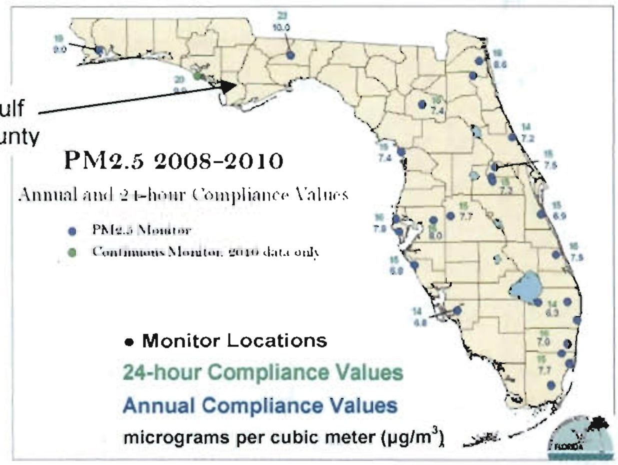

Figure 15. Florida $PM_{2.5}$ Compliance Values.

$PM_{2.5}$ 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.

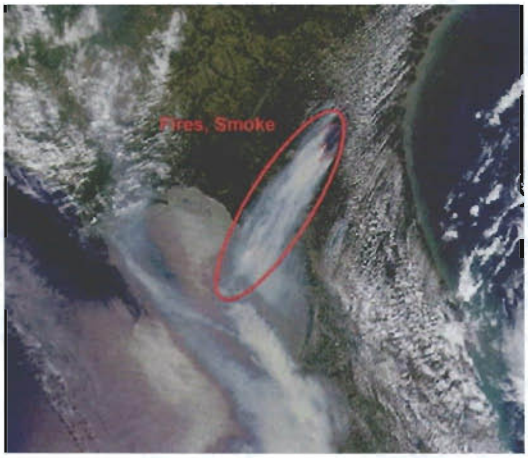

Figure 17. May 11, 2007 Satellite Image.

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.

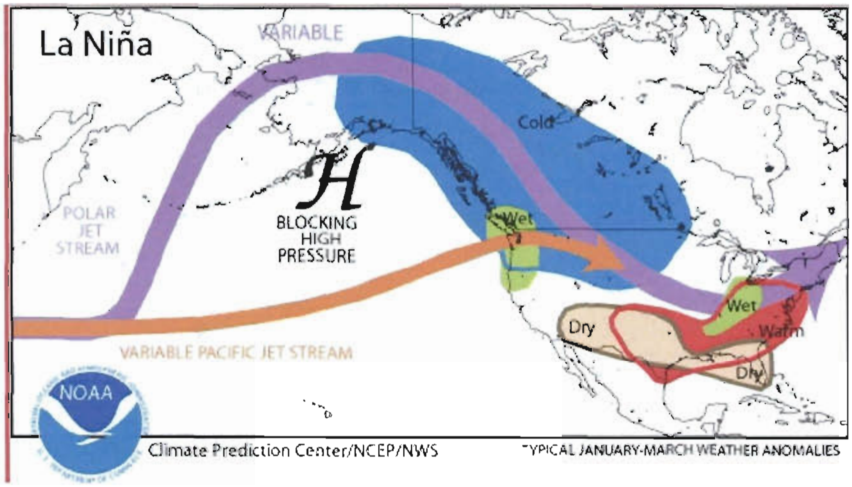

Figure 18. Typical Winter Weather Patterns during a La Niña Episode.

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.

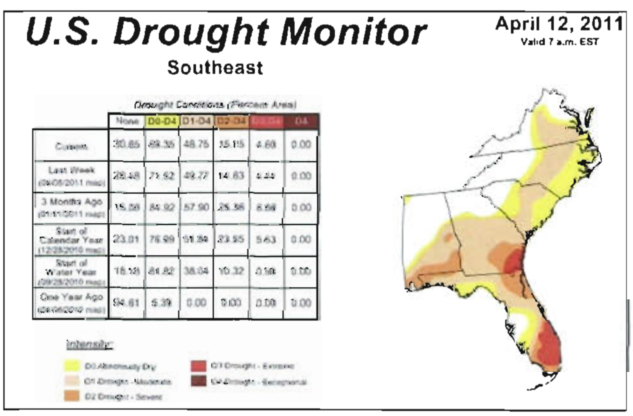

Figure 19. U.S. Drought Monitor as of 4/12/2011. Figure 20. March 25, 2011 Satellite Image.

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:

Melody Lovin, melody.lovin@dep.state.fl.us - Meteorology and Ambient Air Quality

David Read, david.read@dep.state.fl.us - Application Review and Draft Permit Preparation

Alvaro Linero, P.E., alvaro.linero@dep.state.fl.us - Technical Review

They may also be contacted at: 1-850-717-9000

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.

CONTENTS

NSPS AND NESHAP SUBPARTS A – GENERAL PROVISIONS

The provisions of these Subparts may be provided in full upon request. The owner or operator shall comply with all applicable provisions of 40 CFR 60, Subpart A and 40 CFR 63, Subpart A, which is available at the following links:

40 CFR 60, Subpart A

40 CFR 63, Subpart A

NSPS - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NESHAP - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a National Emission Standards for Hazardous Air Pollutants of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibited Activities and Circumvention.

§ 63.5 Preconstruction Review and Notification Requirements.

§ 63.6 Compliance with Standards and Maintenance Requirements.

§ 63.7 Performance Testing Requirements.

§ 63.8 Monitoring Requirements.

§ 63.9 Notification Requirements.

§ 63.10 Recordkeeping and Reporting Requirements.

§ 63.11 Control Device Requirements.

§ 63.12 State Authority and Delegations.

§ 63.13 Addresses of State Air Pollution Control Agencies and EPA Regional Offices.

§ 63.14 Incorporation by Reference.

§ 63.15 Availability of Information and Confidentiality.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

ASTM STANDARD D6751-09 FOR BIODIESEL

ASTM standard for biodiesel is defined as the mono alkyl esters of long chain fatty acids derived from vegetable oils or animal fats, for use in compression-ignition (diesel) engines. This specification is for pure (100%) biodiesel prior to use or blending with diesel fuel.

Standards for Biodiesel	ASTM D-6751	IS 15607 : 2005
Density	Not Mentioned	860 - 900 Kg / m^3
Ester Content	Not Mentioned	96.5 %
Flash point (closed cup)	130°C min. (150°C average)	120°C
Water and sediment	0.050% by vol., max.	500 mg / Kg, max.
Kinematic viscosity at 40°C	1.9-6.0 mm^2/s	2.5-6.0 mm^2/s
Oxidation Stability	Not Mentioned	6 hours min, at 110°C
Ramsbottom carbon residue, % mass	0.10	
Sulfated ash	0.020% by mass, max.	
Sulfur	0.0015% by mass, max*.	50 mg / Kg max
Copper strip corrosion 3 hrs. 50°C	No. 3 max	Class 1
Cetane	47 min.	51 min.
Carbon residue	0.050% by mass, max.	
Acid number, mg KOH/g	0.80 max.	0.50 max.
Methanol or Ethanol	Not Mentioned	0.2 % m/m, max
Free glycerin	0.020 % mass	0.020 % mass
Total glycerine (free glycerine and unconverted glycerides combined)	0.24% by mass, max.	0.25% by mass, max.
Group I Metal (Na+K)	5 mg/Kg, max	5 mg/Kg, max
Group II Metal (Ca+Mg)	Not Mentioned	5 mg/Kg, max
Phosphorus content	0.001 max. % mass	10 mg/Kg, max
Distillation	90% @ 360°C	Not Mentioned

* **<u>S 15 Grade Biodiesel</u>** is required for the NWFREC Project to meet the fuel sulfur requirements of 40 CFR 60, NSPS Subparts IIII.

PRELIMINARY BEST MANAGEMENT PRACTICES (BMP) PLAN FOR MINIMIZATION OF FUGITIVE DUST, PILE MANAGEMENT AND FIRE PREVENTION

The permittee shall comply with this BMP plan and any update hereto.
[Rule 62-4.070, F.A.C. Reasonable Assurance and Rule 62-296.320(4)(c), F.A.C.]

{Permitting Note: The preliminary BMP plan will be updated by NWFREC as the engineering of the Biomass Receiving, Handling, Storage and Processing emission unit (EU-001) is finalized. The final BMP plan must be submitted to the Compliance Authority no later than 180 days before the NWFREC facility becomes operational.}

Measures to Minimize Fugitive Emissions	
1)	Conveyor systems and associated drop points shall be enclosed to the extent practicable to minimize exposure to air currents. Enclosed conveyors means that the conveyance belt for the biomass is totally enclosed from above thus preventing wind from causing fugitive dust emissions. However, the bottom of the conveyance belt shall be accessible for maintenance and repairs
2)	Drop points to woody biomass storage areas shall be designed to minimize the overall drop height exposed to air current.
3)	Periodic equipment inspection and maintenance shall be performed to maintain the integrity of conveyor systems and associated drop point enclosures. Appropriate plant records shall be maintained on equipment maintenance performed.
4)	Fuel silos shall be equipped with vent filters.
5)	Plant personnel shall conduct daily inspections of the conveyor systems and associated drop point integrity to identify any equipment abnormalities.
6)	Signs shall be posted identifying warning signs of potential equipment malfunction.
7)	Plant personnel shall be trained on identification of warning signs for potential equipment malfunction.
8)	Procedures shall be established for defining excessive fugitive dust from woody biomass truck unloading operations. Plant personnel shall monitor truck unloading operations and if excessive fugitive dust is detected plant personnel shall implement appropriate fugitive dust minimization techniques. Plant personnel shall be trained on procedures for defining and minimizing excessive dust from the truck unloading operations.
9)	All major roadways at the plant shall be paved.
10)	Mud, dirt, spilled biomass or similar debris shall be removed promptly from the paved roads.
11)	Plant personnel shall be trained on what constitutes excessive dust on paved roads.
12)	Transfer points and fuel bins are equipped with vent filters.
13)	Fuel handling equipment shall be inspected for proper operation and for maintenance requirements.
14)	Plant fuel handling personnel shall implement procedures for monitoring and controlling unplanned fugitive dust emissions, including truck handling and unloading, and dirt or spilled biomass fuel on roads.
15)	Plant personnel shall will spray, wash, scrape, or otherwise remove dirt or spilled biomass fuel on plant roads as necessary to reduce fugitive emissions.

Measures for Storage Pile Management
1) A woody biomass storage pile fugitive dust management plan shall be developed and maintained onsite. The plan shall identify warning signs and identify corrective actions for conditions that could result in excessive wind erosion and fugitive dust formation. Plant personnel shall be trained to recognize such warning signs. 2) Operational plans will recognize conditions such as high winds likely to result in wind erosion and excessive fugitive dust and will instruct plant personnel to curtail movement of fuel by mobile equipment under such conditions. 3) Mechanical moving of woody biomass by front end loaders and other supporting equipment shall be minimized on high wind event days. 4) First in first out biomass utilization shall be implemented to minimize objectionable odors. 5) The woody biomass storage areas shall be monitored and if conditions are conducive to wind erosion and fugitive dust formation, procedures from the fugitive dust plan shall be implemented. 6) Mobile equipment will be used to maintain the pile's design shape and to ensure adherence to FIFO in reclaim operations.
Measures to Minimize Spontaneous Combustion
1) A fire management plan (FMP) shall be developed to identify and list the causes and conditions giving rise to spontaneous combustion. 2) Contact local fire marshal to develop fire management plan. The FMP shall be maintained on site. 3) The FMP shall include: a) requirement to train onsite personnel to handle incipient fires and training on the identification of potential fire hazards; and, b) install and maintain equipment for plant personnel to handle incipient fires. The local fire department shall be invited to participate in onsite training. 4) Sufficient inspections of the woody biomass storage areas shall be performed by plant personnel to identify potential fire hazards. Plant personnel shall be trained on identification of potential fire hazards. 5) Signs which identify potential fire hazards shall be posted at the plant. 6) Incoming unprocessed materials shall be stored in areas in accordance with clearance ranges between each storage area as described in the FMP. 7) The stacker reclaimer shall maximize the removal of older material in order to minimize the stacking of newer material on top of older material. 8) Compaction of woody biomass materials in the storage areas shall be minimized. 9) Fuel pile fire protection equipment may be used for minimization of fugitive dust emissions and dust suppression as required. 10) Plant personnel shall conduct daily inspection for fire hazards and monitor the hazards using video surveillance. 11) The FMP shall describe the use of fire-water cannons, mounted on elevated structures, together with mobile equipment to uncover and rapidly extinguish any smoldering materials. 12) The size of the fuel storage pile will not exceed the design value – this is a primary control measure, based upon the limited on-site fuel storage of about 2 weeks' worth of fuel. Specifically, the stacker will build a pile in zones up to a maximum of 60 feet high (an average of 40 feet high) and the reclaimer will start with the first zone built and reclaim the pile down to within two inches of grade.
Measures for the Control of Permitted Feedstock
Woody biomass is characterized by cellulose, hemicellulose, lignin and mineral content. The biomass for this project is limited to clean woody biomass meaning trees and woody plants, including limbs, tops, trunks, needles, leaves, stalks and other woody parts, grown in a forest, woodland, rangeland environment, tree farm or agricultural crop farm. The term also includes the residues and rejects from the physical (non-chemical) processing of such woody biomass.

According to NWFREC, the feedstock will consist of woody biomass that will be processed at a remote fuel preparation area (or areas) where it will be sorted, screened and chipped to size. The woody biomass feedstock will be delivered via truck to the site at a rate of approximately 65 trucks per day.

NWFREC has identified the following available woody biomass feedstock types for their facility: saw dust; hogged fuel; processed butt cuts, and fuel crop.

Saw Dust is defined as a by-product of forest and forest product operations.

Hogged Fuel is material that comprises land clearing debris that has either been pre-processed, run through a tub grinder, or a horizontal mill at a specific private forest clearing site.

Butt Cuts are untreated round residues that are either of oversized or undersized non processible materials from post or pole manufacturers.

Fuel Crop is a vegetative product specifically grown for energy use or a waste product of agricultural operations (e.g., corn stover, peanut hulls, etc.).

Yard Waste as defined in as defined in § 60.51b (NSPS Subpart Eb - Standards of Performance for Large Municipal Waste Combustors) is allowable up to a maximum rate of 30 TPD. Yard waste is defines as:

***"Yard waste** means 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. Yard waste does not include construction, renovation, and demolition wastes, which are exempt from the definition of municipal solid waste in this section. Yard waste does not include clean wood, which is exempt from the definition of municipal solid waste in this section."*

The following is required from the permittee:

1) Woody biomass feedstocks shall be obtained from vendors that certify that the woody biomass feed stocks they supply to NWFREC meet the definition of woody biomass specified above. In addition, the vendor must certify that the woody biomass does not contain any of the prohibited items listed in **Item 10,** below.
2) Any such vendor certification shall include, in legible fashion, the name of the vendor's representative making the certification as well as the representative's signature. The permittee shall retain records of the certifications for 5 years.
3) The woody biomass feedstock will be delivered to the NWFREC Plant in vehicles designed to prevent release. Woody biomass feedstock shall be delivered to NWFREC primarily by trucks.
4) The permittee shall inspect each shipment of woody biomass upon receipt for any material not specifically identified in this plan. If the permittee identifies any such material, the material shall be rejected and/or marshaled in specified areas until proper disposal can be arranged. Rejected materials shall be moved off site in a logistically reasonable time period.
5) For each original source of woody biomass feedstock, the permittee shall retain documentation of the original source's procedures to prevent the contamination of the woody biomass with any materials not specifically authorized by this permit. Such documentation shall explicitly identify the procedures used to prevent the introduction of any treated wood or any other prohibited materials into the woody biomass.
6) The permittee shall retain documentation of the off-site material handling facility's procedures for receiving, segregating and loading the woody biomass from the original sources. In addition, the permittee shall retain documentation of the quality assurance procedures in place at the off-site handling facility to ensure the woody biomass is not contaminated with any materials not specifically authorized by this permit. Such documentation shall explicitly identify the procedures used to prevent the introduction of any treated wood or any other prohibited materials into the woody biomass.
7) For each shipment of woody biomass, the permittee shall record the date received, the original source and the material description of the woody biomass and the quantity received, and the name, in a legible fashion,

and signature of the individual(s) responsible for performing the visible inspection in **Item 8**, below.

8) The permittee shall inspect each shipment of woody biomass upon receipt and during unloading for any material not specifically authorized by this permit. If the permittee identifies any such material, the material must be removed from the shipment and the material vendor notified. The rejected material must be disposed of following all applicable Department regulations. The permittee shall maintain a record of rejected materials, the amount of material rejected and the reason(s) for rejection.
9) The permittee shall maintain records of rejected shipments and disposition thereof. Such records shall be made available to the Department upon request.
10) The following items are not considered woody biomass and are expressly prohibited:
    a) those materials that are prohibited by state or federal law;
    b) plastics;
    c) woody biomass that has been chemically treated or processed;
    d) municipal solid waste (other than yard waste);
    e) paper;
    f) treated wood such as CCA or creosote;
    g) painted wood; and
    h) wood wastes from landfills.

Measures to Minimize Ash Fugitive Dust

The ash will be collected in a series of primary and secondary cyclones as the flue gas exits the gasifier combustor. It will drop through the cyclones into an ash hopper and will be quenched with water to both lower the temperature for handling and control (PM) dust emissions. When the hopper is full, the ash will exit the hopper from the bottom into a truck and then covered to leave the site for disposal. Tars that are recovered shall be contained within a closed loop system and recycled to the char combustor.

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the NWFREC facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: 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 2 hours in any 24-hour period unless specifically authorized by the Department for longer duration. Pursuant to Rule 62-210.700(5), F.A.C., the permit subsection may specify more or less stringent requirements for periods of excess emissions. Rule 62-210-700(Excess Emissions), F.A.C., cannot vary or supersede any federal NSPS or NESHAP provision. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(Definitions), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions. During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

RECORDS AND REPORTS

10. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]
11. Emissions Computation and Reporting
    a. *Applicability.* This rule sets forth required methodologies to be used by the owner or operator of a facility for computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for computing emissions for purposes of the reporting requirements of subsection 62-210.370(3) and paragraph 62-212.300(1)(e), F.A.C., or of any permit condition that requires emissions be computed in accordance with this rule. This rule is not intended to establish methodologies for determining compliance with the emission limitations of any air permit.
    b. *Computation of Emissions.* For any of the purposes set forth in subsection 62-210.370(1), F.A.C., the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.
        (1) Basic Approach. The owner or operator shall employ, on a pollutant-specific basis, the most accurate of the approaches set forth below to compute the emissions of a pollutant from an emissions unit; provided, however, that nothing in this rule shall be construed to require installation and operation of any continuous emissions monitoring system (CEMS), continuous parameter monitoring system (CPMS), or predictive emissions monitoring system (PEMS) not otherwise required by rule or permit, nor shall anything in this rule be construed to require performance of any stack testing not otherwise required by rule or permit.
            (a) If the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute the emissions of the pollutant, unless the owner or operator demonstrates to the department that an alternative approach is more accurate because the CEMS represents still-emerging technology.
            (b) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C, but emissions of the pollutant can be computed pursuant to the mass balance methodology of paragraph 62-210.370(2)(c), F.A.C., the owner or operator shall use such methodology, unless the owner or operator demonstrates to the department that an alternative approach is more accurate.
            (c) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., and emissions cannot be computed pursuant to the mass balance methodology, the owner or operator shall use an emission factor meeting the requirements of paragraph 62-210.370(2)(d), F.A.C., unless the owner or operator demonstrates to the department that an alternative approach is more accurate.
        (2) Continuous Emissions Monitoring System (CEMS).
            (a) An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:
                1) The CEMS complies with the applicable certification and quality assurance requirements of 40 CFR Part 60, Appendices B and F, or, for an acid rain unit, the certification and quality assurance requirements of 40 CFR Part 75, all adopted by reference at Rule 62-204.800, F.A.C.; or

2) The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.

(b) Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:

1) A calibrated flowmeter that records data on a continuous basis, if available; or

2) The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

(c) The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.

(3) Mass Balance Calculations.

(a) An owner or operator may use mass balance calculations to compute emissions of a pollutant for purposes of this rule provided the owner or operator:

1) Demonstrates a means of validating the content of the pollutant that is contained in or created by all materials or fuels used in or at the emissions unit; and

2) Assumes that the emissions unit emits all of the pollutant that is contained in or created by any material or fuel used in or at the emissions unit if it cannot otherwise be accounted for in the process or in the capture and destruction of the pollutant by the unit's air pollution control equipment.

(b) Where the vendor of a raw material or fuel which is used in or at the emissions unit publishes a range of pollutant content from such material or fuel, the owner or operator shall use the highest value of the range to compute the emissions, unless the owner or operator demonstrates using site-specific data that another content within the range is more accurate.

(c) In the case of an emissions unit using coatings or solvents, the owner or operator shall document, through purchase receipts, records and sales receipts, the beginning and ending VOC inventories, the amount of VOC purchased during the computational period, and the amount of VOC disposed of in the liquid phase during such period.

(4) Emission Factors.

a. An owner or operator may use an emission factor to compute emissions of a pollutant for purposes of this rule provided the emission factor is based on site-specific data such as stack test data, where available, unless the owner or operator demonstrates to the department that an alternative emission factor is more accurate. An owner or operator using site-specific data to derive an emission factor, or set of factors, shall meet the following requirements.

1) If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid stack tests conducted during at least a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

2) Multiple emission factors shall be used as necessary to account for variations in emission rate associated with variations in the emissions unit's operating rate or operating conditions during the period over which emissions are computed.

3) The owner or operator shall compute emissions by multiplying the appropriate emission factor by the appropriate input, output or gas volume value for the period over which the emissions are computed. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.

b. If site-specific data are not available to derive an emission factor, the owner or operator may use a published emission factor directly applicable to the process for which emissions are computed. If no directly-applicable emission factor is available, the owner or operator may use a factor based on a similar, but different, process.

(5) Accounting for Emissions During Periods of Missing Data from CEMS, PEMS, or CPMS. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of missing data from CEMS, PEMS, or CPMS using other site-specific data to generate a reasonable estimate of such emissions.

(6) Accounting for Emissions During Periods of Startup and Shutdown. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.

(7) Fugitive Emissions. In computing the emissions of a pollutant from a facility or emissions unit, the owner or operator shall account for the fugitive emissions of the pollutant, to the extent quantifiable, associated with such facility or emissions unit.

(8) Recordkeeping. The owner or operator shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the department for any regulatory purpose.

c. *Annual Operating Report for Air Pollutant Emitting Facility*

(1) The Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for the following facilities:

(a) All Title V sources.

(b) All synthetic non-Title V sources.

(c) All facilities with the potential to emit ten (10) tons per year or more of volatile organic compounds or twenty-five (25) tons per year or more of nitrogen oxides and located in an ozone nonattainment area or ozone air quality maintenance area.

(d) All facilities for which an annual operating report is required by rule or permit.

(2) Notwithstanding paragraph 62-210.370(3)(a), F.A.C., no annual operating report shall be required for any facility operating under an air general permit.

(3) The annual operating report shall be submitted to the appropriate Department of Environmental Protection (DEP) division, district or DEP-approved local air pollution control program office by April 1 of the following year.

(4) Beginning with 2007 annual emissions, emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C., for purposes of the annual operating report.

[RULE 62-210.370, F.A.C.]

CEMS OPERATION PLAN

1. CEMS Operation Plan: The owner or operator shall create and implement a facility-wide plan for the proper installation, calibration, maintenance and operation of each CEMS required by this permit. The owner or operator shall submit the CEMS Operation Plan to the Bureau of Air Monitoring and Mobile Sources for approval at least 60 days prior to CEMS installation. The CEMS Operation Plan shall become effective 60 days after submittal or upon its approval. If the CEMS Operation Plan is not approved, the owner or operator shall submit a new or revised plan for approval.

   {Permitting Note: The Department maintains both guidelines for developing a CEMS Operation Plan and example language that can be used as the basis for the facility-wide plan required by this permit. Contact the Emissions Monitoring Section of the Bureau of Air Monitoring and Mobile Sources at (850)488-0114.}

INSTALLATION, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

2. Timelines:

   a. *New and Existing Emission Units.* For new emission units, the owner or operator shall install each CEMS required by this permit prior to initial startup of the unit. The owner or operator shall conduct the appropriate performance specification for each CEMS within 90 operating days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup.

3. Installation: All CEMS shall be installed such that representative measurements of emissions or process parameters from the facility are obtained. The owner or operator shall locate the CEMS by following the procedures contained in the applicable performance specification of 40 CFR part 60, Appendix B.

4. Span Values and Dual Range Monitors: The owner or operator shall set appropriate span values for the CEMS. The owner or operator shall install dual range monitors if required by and in accordance with the CEMS Operation Plan.

5. Continuous Flow Monitor: For compliance with mass emission rate standards, the owner or operator shall install a continuous flow monitor to determine the stack exhaust flow rate. The flow monitor shall be certified pursuant to 40 CFR part 60, Appendix B, Performance Specification 6.

6. Diluent Monitor: If it is necessary to correct the CEMS output to the oxygen concentrations specified in this permit's emission standards, the owner or operator shall either install an oxygen monitor or install a CO_2 monitor and use an appropriate F-Factor computational approach.

7. Moisture Correction: If necessary, the owner or operator shall determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture).

   {Permitting Note: The CEMS Operation Plan will contain additional CEMS-specific details and procedures for installation.}

8. Performance Specifications: The owner or operator shall evaluate the acceptability of each CEMS by conducting the appropriate performance specification, as follows. CEMS determined to be unacceptable shall not be considered installed for purposes of meeting the timelines of this permit.

   a. *CO Monitors:* For CO monitors, the owner or operator shall conduct Performance Specification 4 or 4A of 40 CFR part 60, Appendix B

   b. *NO_X Monitor:* For a NO_X monitor, the owner or operator shall conduct Performance Specification 2 of 40 CFR part 60, Appendix B.

c. COMS: In accordance with 40 CFR 60.48b(a) the permittee shall install, calibrate, operate and maintain a continuous opacity monitor (COM) to continuously monitor and record opacity from the char combustor. The COMS shall be certified pursuant to 40 CFR 60 Appendix B, Performance Specification 1.

9. Quality Assurance: The owner or operator shall follow the quality assurance procedures of 40 CFR part 60, Appendix F.

   a. *CO Monitors:* The required relative accuracy test audit (RATA) tests shall be performed using EPA Method 10 in Appendix A of 40 CFR part 60 and shall be based on a continuous sampling train.

   b. *NO_X Monitors:* The required RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR part 60. NO_X shall be expressed "as NO_2."

10. Substituting RATA Tests for Compliance Tests: Data collected during CEMS quality assurance RATA tests can substitute for annual stack tests, and vice versa, at the option of the owner or operator, provided the owner or operator indicates this intent in the submitted test protocol and follows the procedures outlined in the CEMS Operation Plan.

CALCULATION APPROACH

11. CEMS Used for Compliance: Once adherence to the applicable performance specification for each CEMS is demonstrated, the owner or operator shall use the CEMS to demonstrate compliance with the applicable emission standards as specified by this permit.

12. CEMS Data: Each CEMS shall monitor and record emissions during all periods of operation and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments and span adjustments, and except for allowable data exclusions as per Condition 19 of this appendix.

13. Operating Hours and Operating Days: For purposes of this appendix, the following definitions shall apply. An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Unless otherwise specified by this permit, any day with at least one operating hour for an emissions unit is an operating day for that emission unit.

14. Valid Hourly Averages: Each CEMS shall be designed and operated to sample, analyze and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

   a. Hours that are not operating hours are not valid hours.

   b. For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

15. Calculation Approaches: The owner or operator shall implement the calculation approach specified by this permit for each CEMS, as follows:

   a. *Rolling 30-day Average*: Compliance shall be determined after each operating day by calculating the arithmetic average of all the valid hourly averages from that operating day and the prior 29 operating days.

b. *Rolling12-month average, rolled monthly:* Compliance shall be determined after each operating month by calculating the arithmetic average of all the valid hourly averages from that operating month and the prior x-1 operating months.

MONITOR AVAILABILITY

16. Monitor Availability: The quarterly excess emissions report shall identify monitor availability for each quarter in which the unit operated. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter in which the unit operated for more than 760 hours. In the event the applicable availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving the required availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

EXCESS EMISSIONS

17. Definitions:

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

    b. *Shutdown* means the cessation of the operation of an emissions unit for any purpose.

    c. *Malfunction* means any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

18. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.

19. Data Exclusion Procedures for SIP Compliance: As per the procedures in this condition, limited amounts of CEMS emissions data may be excluded from the corresponding compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. The data exclusion procedures of this condition apply only to SIP-based emission limits.

    a. *Excess Emissions.* Data in excess of the applicable emission standard may be excluded from compliance calculations if the data are collected during periods of permitted excess emissions (for example, during startup, shutdown or malfunction). The maximum duration of excluded data is 2 hours in any 24-hour period, unless some other duration is specified by this permit. For the CEMS on the HRSG stacks at the NWFREC facility, excess emissions of NO_X and CO during periods of startup, shutdown and malfunction cannot be excluded. This is to ensure that the 250 TPY emission limits for these pollutants are not exceeded which if they were would trigger PSD regulations.

    b. *Limited Data Exclusion.* If the compliance calculation using all valid CEMS emission data, as defined in Condition 12 of this appendix, indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

    c. *Event Driven Exclusion.* The underlying event (for example, the startup, shutdown or malfunction event) must precede the data exclusion. If there is no underlying event, then no data may be excluded. Only data collected during the event may be excluded.

d. *Reporting Excluded Data.* The data exclusion procedures of this condition are not necessarily the same procedures used for excess emissions as defined by federal rules. Quarterly or semi-annual reports required by this permit shall indicate not only the duration of data excluded from SIP compliance calculations but also the number of excess emissions as defined by federal rules.

20. Notification Requirements: The owner or operator shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate noncompliance for a given averaging period. Within one working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data. For malfunctions, notification is sufficient for the owner or operator to exclude CEMS data.

ANNUAL EMISSIONS

21. CEMS Used for Calculating Annual Emissions: All valid data, as defined in Condition 12 of this appendix, shall be used when calculating annual emissions.

    a. Annual emissions shall include data collected during startup, shutdown and malfunction periods.

    b. Annual emissions shall include data collected during periods when the emission unit is not operating but emissions are being generated (for example, when firing fuel to warm up a process for some period of time prior to the emission unit's startup).

    c. Annual emissions shall not include data from periods of time where the monitor was functioning properly but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit or RAA. These periods of time shall be considered missing data for purposes of calculating annual emissions.

    d. Annual emissions shall not include data from periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered missing data for purposes of calculating annual emissions.

22. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hour block average. For each hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the owner or operator shall account for emissions during that hour using site-specific data to generate a reasonable estimate of the 1-hour block average.

23. Emissions Calculation: Hourly emissions shall be calculated for each hour as the product of the 1-hour block average and the duration of pollutant emissions during that hour. Annual emissions shall be calculated as the sum of all hourly emissions occurring during the year.

CITATION FORMATS

The following illustrate the formats used in the permit to identify applicable requirements from permits and regulations.

Old Permit Numbers

Example: Permit No. AC50-123456 or Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located

"2222" represents the specific facility ID number for that county

"001"identifies the specific permit project number

"AC" identifies the permit as an air construction permit

"AF" identifies the permit as a minor source federally enforceable state operation permit

"AO" identifies the permit as a minor source air operation permit

"AV" identifies the permit as a major Title V air operation permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the preconstruction review requirements of the Prevention of Significant Deterioration of Air Quality

"FL" means that the permit was issued by the State of Florida

"317" identifies the specific permit project number

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

GLOSSARY OF COMMON TERMS

° F: degrees Fahrenheit

acfm: actual cubic feet per minute

ARMS: Air Resource Management System (Department's database)

BACT: best available control technology

Btu: British thermal units

CAM: compliance assurance monitoring

CEMS: continuous emissions monitoring system

cfm: cubic feet per minute

CFR: Code of Federal Regulations

CO: carbon monoxide

COMS: continuous opacity monitoring system

DEP: Department of Environmental Protection

Department: Department of Environmental Protection

dscfm: dry standard cubic feet per minute

EPA: Environmental Protection Agency

ESP: electrostatic precipitator (control system for reducing particulate matter)

EU: emissions unit

F.A.C.: Florida Administrative Code

F.D.: forced draft

F.S.: Florida Statutes

FGR: flue gas recirculation

F: fluoride

ft^2: square feet

ft^3: cubic feet

gpm: gallons per minute

gr: grains

HAP: hazardous air pollutant

Hg: mercury

I.D.: induced draft

ID: identification

kPa: kilopascals

lb: pound

MACT: maximum achievable technology

MMBtu: million British thermal units

MSDS: material safety data sheets

MW: megawatt

NESHAP: National Emissions Standards for Hazardous Air Pollutants

NO_X: nitrogen oxides

NSPS: New Source Performance Standards

O&M: operation and maintenance

O_2: oxygen

Pb: lead

PM: particulate matter

PM_{10}: particulate matter with a mean aerodynamic diameter of 10 microns or less

PSD: prevention of signifi9cant deterioration

psi: pounds per square inch

PTE: potential to emit

RACT: reasonably available control technology

RATA: relative accuracy test audit

SAM: sulfuric acid mist

scf: standard cubic feet

scfm: standard cubic feet per minute

SIC: standard industrial classification code

SNCR: selective non-catalytic reduction (control system used for reducing emissions of nitrogen oxides)

SO_2: sulfur dioxide

TPH: tons per hour

TPY: tons per year

UTM: Universal Transverse Mercator coordinate system

VE: visible emissions

VOC: volatile organic compounds

CITATION FORMATS AND GLOSSARY OF COMMON TERMS

Application

NWFRC: Northwest Florida Renewable Energy Center

BIGCC: biomass-fed integrated gasification combined cycle

BPG: biomass product gas

HRSG: heat recovery steam generators

CT: combustion turbine-electrical generators

DB: duct burners

CEMS: continuous emissions monitoring system

COMS: continuous opacity monitoring system

Unless otherwise specified in the permit, the following testing requirements apply to all emissions units at the facility.

COMPLIANCE TESTING REQUIREMENTS

1. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]

2. Applicable Test Procedures - Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

    a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

    b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

    c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

    [Rule 62-297.310(4), F.A.C.]

3. Determination of Process Variables

    a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

    b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

    [Rule 62-297.310(5), F.A.C.]

4. Frequency of Compliance Tests: The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

    a. *General Compliance Testing.*

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.
2. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision.

   In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

   (a) Did not operate; or

   (b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,
3. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for visible emissions, if there is an applicable standard.
4. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

b. *Special Compliance Tests*. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

[Rule 62-297.310(7), F.A.C.]

RECORDS AND REPORTS

5. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report shall provide the following information.

   a. The type, location, and designation of the emissions unit tested.

   b. The facility at which the emissions unit is located.

   c. The owner or operator of the emissions unit.

   d. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.

   e. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

   f. The date, starting time and end time of the observation.

g. The test procedures used.

h. The names of individuals who furnished the process variable data, conducted the test, and prepared the report.

i. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.

j. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

{Permitting Note: This is a modified version of NSPS, Subpart Db that retains the information applicable to the NWFREC project. Parts that are critical to the NWFREC project are provided in "Bold" text. To access the full version of NSPS, Subpart Db, follow the link at the end of this appendix.}

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Source: 72 FR 32742, June 13, 2007, unless otherwise noted.

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 million British thermal units per hour (MMBtu/hr).

(b) through (f) are not applicable (NA).

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

(h) through (k) are NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Gaseous fuel means any fuel that is a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 70,000 Btu/hr-ft^3.

ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Low heat release rate means a heat release rate of 70,000 Btu/hr-ft^3 or less.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (lb/mmBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical SO_2 emissions (lb/mmBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion emission control systems.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Very low sulfur oil means for units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 0.32 lb/mmBtu heat input.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.42b Standard for sulfur dioxide (SO_2).

(a) through (d) are NA.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) NA.

(g) Except as provided in paragraph (i) of this section and §60.45b(a), the SO_2 emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) through (j) are NA.

(k)

(1) NA due to election by applicant to comply with (k)(2) below.

(2) Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 0.32 lb/mmBtu heat input or less are exempt from the SO_2 emissions limit in paragraph (k)(1) of this section.

(3) NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.43b Standard for particulate matter (PM).

(a) through (d) are NA.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) **On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that can combust coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.** Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/mmBtu or less are exempt from the opacity standard specified in this paragraph.

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

(h)

(1) **Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 0.030 lb/mmBtu heat input,**

(2) NA due to election by applicant to comply with (h)(1) above.

(3) through (6) are NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.44b Standard for nitrogen oxides (NO_X).

(a) NA except for subsequent reference to the following table:

Fuel/steam generating unit type	**Nitrogen oxide emission limits (expressed as NO_2) (lb/mmBtu heat input)**
(1) Natural gas and distillate oil:	
(i) Low heat release rate	0.10
(ii) High heat release rate	0.20

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of a limit determined by the use of the following formula:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n= NO_X emission limit (expressed as NO_2), lb/mmBtu;

EL_{go}= Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, lb/mmBtu;

H_{go}= Heat input from combustion of natural gas or distillate oil, mmBtu;

(c) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) **On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of 0.30 lb/mmBtu heat input** unless the affected facility has an annual capacity factor for natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas.

(e) through (g) are NA.

(h) For purposes of paragraph (i) of this section, the NO_X standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) and (k) are NA.

(l) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the following limits:

(1) If the affected facility combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels: A limit of 0.20 lb/mmBtu heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

E_n= NO_X emission limit, (lb/mmBtu);

H_{go}= 30-day heat input from combustion of natural gas or distillate oil; and

H_r= 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 2.1 lb/MWh gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i) of subpart Da of this part, and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of this part.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) NA.

(b) In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) Through (j) NA.

(k) The owner or operator of an affected facility seeking to demonstrate compliance in §§60.42b(d)(4), 60.42b(j), 60.42b(k)(2), and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures in §60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_X emission standards under §60.44b apply at all times.

(b) Compliance with the PM emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_X emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3A or 3B of appendix A–2 of this part is used for gas analysis when applying Method 5 of appendix A–3 of this part or Method 17 of appendix A–6 of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:
  (i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and
  (ii) Method 17 of appendix A–6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F).
  (iii) NA.
(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.
(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).
(5) For determination of PM emissions, the oxygen (O_2) or CO_2sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.
(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:
  (i) The O_2 or CO_2 measurements and PM measurements obtained under this section;
  (ii) The dry basis F factor; and
  (iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.
(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.
(e) To determine compliance with the emission limits for NO_X required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NO_X under §60.48(b).
    (1) For the initial compliance test, NO_X from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_X emission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.
    (2) NA.
    (3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 250 mmBtu/hr and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_X standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.
    (4) Following the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected

facility that has a heat input capacity of 250 mmBtu/hr or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards in §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(5) NA.

(f) through (i) are NA.

(j) NA unless applicant elects to install, calibrate and operate a PM-CEMS.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2 standards in §60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the $SO_2$and either O_2or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2control device. If the owner or operator has installed and certified SO_2 and O_2or CO_2 CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

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

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

(3) The reporting requirements of §60.49b are met. $SO_2$and CO_2(or O_2) data used to meet the requirements of §60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) NA.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO_2 emission rates measured by the CEMS required by paragraph (a) of this section and required under §60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under §60.42(b). Each 1-hour average SO_2 emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to §60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO_2CEMS at the inlet to the SO_2control device is 125 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2control device is 50 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted. Alternatively, SO_2span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required $CO_2$and O_2monitors and for $SO_2$and NO_X monitors with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part.

(ii) For all required $CO_2$and O_2monitors and for $SO_2$and NO_X monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for $SO_2$and NO_X span values less than or equal to 30 ppm; and

(iii) For SO_2, CO_2, and O_2monitoring systems and for NO_X emission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2 (regardless of the SO_2 emission level during the RATA), and for NO_X when the average NO_X emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under §60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in §60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009]

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. [The rest of this paragraph is NA because the applicant will install a COMS.

(1) through (3) are NA because the applicant will install a COMS.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_X standard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_X and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_X emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49b. Data reported to meet the requirements of §60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average NO_X emission rates measured by the continuous NO_X monitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in lb/mmBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a COMS shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_X is determined using one of the following procedures:
(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_X span values shall be determined as follows:

Fuel	Span values for NO_X (ppm)
Natural gas	500
Oil	500
Coal	1,000
Mixtures	500 (x + y) + 1,000z

Where:
x = Fraction of total heat input derived from natural gas;
y = Fraction of total heat input derived from oil; and
z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) through (i) are NA.

(j) NA because applicant will install a COMS.

(k) NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009]

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

(4) NA because the applicant is not using an emerging technology for SO_2 control.

(b) The owner or operator of each affected facility subject to the SO_2, PM, and/or NO_X emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) NA because the applicant will demonstrate NO_X compliance by use of a CEMS

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(2) NA.

(e) NA.

(f) For an affected facility subject to the opacity standard in §60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in §60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) NA because the applicant will use a COMS.

(2) NA because the applicant will use a COMS.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_X standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_X emission rates (expressed as NO_2) (lb/mmBtu heat input) measured or predicted;

(3) The 30-day average NO_X emission rates (lb/mmBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in §60.43b(f) or to the operating parameter monitoring requirements in §60.13(i)(1).

(2) Any affected facility that is subject to the NO_X standard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2 standards under §60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO_2 emission rate (lb/mmBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO_2control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

(3) Each 30-day average percent reduction in SO_2 emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(7) Identification of times when hourly averages have been obtained based on manual sampling methods;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO_2 emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2standards in §60.42(b) for which the minimum amount of data required in §60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:
   (1) The number of hourly averages available for outlet emission rates and inlet emission rates;
   (2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;
   (3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and
   (4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) NA.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:
   (1) Calendar date;
   (2) The number of hours of operation; and
   (3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:
   (1) The annual capacity factor over the previous 12 months;
   (2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and
   (3) If the affected facility meets the criteria described in §60.44b(j), the results of any NO_X emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_X emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:
   (1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in §60.42b(j) or §60.42b(k) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted

to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) through (u) are NA.

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) and (y) are NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009]

Link to 40 CFR 60, Subpart Db

NSPS SUBPART DC - SMALL INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

A 62 mmBtu/hr auxiliary boiler firing natural gas that will be used to produce steam during start up of the STG is regulated under this NSPS. It is designated as Emissions Unit 009. In addition, the 25 mmBtu/hr gasified startup burner and the 17 mmBtu/hr char combustor startup burner are regulated under this NSPS. The startup burner for the gasifier is included in Emission Unit 002, while the startup burner for the char combustor is included in Emission Unit 003. These units are subject only to record keeping and reporting requirements since these combustion units fire only natural gas.

The entire regulation is accessible at the following link:

Link to Subpart Dc

{Note: Only applicable definitions have been included below.}

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (i.e. , the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO2control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO2control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Natural gas means (1) a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835-86, 87, 91, or 97, "Standard Specification for Liquefied Petroleum Gases" (incorporated by reference -- see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

§ 60.42c Standard for sulfur dioxide.

§ 60.43c Standard for particulate matter.

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

§ 60.46c Emission monitoring for sulfur dioxide.

§ 60.47c Emission monitoring for particulate matter.

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.
8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
   a. A description of and cause of non-compliance; and
   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology ( );
    b. Determination of Prevention of Significant Deterioration ( ); and
    c. Compliance with New Source Performance Standards (X).
14. The permittee shall comply with the following:
    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
    c. Records of monitoring information shall include:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

NSPS, SUBPART IIII - STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

A 500 kW or less emergency generator (EU 007) and a 335 hp or less fire pump (EU-008) are proposed for the NWFREC and are subject to the applicable requirements of 40 CFR 60, Subpart IIII--Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The provisions of this Subpart may be provided in full upon request and are also available at the following link:

Link to Subpart IIII

NESHAP SUBPART JJJJJJ: FOR AREA SOURCE INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS

The NWFREC char combustor is regulated as EU 003. This emissions unit shall comply with all applicable requirements of 40 CFR 63, Subpart JJJJJJ: National Emission Standards for Hazardous Air Pollutants – For Area Source Industrial, Commercial, and Institutional Boilers.

The full provisions may be provided in full upon request and are also available beginning at the below web link below:

Link to Subpart JJJJJJ

Table 1 is a listing of the emissions limits from Subpart JJJJJJ that apply to the NWFREC project.

Table 1. Emission Limits from NESHAP 40 CFR 63, Subpart JJJJJJ.

Boiler Type	Heat Input (mmBtu/hr)	PM Limit	CO Limit
New Biomass Boiler	≥ 30	0.03 lb/mmBtu	100 ppmvd at 7% oxygen

The NWFREC combustion turbines generators (CTG) are regulated as Emissions Units (EU) 011, 012 and 011 for the Solar Model T-130 CTG option and EU 011 for the General Electric (GE) MS6001B CTG option. The CTG are part of the combined cycle unit. These emissions units shall comply with all applicable requirements of 40 CFR 60, Subpart KKKK-- Standards of Performance for Stationary Combustion Turbines.

The full provisions may be provided in full upon request and are also available beginning at the web link below:

Link to Subpart KKKK

Table 1 is a listing of the NO_X limits from Subpart KKKK that apply to the NWFREC project.

Table 1. NO_X Emission Limits for New Stationary Combustion Turbines [1]. Subpart KKKK of Part 60.

CT Type	CT Heat Input at Peak Load (HHV) [2]	NO_X Emission Standard [3]
New turbine firing natural gas	> 50 MMBtu/ hour and ≤ 850 MMBtu/hour	25 ppmvd at 15% oxygen
New turbine firing fuels other than natural gas	> 50 MMBtu/hour and ≤ 850 MMBtu/hour	74 Ppmvd [2] at 15% oxygen

1. Only the portion of the table that includes the NO_X requirements applicable to the NWFREC project.
2. Heat input on higher heating value (HHV) basis.
3. Permittee proposes a NO_X emission limit of 8.99 pound per hour (lb/hr) for each Solar CTG and 26.97 lb/hr for the GE CTG. These mass emission rates correspond to 15 ppmvd @ 7 percent oxygen for the NWFREC project when firing biomass product gas in the CTG.

SECTION 4. APPENDIX ZZZZ

NESHAP, SUBPART ZZZZ – STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

A 500 kW or less emergency generator (EU 007) and a 335 hp or less fire pump (EU 008) are proposed for the NWFREC and they are subject to the requirements of 40 CFR 63, Subpart ZZZZ--National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. The complete provisions of Subpart ZZZZ may be provided in full upon request and are also available beginning at Section 63.6580 at:

Link to Subpart ZZZZ

Livingston, Sylvia

From: Livingston, Sylvia
Sent: Wednesday, April 27, 2011 4:08 PM
To: 'jdiesch@rentk.com'
Cc: 'gfarris@bioeh.com'; 'kdavis@bioeh.com'; 'sosbourn@golder.com'; 'abrams.heather@epa.gov'; 'db4635@aol.com'; 'marilynblackwel@wmconnect.com'; 'meg@ecolaw.biz'; 'hopeforcleanwater@yahoo.com'; 'bobfulford@nettally.com'; 'ronsaff@aol.com'; 'w_bunn1@bellsouth.net'; 'susiecaplowe@comcast.net'; 'daswim@gmail.com'; 'dave@no-burn.org'; 'nseldman@ilsr.org'; 'dmellman@post.harvard.edu'; 'drsammons@aol.com'; 'bradley@greenaction.org'; 'ring@tampabay.rr.com'; 'joecain1@comcast.net'; 'salters@magnet.fsu.edu'; 'sth@magnet.fsu.edu'; 'hluebkemann@comcast.net'; 'rstewart@fppaea.org'; 'richard.gragg@famu.edu'; 'tkspragg@yahoo.com'; 'gibbyj@earthlink.net'; Bradburn, Rick; Cooey, Sally; Diaz, Jennifer; Moore, Ronni; 'dan@Apalachicolariverkeeper.org'
Subject: Northwest Florida Renewable Energy Center (NWFREC), LLC; 0450012-002-AC
Attachments: 0450012-002-AC_Intent.pdf

Dear Sir/ Madam:

Attached is the official **Notice of Intent to Issue** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0450012.002.AC.D_pdf.zip

Owner/Company Name: BIOMASS ENERGY HOLDINGS, LLC
Facility Name: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.
Project Number: 0450012-002-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: GULF
Processor: David Read

Any questions or comments regarding this project should be directed to the processor reviewing the project. David Read at *850/717-9075* and *David.Read@dep.state.fl.us*.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://appprod.dep.state.fl.us/air/emission/apds/default.asp.

Permit project documents are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation

Livingston, Sylvia

From: Diesch, John H. [JDiesch@rentk.com]
Sent: Wednesday, April 27, 2011 4:34 PM
To: Livingston, Sylvia
Cc: Weeks, Sim; Corn, Dennis; Farris, Glenn [Contractor]
Subject: RE: Northwest Florida Renewable Energy Center (NWFREC), LLC; 0450012-002-AC

Dear Ms Livingston,

This email is to verify that I have received and can access and view the permit project documents.

Regards,

John Diesch

RENTECH

John H. Diesch, Sr. Vice President-Operations
Rentech, Inc. • 1331 17th Street Suite 720 • Denver, CO 80202
T: 720.274.3113 • C: 563.590.2767 • jdiesch@rentk.com • www.rentechinc.com

From: Livingston, Sylvia [mailto:Sylvia.Livingston@dep.state.fl.us]
Sent: Wednesday, April 27, 2011 2:04 PM
To: Diesch, John H.
Cc: gfarris@bioeh.com; kdavis@bioeh.com; sosbourn@golder.com; abrams.heather@epa.gov; db4635@aol.com; marilynblackwel@wmconnect.com; meg@ecolaw.biz; hopeforcleanwater@yahoo.com; bobfulford@nettally.com; ronsaff@aol.com; w_bunn1@bellsouth.net; susiecaplowe@comcast.net; daswim@gmail.com; dave@no-burn.org; nseldman@ilsr.org; dmellman@post.harvard.edu; drsammons@aol.com; bradley@greenaction.org; ring@tampabay.rr.com; joecain1@comcast.net; salters@magnet.fsu.edu; sth@magnet.fsu.edu; hluebkemann@comcast.net; rstewart@fppaea.org; richard.gragg@famu.edu; tkspragg@yahoo.com; gibbyj@earthlink.net; Bradburn, Rick; Cooey, Sally; Diaz, Jennifer; Moore, Ronni; dan@Apalachicolariverkeeper.org; Gibson, Victoria; Linero, Alvaro; Read, David; Walker, Elizabeth (AIR)
Subject: Northwest Florida Renewable Energy Center (NWFREC), LLC; 0450012-002-AC

Dear Sir/ Madam:

Attached is the official **Notice of Intent to Issue** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

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Click on the following link to access the permit project documents:

http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0450012.002.AC.D_pdf.zip

Owner/Company Name: BIOMASS ENERGY HOLDINGS, LLC
Facility Name: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.
Project Number: 0450012-002-AC
Permit Status: DRAFT

Permit Activity: CONSTRUCTION
Facility County: GULF
Processor: David Read

Any questions or comments regarding this project should be directed to the processor reviewing the project. David Read at *850/717-9075* and *David.Read@dep.state.fl.us*.

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Livingston, Sylvia

From: Scott Hannahs [sth@curg.org]
Sent: Wednesday, April 27, 2011 4:30 PM
To: Livingston, Sylvia
Subject: Change of address

On Apr 27, 2011, at 16:04, Livingston, Sylvia wrote:

Dear Sylvia,

Re: Northwest Florida Renewable Energy Center (NWFREC), LLC; 0450012-002-AC

PLEASE change my email address, which currently you have as sth@magnet.fsu.edu to sth@curg.org.

Scott Hannahs

Livingston, Sylvia

From: Karen Spragg [tkspragg@yahoo.com]
Sent: Wednesday, April 27, 2011 4:35 PM
To: Livingston, Sylvia
Subject: Re: Northwest Florida Renewable Energy Center (NWFREC), LLC; 0450012-002-AC

Recieved

"Livingston, Sylvia" <Sylvia.Livingston@dep.state.fl.us> wrote:

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>Click on the following link to access the permit project documents:
>http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/04500
>12.002.AC.D_pdf.zip
>
>Owner/Company Name: BIOMASS ENERGY HOLDINGS, LLC Facility Name:
>NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.
>Project Number: 0450012-002-AC
>Permit Status: DRAFT
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>Facility County: GULF
>
>Processor: David Read
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From: hopeforcleanwater@yahoo.com
Sent: Wednesday, April 27, 2011 8:25 PM
To: Livingston, Sylvia; 'jdiesch@rentk.com'
Cc: 'gfarris@bioeh.com'; 'kdavis@bioeh.com'; 'sosbourn@golder.com'; 'abrams.heather@epa.gov'; 'db4635@aol.com'; 'marilynblackwel@wmconnect.com'; 'meg@ecolaw.biz'; 'hopeforcleanwater@yahoo.com'; 'bobfulford@nettally.com'; 'ronsaff@aol.com'; 'w_bunn1@bellsouth.net'; 'susiecaplowe@comcast.net'; 'dave@no-burn.org'; 'nseldman@ilsr.org'; 'dmellman@post.harvard.edu'; 'drsammons@aol.com'; 'bradley@greenaction.org'; 'ring@tampabay.rr.com'; 'salters@magnet.fsu.edu'; 'sth@magnet.fsu.edu'; 'hluebkemann@comcast.net'; 'rstewart@fppaea.org'; 'richard.gragg@famu.edu'; 'tkspragg@yahoo.com'; 'gibbyj@earthlink.net'; Bradburn, Rick; Cooey, Sally; Diaz, Jennifer; Moore, Ronni; 'dan@Apalachicolariverkeeper.org'
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Date: Wed, 27 Apr 2011 16:07:39 -0400
To: 'jdiesch@rentk.com'<'jdiesch@rentk.com'>
Cc: 'gfarris@bioeh.com'<'gfarris@bioeh.com'>; 'kdavis@bioeh.com'<'kdavis@bioeh.com'>; 'sosbourn@golder.com'<'sosbourn@golder.com'>; 'abrams.heather@epa.gov'<'abrams.heather@epa.gov'>; 'db4635@aol.com'<'db4635@aol.com'>; 'marilynblackwel@wmconnect.com'<'marilynblackwel@wmconnect.com'>; 'meg@ecolaw.biz'<'meg@ecolaw.biz'>; 'hopeforcleanwater@yahoo.com'<'hopeforcleanwater@yahoo.com'>; 'bobfulford@nettally.com'<'bobfulford@nettally.com'>; 'ronsaff@aol.com'<'ronsaff@aol.com'>; 'w_bunn1@bellsouth.net'<'w_bunn1@bellsouth.net'>; 'susiecaplowe@comcast.net'<'susiecaplowe@comcast.net'>; 'daswim@gmail.com'<'daswim@gmail.com'>; 'dave@no-burn.org'<'dave@no-burn.org'>; 'nseldman@ilsr.org'<'nseldman@ilsr.org'>; 'dmellman@post.harvard.edu'<'dmellman@post.harvard.edu'>; 'drsammons@aol.com'<'drsammons@aol.com'>; 'bradley@greenaction.org'<'bradley@greenaction.org'>; 'ring@tampabay.rr.com'<'ring@tampabay.rr.com'>; 'joecain1@comcast.net'<'joecain1@comcast.net'>; 'salters@magnet.fsu.edu'<'salters@magnet.fsu.edu'>; 'sth@magnet.fsu.edu'<'sth@magnet.fsu.edu'>; 'hluebkemann@comcast.net'<'hluebkemann@comcast.net'>; 'rstewart@fppaea.org'<'rstewart@fppaea.org'>; 'richard.gragg@famu.edu'<'richard.gragg@famu.edu'>; 'tkspragg@yahoo.com'<'tkspragg@yahoo.com'>; 'gibbyj@earthlink.net'<'gibbyj@earthlink.net'>; Bradburn, Rick<Rick.Bradburn@dep.state.fl.us>; Cooey, Sally<Sally.Cooey@dep.state.fl.us>; Diaz, Jennifer<Jennifer.Diaz@dep.state.fl.us>; Moore, Ronni<Ronni.Moore@dep.state.fl.us>; 'dan@Apalachicolariverkeeper.org'<'dan@Apalachicolariverkeeper.org'>
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Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: GULF
Processor: David Read

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Livingston, Sylvia

From: Marilynblackwel@wmconnect.com
Sent: Thursday, April 28, 2011 12:30 AM
To: Livingston, Sylvia
Subject: Re: Northwest Florida Renewable Energy Center (NWFREC), LLC; 0450012-002-AC

I can view the documents, Thank You.

Marilyn Blackwell</HTML>

Livingston, Sylvia

From:	Joy Towles Ezell [hopeforcleanwater@yahoo.com]
Sent:	Thursday, April 28, 2011 9:52 AM
To:	Linero, Alvaro
Cc:	Livingston, Sylvia
Subject:	Re: Northwest Florida Renewable Energy Center (NWFREC), LLC;0450012-002-AC

But Al, he/they say they have a whole new process that they are going to use...shouldn't that be considered??
Are they seeking a permit for Rentech or for GCSEC ?? Why not require them to send in the correct paperwork?

Joy

Joy Towles Ezell
hopeforcleanwater@yahoo.com
850 584 7087 office & fax
850 843 1574 cell

From: "Linero, Alvaro" <Alvaro.Linero@dep.state.fl.us>
To: "hopeforcleanwater@yahoo.com" <hopeforcleanwater@yahoo.com>
Cc: "Livingston, Sylvia" <Sylvia.Livingston@dep.state.fl.us>
Sent: Thu, April 28, 2011 8:29:09 AM
Subject: RE: Northwest Florida Renewable Energy Center (NWFREC), LLC;0450012-002-AC

Thanks Joy.

We were informed and the actual notices have the correct company name.

The information on the bottom of the email may have been carried over from the original application.

Sincerely,

Al Linero.

From: hopeforcleanwater@yahoo.com [mailto:hopeforcleanwater@yahoo.com]
Sent: Wednesday, April 27, 2011 8:25 PM
To: Livingston, Sylvia; 'jdiesch@rentk.com'
Cc: 'gfarris@bioeh.com'; 'kdavis@bioeh.com'; 'sosbourn@golder.com'; 'abrams.heather@epa.gov'; 'db4635@aol.com'; 'marilynblackwel@wmconnect.com'; 'meg@ecolaw.biz'; 'hopeforcleanwater@yahoo.com'; 'bobfulford@nettally.com'; 'ronsaff@aol.com'; 'w_bunn1@bellsouth.net'; 'susiecaplowe@comcast.net'; 'dave@no-burn.org'; 'nseldman@ilsr.org'; 'dmellman@post.harvard.edu'; 'drsammons@aol.com'; 'bradley@greenaction.org'; 'ring@tampabay.rr.com'; 'salters@magnet.fsu.edu'; 'sth@magnet.fsu.edu'; 'hluebkemann@comcast.net'; 'rstewart@fppaea.org'; 'richard.gragg@famu.edu'; 'tkspragg@yahoo.com'; 'gibbyj@earthlink.net'; Bradburn, Rick; Cooey, Sally; Diaz, Jennifer; Moore, Ronni; 'dan@Apalachicolariverkeeper.org'
Subject: Re: Northwest Florida Renewable Energy Center (NWFREC), LLC;0450012-002-AC

Sylvia
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name, & the proposed process has supposedly changed, or did s glenn farris not advise DEP ?
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Please advise.
Thanks
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Sent from my Verizon Wireless BlackBerry

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Date: Wed, 27 Apr 2011 16:07:39 -0400
To: 'jdiesch@rentk.com'<'jdiesch@rentk.com'>
Cc: 'gfarris@bioeh.com'<'gfarris@bioeh.com'>; 'kdavis@bioeh.com'<'kdavis@bioeh.com'>; 'sosbourn@golder.com'<'sosbourn@golder.com'>; 'abrams.heather@epa.gov'<'abrams.heather@epa.gov'>; 'db4635@aol.com'<'db4635@aol.com'>; 'marilynblackwel@wmconnect.com'<'marilynblackwel@wmconnect.com'>; 'meg@ecolaw.biz'<'meg@ecolaw.biz'>; 'hopeforcleanwater@yahoo.com'<'hopeforcleanwater@yahoo.com'>; 'bobfulford@nettally.com'<'bobfulford@nettally.com'>; 'ronsaff@aol.com'<'ronsaff@aol.com'>; 'w_bunn1@bellsouth.net'<'w_bunn1@bellsouth.net'>; 'susiecaplowe@comcast.net'<'susiecaplowe@comcast.net'>; 'daswim@gmail.com'<'daswim@gmail.com'>; 'dave@no-burn.org'<'dave@no-burn.org'>; 'nseldman@ilsr.org'<'nseldman@ilsr.org'>; 'dmellman@post.harvard.edu'<'dmellman@post.harvard.edu'>; 'drsammons@aol.com'<'drsammons@aol.com'>; 'bradley@greenaction.org'<'bradley@greenaction.org'>; 'ring@tampabay.rr.com'<'ring@tampabay.rr.com'>; 'joecain1@comcast.net'<'joecain1@comcast.net'>; 'salters@magnet.fsu.edu'<'salters@magnet.fsu.edu'>; 'sth@magnet.fsu.edu'<'sth@magnet.fsu.edu'>; 'hluebkemann@comcast.net'<'hluebkemann@comcast.net'>; 'rstewart@fppaea.org'<'rstewart@fppaea.org'>; 'richard.gragg@famu.edu'<'richard.gragg@famu.edu'>; 'tkspragg@yahoo.com'<'tkspragg@yahoo.com'>; 'gibbyj@earthlink.net'<'gibbyj@earthlink.net'>; Bradburn, Rick<Rick.Bradburn@dep.state.fl.us>; Cooey, Sally<Sally.Cooey@dep.state.fl.us>; Diaz, Jennifer<Jennifer.Diaz@dep.state.fl.us>; Moore, Ronni<Ronni.Moore@dep.state.fl.us>; 'dan@Apalachicolariverkeeper.org'<'dan@Apalachicolariverkeeper.org'>
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Facility County: GULF
Processor: David Read
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Livingston, Sylvia

From: Linero, Alvaro
Sent: Thursday, April 28, 2011 8:29 AM
To: hopeforcleanwater@yahoo.com
Cc: Livingston, Sylvia
Subject: RE: Northwest Florida Renewable Energy Center (NWFREC), LLC;0450012-002-AC

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From: Bill [drsammons@aol.com]
Sent: Thursday, April 28, 2011 10:13 AM
To: Livingston, Sylvia
Subject: Re: Northwest Florida Renewable Energy Center (NWFREC), LLC; 0450012-002-AC

Did access documents.

Bill Sammons

-----Original Message-----
From: Livingston, Sylvia <Sylvia.Livingston@dep.state.fl.us>
To: jdiesch@rentk.com <jdiesch@rentk.com>
Cc: gfarris@bioeh.com <gfarris@bioeh.com>; kdavis@bioeh.com <kdavis@bioeh.com>; sosbourn@golder.com <sosbourn@golder.com>; abrams.heather@epa.gov <abrams.heather@epa.gov>; db4635@aol.com <db4635@aol.com>; marilynblackwel@wmconnect.com <marilynblackwel@wmconnect.com>; meg@ecolaw.biz <meg@ecolaw.biz>; hopeforcleanwater@yahoo.com <hopeforcleanwater@yahoo.com>; bobfulford@nettally.com <bobfulford@nettally.com>; ronsaff@aol.com <ronsaff@aol.com>; w_bunn1@bellsouth.net <w_bunn1@bellsouth.net>; susiecaplowe@comcast.net <susiecaplowe@comcast.net>; daswim@gmail.com <daswim@gmail.com>; dave@no-burn.org <dave@no-burn.org>; nseldman@ilsr.org <nseldman@ilsr.org>; dmellman@post.harvard.edu <dmellman@post.harvard.edu>; drsammons@aol.com <drsammons@aol.com>; bradley@greenaction.org <bradley@greenaction.org>; ring@tampabay.rr.com <ring@tampabay.rr.com>; joecain1@comcast.net <joecain1@comcast.net>; salters@magnet.fsu.edu <salters@magnet.fsu.edu>; sth@magnet.fsu.edu <sth@magnet.fsu.edu>; hluebkemann@comcast.net <hluebkemann@comcast.net>; rstewart@fppaea.org <rstewart@fppaea.org>; richard.gragg@famu.edu <richard.gragg@famu.edu>; tkspragg@yahoo.com <tkspragg@yahoo.com>; gibbyj@earthlink.net <gibbyj@earthlink.net>; Bradburn, Rick <Rick.Bradburn@dep.state.fl.us>; Cooey, Sally <Sally.Cooey@dep.state.fl.us>; Diaz, Jennifer <Jennifer.Diaz@dep.state.fl.us>; Moore, Ronni <Ronni.Moore@dep.state.fl.us>; dan@Apalachicolariverkeeper.org <dan@Apalachicolariverkeeper.org>; Gibson, Victoria <Victoria.Gibson@dep.state.fl.us>; Linero, Alvaro <Alvaro.Linero@dep.state.fl.us>; Read, David <David.Read@dep.state.fl.us>; Walker, Elizabeth (AIR) <Elizabeth.Walker@dep.state.fl.us>
Sent: Wed, Apr 27, 2011 1:04 pm
Subject: Northwest Florida Renewable Energy Center (NWFREC), LLC; 0450012-002-AC

Dear Sir/ Madam:

Attached is the official **Notice of Intent to Issue** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:

http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0450012.002.AC.D_pdf.zip

Owner/Company Name: BIOMASS ENERGY HOLDINGS, LLC
Facility Name: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.
Project Number: 0450012-002-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: GULF
Processor: David Read

Any questions or comments regarding this project should be directed to the processor reviewing the project. David Read at *850/717-9075* and *David.Read@dep.state.fl.us*.